energy market consulting associates

Regulatory Submission for period 2021/22 to 2025/26

UNITED ENERGY - REVIEW OF ASPECTS OF PROPOSED EXPENDITURE

Report prepared for:

AUSTRALIAN ENERGY REGULATOR

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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 United Energy 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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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
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
AI	Artificial Intelligence
ALARP	As Low As Reasonably Practicable
AMI	Advanced Metering Infrastructure
AMS	Asset Management System
augex	Augmentation capital expenditure
B/C	Benefit/Cost
BC	Business Case
BH	Box Hill
BMP	Bushfire Management Plan
BST	Base Step Trend
C55	Copperleaf's C55 Software
Capex	Capital expenditure
CBA	Cost Benefit Analysis
CBRM	Condition Based Risk Management
CCC	Customer Consultative Committee
CFD	Caulfield substation
CIC	Capital Investment Committee
CIE	Centre of International Economics
CMEN	Common Multiple Earthed Neutral
CP	CitiPower
DAPR	Distribution Annual Planning Report
DBYD	Dial Before You Dig
DC	Doncaster substation (or refers to Direct Current)
DER	Distributed Energy Resource

Term	Definition
DERMS	Distributed Energy Resource Management System
DNSP	Distribution Network Service Provider
DSS	Distribution Substation
DVMS	Dynamic Voltage Management System
EBSS	Efficiency Benefit Sharing Scheme
EDPR	Electricity Distribution Price Review
EFCAP	Energy Futures Customer Advisory Panel
EMF	Environment Management Framework
EMS	Enterprise Management Systems
EMT	Executive Management Team
ERM	Enterprise Risk Management
ERP	Enterprise Resource Planning
ESMS	Electricity Safety Management System
ESV	Energy Safe Victoria
FSH	Frankston South
FY	Financial Year
GIS	Geospatial Information System
GPS	Global Positioning System
HI	Health Index
HV	High Voltage
IaaS	Infrastructure as a Service
ICT	Information and Communications Technology
INMS	Integrated Network Management System
IR	Information Request
ISO	International Organization for Standardization
IVR	Interactive Voice Response
LCTA	Lowest Cost Technically Acceptable
LDC	Load Duration Curves
LSAA	Local Service Area Agents
LV	Low Voltage
MGL	Multi-Greek Letter
MIL	Maturity Indicator Level
NER	National Electricity Rules
NIEIR	National Institute of Economic and Industry Research
NNS	Non-network Solutions

Term	Definition
NSA	Network Services Agreement
OHSMS	Occupational Health and Safety Management System
OLTC	On-load Tap Changer
opex	Operating expenditure
OT	Operational Technology
PAL	Powercor
PL	Public Lighting
PoE	Probability of Exceedance
PoF	Probability of Failure
PPCF	Portfolio and Project Controls Framework
PQ	Power Quality
PV	Photovoltaic (solar); or Present Value (depending on context)
PVC	Poly Vinyl Chloride
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 - Distribution
RMCC	Risk Management and Compliance Committee
RP	Regulatory Proposal
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAPN	South Australia Power Networks
SCADA	Supervisory Control and Data Acquisition
SCS	Standard Control Services
SE	Solar Enablement
SME	Subject Matter Experts
SSP	Summer Saver Program
TSTS	Templestowe Terminal Station
UCS	Unified Computing System
UE	United Energy
UoS	Use of System
VCR	Value of Customer Reliability

Term	Definition
VPN	Victoria Power Networks
WAN	Wide Area Network
ZS	Zone substation

1 INTRODUCTION

1.1 Scope

1. This report provides our assessment of certain aspects of United Energy'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 United Energy;
- 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 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 United Energy (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 United Energy's investment governance and management frameworks and relevant aspects of its expenditure forecasting methodologies.
- In section 4, we provide our assessment of United Energy's proposed repex.
- In section 5, we provide our assessment of United Energy's proposed non-DER augex.
- In section 6, we provide our assessment of United Energy'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 United Energy'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 United Energy's proposed property capex.
- In Section 9, we provide our assessment of United Energy's proposed addition of an allowance for minor repairs to United Energy's base opex.

4. We provide contextual information related to consideration of an enhanced pole replacement program for United Energy in Appendix A.

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 from information provided by the business in other terms.[1]

6. United Energy has proposed expenditure allowances which it has real-cost escalated in aggregate. However, project and program-level information presented by United Energy (such as in the project models and business cases) has generally not had escalation applied to it, and we have presented it in non-escalated terms in this report to preserve comparability with the project information 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 is what United Energy has applied in its RIN. In some cases, we observe that United Energy has used different indices in 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, with some wider information shown for context. We show in turn, United Energy's proposed:

- Total net capex;
- Repex;
- Augex (including solar enablement capex);
- ICT capex;
- Property-related capex; and
- Opex step change and category change allowances, including for ICT Cloud-related opex, for solar enablement and for minor repairs.

9. The graphs and tables that follow document the expenditures that we have been asked to assess. It includes RIN data provided by United Energy 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 categories, with the exception that we have combined poles expenditure and pole staking expenditure;
- Augex data by 'function types' that United Energy has defined;
- ICT expenditure by project, and as categorised by United Energy as Recurrent and Non-recurrent by the AER; and
- Property expenditure by project (individual depots) and programs (facilities upgrades and compliance program).

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

11. United Energy 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.

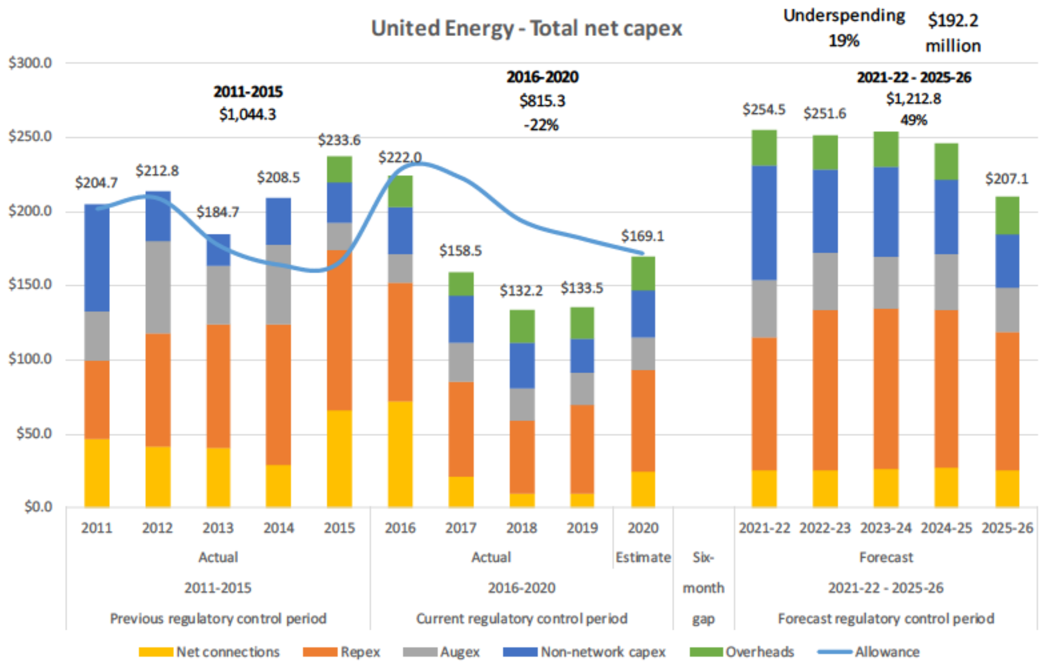
12. In this section, we provide some high-level trend information for context. More focused expenditure and trend information, relevant to our assessments, is provided in the assessment sections of this report.

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

2.2 Total Net Capex

14. The figure below shows actual and estimated United Energy total net capex vs AER allowance for the prior and current RCP's and forecast United Energy total net capex for the next RCP.

Figure 2.1: United Energy 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. The following table shows repex by RIN Group as reported in the RIN. United Energy's total forecast repex for the next RCP is $504.9m. This mirrors how repex was presented in United Energy's Regulatory Proposal (RP). It includes the Environmental Management program, under RIN Group "Other", which has since been withdrawn by United Energy and substituted with a much lower amount.

16. Table 2.2 shows our assessment of the proposed Repex by RIN Group after adjustment of the Environmental Management program.

Table 2.1: United Energy repex for the next RCP – As reported in RP - $m, real 2021

Group	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Poles	16.9	18.1	19.1	19.4	20.5	94.0
Pole Top Structures	15.1	15.3	15.5	15.8	16.0	77.7
Overhead Conductors	3.0	3.1	3.1	3.1	2.9	15.2
Underground Cables	5.6	5.8	6.3	6.5	6.3	30.6
Service Lines	5.1	5.1	5.0	4.9	4.8	24.9
Transformers	8.6	9.5	10.2	10.0	9.6	47.8
Switchgear	13.4	14.7	15.8	15.2	14.6	73.7
SCADA, Network Control and Protection	7.9	11.5	7.6	10.1	6.5	43.7
Other	13.6	25.2	25.4	21.4	11.9	97.4
Total	**89.3**	**108.2**	**108.0**	**106.4**	**93.1**	**504.9**

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

Table 2.2: United Energy Repex for the next RCP with Environmental Management program removed - $m, real 2021

Group	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Poles	16.9	18.1	19.1	19.4	20.5	94.0
Pole Top Structures	15.1	15.3	15.5	15.8	16.0	77.7
Overhead Conductors	3.0	3.1	3.1	3.1	2.9	15.2
Underground Cables	5.6	5.8	6.3	6.5	6.3	30.6
Service Lines	5.1	5.1	5.0	4.9	4.8	24.9
Transformers	8.6	9.5	10.2	10.0	9.6	47.8
Switchgear	13.4	14.7	15.8	15.2	14.6	73.7
SCADA, Network Control and Protection	7.9	11.5	7.6	10.1	6.5	43.7
Other	2.1	2.6	3.1	2.6	1.8	12.2
Total	**77.8**	**85.6**	**85.8**	**87.7**	**82.9**	**419.8**

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

Repex from the project models as mapped to RIN Groups

17. The table below shows project-level repex from information request IR 34 as mapped to RIN Groups by United Energy.[2] Real cost escalation has not been included. The originally proposed Environmental Management program has been removed from the "Other" group and substituted to match United Energy's updated regulatory proposal. United Energy's amended total forecast repex for the next RCP is $403.1m (excluding real cost escalation).

[2] The source file (IR34 – MOD 4.03) uses $2019 for the Project List, and which we converted to $2021, but $2021 for the unitised list. Except in regard to the environmental management program (within RIN category "Other") these RCP totals also reconcile to UE's $2021-denominated "RIN Reconciliation" sheet within IR34.

Table 2.3: United Energy repex for the next RCP – As Amended by UE (After withdrawals) - $m, real 2021

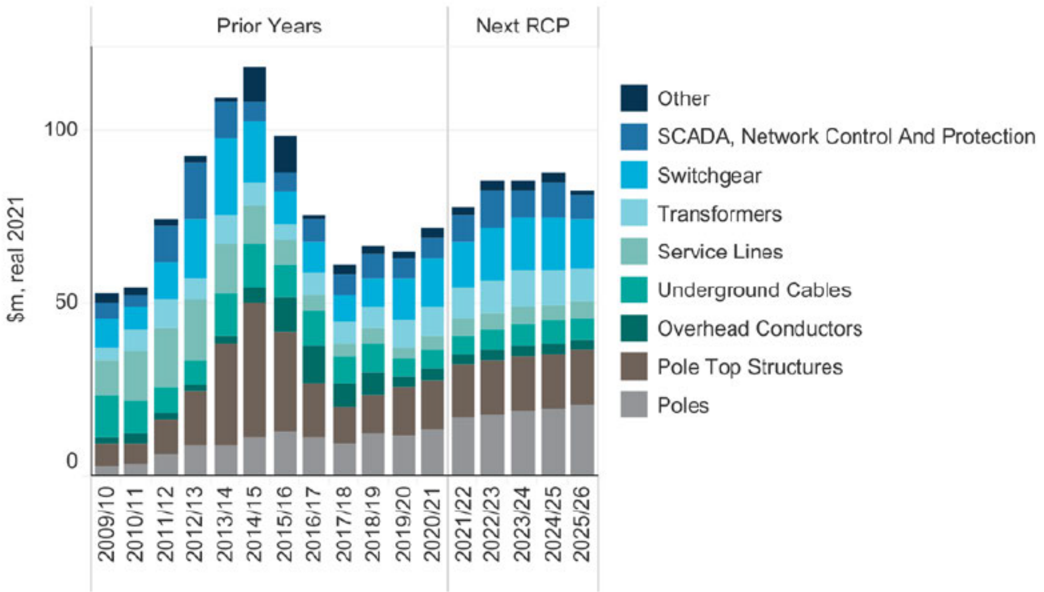
Group	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Poles	16.7	17.6	18.4	18.4	19.2	90.2
Pole Top Structures	14.9	14.9	14.9	15.0	14.9	74.6
Overhead Conductors	3.0	3.0	3.0	3.0	2.7	14.6
Underground Cables	5.5	5.6	6.1	6.2	5.9	29.3
Service Lines	5.1	4.9	4.8	4.6	4.5	23.9
Transformers	8.5	9.2	9.7	9.5	9.0	45.9
Switchgear	13.2	14.3	15.1	14.4	13.7	70.7
SCADA, Network Control and Protection	7.8	11.2	7.3	9.6	6.1	42.0
Other	2.0	2.5	3.0	2.5	1.7	11.9
Total	**76.8**	**83.3**	**82.3**	**83.1**	**77.7**	**403.1**

Source: EMCa analysis of United Energy IR 34 response 'AER IR034 - UE MOD 4.03 - mapping reconciliation V1.0'. All values exclude real cost escalation. Excludes 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 data has been populated using escalated project model data provided by the AER. Forecast values 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: United Energy repex – As Amended by UE (After withdrawals) - $m, real 2021



Source: EMCa analysis of 'United Energy - RIN001 - Workbook 1 - Reg Determination - 31 January 2020', 'United Energy - RIN008 - Workbook 8 - Historical FY CAT - 31 January 2020', 'UE consolidated RIN – Repex'. Excludes Environmental Management program.

Repex by program, showing AER focus projects

19. The following 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: United Energy repex (as amended by United Energy) showing only AER Focus Projects and Programs[3] - $m, real 2021

Group / Focus	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Poles	16.7	17.6	18.4	18.4	19.2	90.2
Focus: Pole Replacements program	*16.7*	*17.6*	*18.4*	*18.4*	*19.2*	*90.2*
Pole Top Structures	14.9	14.9	14.9	15.0	14.9	74.6
Overhead Conductors	3.0	3.0	3.0	3.0	2.7	14.6
Underground Cables	5.5	5.6	6.1	6.2	5.9	29.3
Focus: ZS Transformers & Switchgear	*1.2*	*1.3*	*1.2*	*1.4*	*1.6*	*6.7*
Other	*4.3*	*4.4*	*4.8*	*4.8*	*4.3*	*22.6*
Service Lines	5.1	4.9	4.8	4.6	4.5	23.9
Focus: Service Lines	*5.1*	*4.9*	*4.8*	*4.6*	*4.5*	*23.9*
Transformers	8.5	9.2	9.7	9.5	9.0	45.9
Focus: ZS Transformers & Switchgear	*3.4*	*3.9*	*4.6*	*4.9*	*4.6*	*21.4*
Other	*5.1*	*5.4*	*5.2*	*4.6*	*4.4*	*24.5*
Switchgear	13.2	14.3	15.1	14.4	13.7	70.7
Focus: ZS Transformers & Switchgear	*2.6*	*3.3*	*3.8*	*3.5*	*3.4*	*16.6*
Other	*10.6*	*11.0*	*11.3*	*10.9*	*10.3*	*54.1*
SCADA, Network Control and Protection	7.8	11.2	7.3	9.6	6.1	42.0
Focus: SCADA	*7.2*	*10.5*	*6.5*	*8.8*	*5.3*	*38.3*
Focus: ZS Transformers & Switchgear	*0.6*	*0.7*	*0.8*	*0.8*	*0.8*	*3.7*
Other	2.0	2.5	3.0	2.5	1.7	11.9
Focus: ZS Transformers & Switchgear	*0.4*	*0.7*	*1.0*	*0.8*	*0.5*	*3.4*
Other	1.7	1.9	2.0	1.7	1.3	8.6
Total	**76.8**	**83.3**	**82.3**	**83.1**	**77.7**	**403.1**

Source: EMCa Analysis of United Energy IR 34 response 'AER IR034 - UE MOD 4.03 - mapping reconciliation V1.0'. Excludes real cost escalation

2.3.2 Augex

RIN data

20. Table 2.4 below shows United Energy's proposed augex for the next RCP as reported in the RIN and RP by RIN Group. United Energy's total forecast augex is $182.0m.

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[3] ZS is an abbreviation for Zone Substations

Table 2.5: United Energy augex for the next RCP – As reported in RP - $m, real 2021

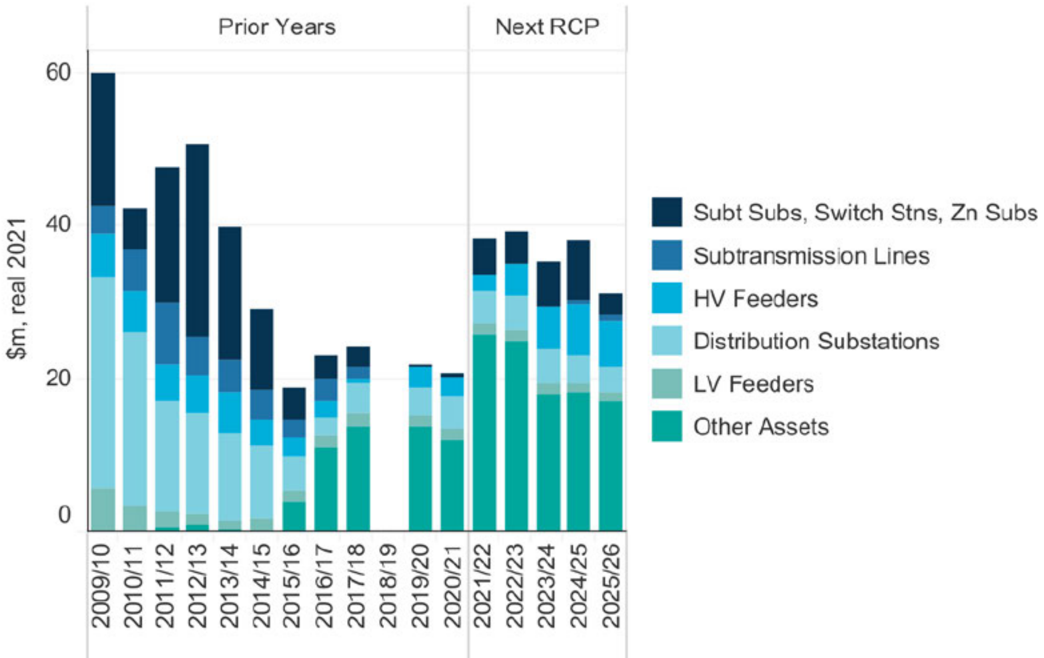
Group	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Subtransmission Substations, Switching Stations, Zone Substations	4.7	4.3	5.8	7.7	3.0	25.5
Subtransmission Lines	0.0	0.0	0.0	0.5	0.7	1.2
HV Feeders	2.3	4.1	5.8	6.7	6.0	24.8
Distribution Substations	4.2	4.4	4.4	3.7	3.3	19.9
LV Feeders	1.4	1.5	1.5	1.2	1.1	6.7
Other Assets	25.7	25.0	17.9	18.1	17.1	103.8
Total	**38.3**	**39.2**	**35.3**	**38.0**	**31.2**	**182.0**

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

Augex trend

21. Augex trends over time, by RIN Group, 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: United Energy augex trend - $m, real 2021



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

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

22. Table 2.5 below shows United Energy's augex project expenditure for the next RCP, organised by the Function Types provided in MOD 6.01. This table also shows forecast augex for each of the AER focus projects that we assessed. 'remainder' augex is included for reconciliation purposes. Real cost escalation has been excluded.

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

Group / Focus & BC	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Subtransmission Substations, Switching Stations, Zone Substations	**4.6**	**4.2**	**5.6**	**7.3**	**2.8**	**24.6**
AER Focus	4.4	4.1	5.2	6.9	2.3	22.9
Doncaster SA			*4.3*	*2.1*		*6.4*
EM SA		*1.9*	*0.9*			*2.8*
KBH SA	*4.4*	*2.2*				*6.6*
MTN SA				*4.7*	*2.3*	*7.1*
Remainder	0.2	0.1	0.4	0.5	0.5	1.7
Subtransmission Lines				**0.5**	**0.7**	**1.2**
HV Feeders	**2.3**	**4.0**	**5.5**	**6.4**	**5.6**	**23.7**
AER Focus	0.5	2.3	2.3			5.1
EM SA		*2.3*	*2.3*			*4.7*
MTN SA	*0.5*					*0.5*
Remainder	1.8	1.6	3.2	6.4	5.6	18.6
Distribution Substations	**4.1**	**4.3**	**4.2**	**3.5**	**3.1**	**19.2**
LV Feeders	**1.4**	**1.5**	**1.4**	**1.2**	**1.0**	**6.5**
Other Assets	**25.6**	**24.1**	**17.0**	**17.0**	**15.4**	**99.1**
AER Focus	7.5	9.6	8.7	9.2	7.5	42.4
Solar Enablement	*7.5*	*9.6*	*8.7*	*9.2*	*7.5*	*42.4*
Remainder	18.1	14.5	8.4	7.8	7.9	56.7
Total	**38.0**	**38.0**	**33.8**	**35.8**	**28.7**	**174.3**

Source: EMCa analysis of UED MOD 6.01. Excludes real cost escalation

2.3.3 ICT

RIN data

23. The following table shows proposed ICT capex by RIN Category for the next RCP, including real cost escalation. Total forecast ICT capex is $194.3m.

Table 2.7: United Energy ICT capex for the next RCP - $m, real 2021

Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Corporate Services	4.0	5.2	3.8	12.3	3.6	28.9
Customer Engagement	12.1	2.3	2.6	0.9	0.2	18.1
Cyber Security	6.7	3.5	2.6	2.8	3.9	19.4
Field Work & Construction	2.7	7.1	12.8	9.4	1.3	33.1
Market Compliance	19.0	5.2	2.9	2.2	5.1	34.4
Network Assets and Network Operations	11.0	14.6	14.6	7.5	9.4	57.1
Service Management and Ops	0.8	0.5	0.5	0.6	0.8	3.3
Total	**56.3**	**38.4**	**39.8**	**35.6**	**24.1**	**194.3**

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

ICT capex projects categorised as Recurrent/Non-recurrent

24. In Table 2.7 below, ICT capex for the next RCP is categorised from United Energy's project models as Recurrent or Non-Recurrent expenditure. AER focus projects have been highlighted. Real cost escalation has been excluded.

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

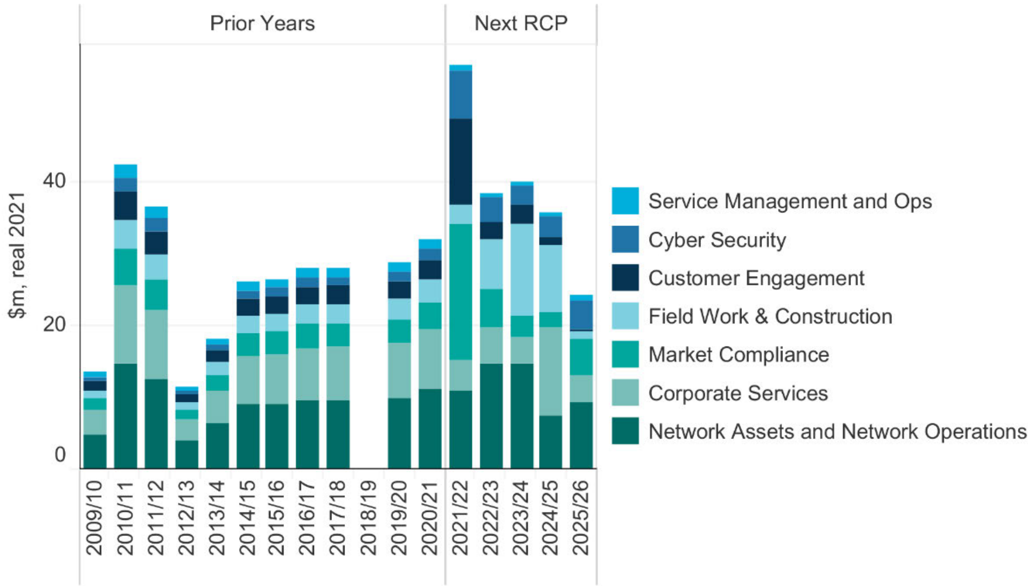
Project	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Recurrent	**26.3**	**20.6**	**15.6**	**21.4**	**19.3**	**103.2**
AER Focus projects						
Infrastructure with Cloud migration	3.9	4.4	2.9	8.4	3.2	22.8
Network Management	5.0	5.2	4.0	4.2	6.4	24.9
Other						
BI/BW	0.5	1.1	0.5	0.1	0.1	2.3
Customer Enablement		0.6				0.6
Cyber security	4.6	2.4	1.7	1.9	2.5	13.1
Device replacement	0.8	0.5	0.5	0.6	0.7	3.1
Enterprise Management Systems - Non-SAP	3.0	1.7	2.1	1.2	0.8	8.7
Facilities' security	0.1	0.6	0.7	3.2	0.1	4.7
General compliance	1.6	1.6	1.6	1.6	1.6	8.2
Market Systems	2.8	0.4	1.0	0.3	2.8	7.4
SAP S/4HANA	0.9	1.5			0.7	3.1
Telephony	3.0	0.6	0.6		0.2	4.4
Non-recurrent	**29.2**	**16.6**	**22.4**	**12.1**	**3.1**	**83.4**
5 Minute Settlements	14.2	3.0	0.1	0.1	0.2	17.7
Customer Enablement	8.9	1.1	1.9	0.9		12.7
Cyber security	1.9	1.0	0.7	0.8	1.1	5.6
Digital network	4.1	6.5	5.6	1.3	1.8	19.4
Intelligent engineering		1.4	3.1	0.8		5.4
SAP S/4HANA		3.5	10.9	8.2		22.6
Total	**55.5**	**37.3**	**38.0**	**33.5**	**22.4**	**186.7**

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

ICT capex trend

25. 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. All expenditure has been inflated to Real 2021 dollars and includes real cost escalation.

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

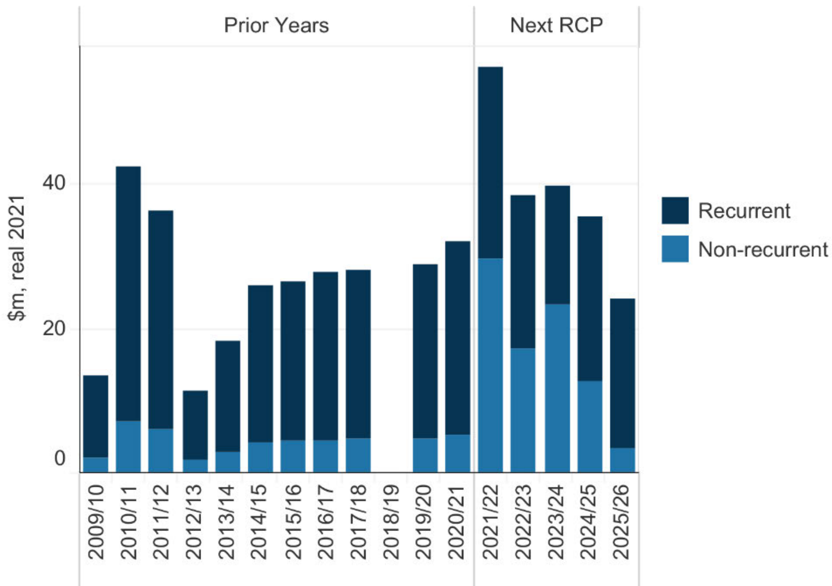


Source: EMCa analysis of 'United Energy - RIN001 - Workbook 1 - Reg Determination - 31 January 2020', 'United Energy - RIN008 - Workbook 8 - Historical FY CAT - 31 January 2020'

ICT Capex trends by Recurrent/Non-Recurrent expenditure classification

26. Figure 2.5 below shows United Energy's ICT capex trend for prior years and the next RCP, categorised by Recurrent and Non-recurrent expenditure.

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



Source: EMCa analysis of 'United Energy - RIN001 - Workbook 1 - Reg Determination - 31 January 2020', 'United Energy - RIN008 - Workbook 8 - Historical FY CAT - 31 January 2020' (United Energy also provided historical data in Workbook 2. That data is in calendar years. While United Energy 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

27. Property expenditure is not broken down in the RIN, existing only as a single line item for "Total buildings and property expenditure". Table 2.9 below shows total forecast property expenditure of $71.0m for the next RCP as presented in the RIN, including real cost escalation.

Table 2.9: United Energy property capex for next RCP - $m, real 2021

Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Total buildings and property expenditure	15.8	15.5	18.0	12.4	9.4	71.0
Total	**15.8**	**15.5**	**18.0**	**12.4**	**9.4**	**71.0**

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

Project data

28. Table 2.10 shows forecast property capex from the project models for facilities and by depot location. This data excludes real cost escalation.

Table 2.10: United Energy proposed Property Projects - $m, real 2021

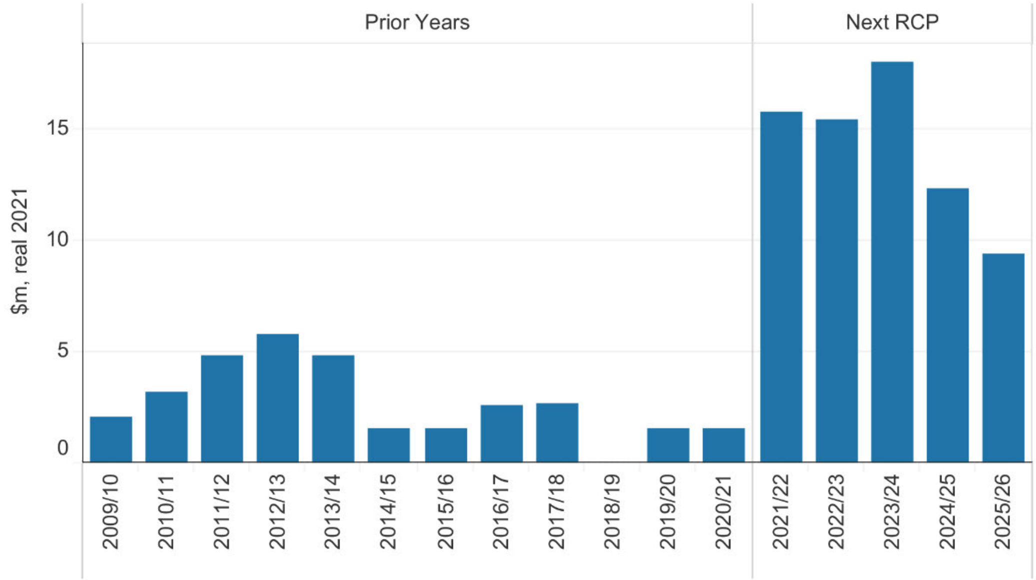
Project	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Facilities			0.9			0.9
Depots	15.5	15.1	16.5	11.9	9.1	68.2
Burwood	*15.5*	*15.1*				*30.7*
Keysborough			*16.5*	*5.6*		*22.1*
Mornington				*6.4*	*9.1*	*15.4*
Total	**15.5**	**15.1**	**17.5**	**11.9**	**9.1**	**69.1**

Source: EMCa analysis of United Energy MOD 8.02, 8.03. Excludes real cost escalation

Property capex trend

29. In Figure 2.6 below, United Energy's property capex trend over time has been generated for prior years and the next RCP 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 2.6: United Energy property capex trend - $m, real 2021



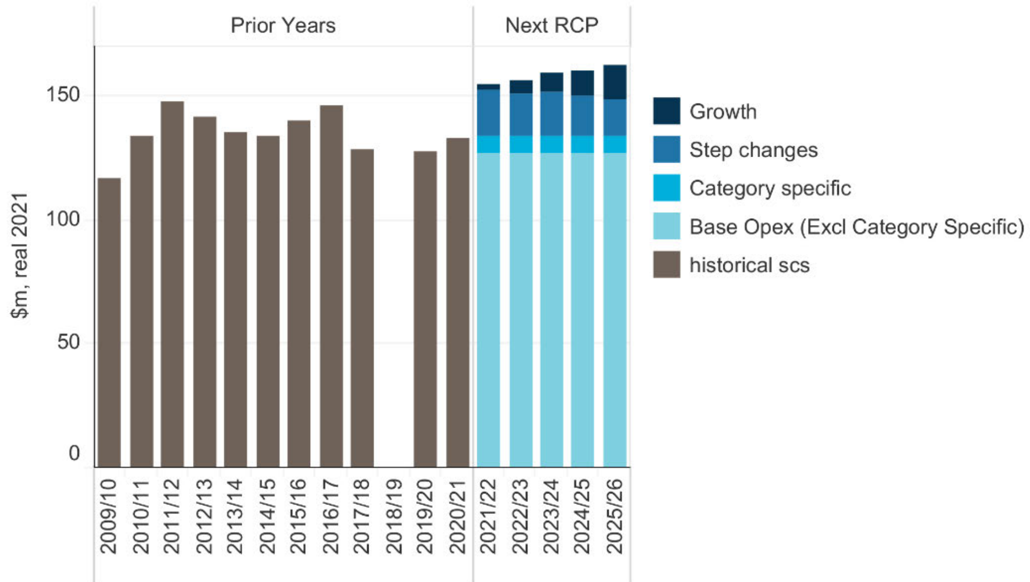
Source: Source: EMCa analysis of 'United Energy - RIN001 - Workbook 1 - Reg Determination - 31 January 2020', 'United Energy - RIN008 - Workbook 8 - Historical FY CAT - 31 January 2020'

2.3.5 Opex

Opex Trend and overview of next RCP

30. 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 includes real cost escalation.

Figure 2.7: United Energy opex trend - $m, real 2021 - $m, real 2021



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

Step Changes and 'Category Specific' Opex over the next RCP

31. Proposed 'Step changes' and 'Category Specific' Opex for the next RCP are further categorised in the table below. Real cost escalation has been included.

Figure 2.8: United Energy'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	**18.6**	**17.2**	**18.1**	**16.5**	**15.3**	**85.6**
5-minute settlement	0.6	0.6	0.8	0.9	1.1	3.9
Demand management programs	1.5	1.6	2.1	2.0	1.5	8.6
EPA regulations change	3.6	3.4	3.2	1.3	0.4	11.8
ESV levy	0.4	0.5	0.5	0.5	0.5	2.5
Financial year RIN	0.4	0.4	0.4	0.4	0.4	1.8
Increasing insurance premiums	0.4	0.4	0.4	0.4	0.4	2.2
IT cloud solutions	0.7	0.7	1.0	1.2	1.2	4.7
Security of critical infrastructure	10.1	8.8	8.9	9.0	9.1	45.9
Solar enablement	0.9	0.8	0.8	0.8	0.8	4.2
Category Specific	**6.4**	**6.4**	**6.4**	**6.4**	**6.4**	**32.0**
Communications network	0.9	0.9	0.9	0.9	0.9	4.7
Replacement expenditure on faults and minor repairs	5.2	5.2	5.2	5.2	5.2	26.2
Wasted truck visits	0.2	0.2	0.2	0.2	0.2	1.1
Total	**25.0**	**23.6**	**24.5**	**22.9**	**21.7**	**117.7**

Source: EMCa Analysis of 'UED- RIN001 - Workbook 1 - Reg Determination - 31 January 2020'. Note that this excludes the HBRA-related opex which United Energy originally proposed, but which we understand has been withdrawn.

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

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

Figure 2.9: AER Focus sections of proposed opex step changes - $m, real 2021

Group & Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Step Changes	**1.6**	**1.5**	**1.8**	**2.0**	**2.0**	**8.9**
IT cloud solutions	0.7	0.7	1.0	1.2	1.2	4.7
Solar enablement	0.9	0.8	0.8	0.8	0.8	4.2
Category Specific	**5.2**	**5.2**	**5.2**	**5.2**	**5.2**	**26.2**
Replacement expenditure on faults and minor repairs	5.2	5.2	5.2	5.2	5.2	26.2
Total	**6.9**	**6.7**	**7.1**	**7.2**	**7.2**	**35.2**

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

33. Our assessment of ICT cloud opex is in the ICT section (section 7). 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

34. 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 appropriately references the capital expenditure objectives.

35. 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. In the third criterion, we note the wording of a '*realistic expectation*' (emphasis added). In our review, we have sought to allow for a margin as to what is considered reasonable and realistic, and we have formulated negative findings where we consider that a particular aspect is outside of those bounds;
- We note the wording '*meet or manage'* in the first 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 enhancing or diminishing, the aspects referred to in those objectives

36. 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 United Energy. 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 United Energy's framework

3.1.1 Investment governance and management framework – Overview

37. United Energy describe the network investment framework as applicable to its 'business as usual' annual budget setting process. The network investment framework is used to *'achieve safety, reliability and compliance objectives at least cost.'* [4]

38. During the onsite presentation, United Energy described its capex program governance as comprising: (i) an annual budget and five-year plan; and (ii) program monitoring, as shown in the figure below.

Figure 3.1: Network capital expenditure program governance

Annual budget and five year plan	Annual capital expenditure program monitoring
Bottom up planning • On an annual basis, investments are proposed into C55 in line with the objectives of the relevant lifecycle strategy & plans. We then apply the network investment process to develop the optimal mix of capital investments **Top down reviews** • The capex proposal is then subjected to multiple levels of top down challenges by the GM network and Executive Management Team before finalisation	• A Capital and Operating Works Program (COWP) steering committee meeting is held monthly with senior managers and Executive Team members (GM Network, GM Service Delivery and CFO) • This committee monitors the capital program delivery against targets/budgets and approves changes/variations to the capital program

Source: United Energy onsite review meeting presentation to AER/EMCa

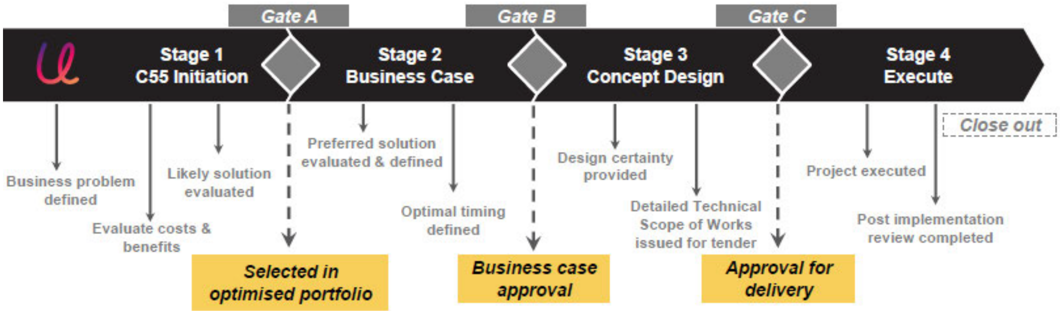
39. The project-level governance increases with the cost of the project, including through a hierarchy of investment committees. The United Energy Board reviews and approves

4 United Energy onsite review meeting presentation to AER/EMCa

expenditure greater than $4.0m. Projects are evaluated and approved after ensuring the technical, commercial and delivery risks are acceptable for the business

40. United Energy follows a capital expenditure project gating process as shown in the figure below.

Figure 3.2: Capital expenditure project gating and re-approval process



Re-approval process

Cost based	-	Detailed estimate or tender price greater than business case value	Accumulation of project variations greater than business case value
Re-approval process	Return to C55	Return to business case stage	Return to business stage for variation; continue contract once project variations are approved

Source: United Energy presentation to AER/EMCa

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

3.1.2 Portfolio optimisation

Overview

42. United Energy states that it uses a value framework to assign value to various benefits to allow ranking of potential investments / projects. This includes investment cost, safety risk, environmental risk, employee utilisation, future capital costs, future operating costs, bushfire risk, customer impact, compliance risk, IT security risk and reliability risk. We understand that United Energy's reference to the value framework is most likely to its use of its optimisation tool, which applies to network capex. We consider non-network capex separately - this is presented in our review of expenditure for each of the non-network capex categories that we assessed.

43. Copperleaf's C55 software (C55) is used by United Energy to optimise both the mix and timing of project expenditure. However, only discretionary expenditure is subject to optimisation.

44. For its regulatory proposal, United Energy developed a bottom-up capex portfolio which was separated into discretionary and non-discretionary expenditure. In response to our request for details of the optimisation process undertaken by United Energy, together with details of which projects were identified as discretionary, United Energy separated its expenditure as shown in the table below.

Table 3.1: Discretionary and non-discretionary expenditure categories

Discretionary (and subject to optimisation)	Non-discretionary (and not subject to optimisation)
• augmentation expenditure that is demand driven • replacement expenditure based on asset condition where there is discretion on timing.	• customer initiated works • replacement expenditure that is inspection based/fault driven • safety driven capital expenditure that meets as far as practicable (AFAP) • capital expenditure works to achieve thresholds of compliance • capital expenditure that has been initiated and is considered 'in-flight'

Source: Response to information request IR031

45. We observe that this list does not reflect all expenditure categories.

46. In its application of the optimisation tool, United Energy advised[5] that it considered two constraints for the expenditure considered as discretionary, neither of which were applied:

- program deliverability – United Energy considered that the annual proposed capital expenditure program (at the aggregate capital portfolio level) could be delivered through its current agreement with its network service provider and existing capital expenditure panel arrangements; and
- financial affordability – United Energy considered that the annual proposed capital expenditure program could be funded.

Top-down review methods

Network investment optimisation is supported by C55

47. On an annual basis, project investments are proposed into C55 to achieve the objectives of the relevant lifecycle strategy and plans or non-asset class strategy and plans. United Energy then applies its network investment process to develop the optimal mix of capital investments, with projects being peer reviewed to challenge the cost and benefits.

48. The annual capital expenditure proposal is then subjected to multiple levels of 'top down' challenges by the General Manager Electricity Network and EMT before finalisation.

ICT investment top-down review included external advice

49. The development of United Energy's ICT capital expenditure forecasts involved several top-down review challenges, which we summarise as follows:[6]

- Executive leadership team – nine expenditure iteration reviews;
- IT leadership team - nine iterations 'including review of the portfolio and timing of projects and the total costs proposed for each project';
- External consultant review - mid-way through the proposal development process (iteration 4), United Energy engaged PwC to '*review our project portfolio and timing, as well as the justification and costing for the business cases';*
- Internal expert review – review of 'models and business cases by relevant IT SMEs and the relevant IT leadership team member'; and
- Customer deliberative forums - on marque projects, including Digital Network, Customer Enablement, and Intelligent Engineering.

5 Response to information request IR031

6 Response to information request IR020 question 3

Property investment review was based on scale and deliverability analysis

50. At our meeting with United Energy, it advised that it tested the bottom-up expenditure forecast by:[7]

- 'Assessing proposed projects against Powercor's historical expenditure (because of shared resourcing), ensuring it was of a similar scale to what we have already delivered'; and
- Assessing its project delivery model (which is based on using third party construction companies to provide flexibility).

Review of Regulatory Proposal forecast

Development of the expenditure forecast

51. United Energy states[8] that its Regulatory Proposal is based on its 'Steady State' planning scenario[9] and aligns with both its current asset management and planning strategies and its current risk management profile.

52. United Energy has established a steering committee ("SteerCo") which consists of all Executive Management team members. The SteerCo is responsible for overseeing projects identified in United Energy's strategic program of works, as determined annually and includes the Regulatory Proposal.

53. United Energy describes that the expenditure forecasts provided in its Regulatory Proposal have been subject to:

- internally conducted 'deep dives' and peer review by expenditure category - deep dives included review by SMEs, General Managers, the Energy Futures Customer Advisory Panel (EFCAP) and the 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.

54. 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

55. United Energy advised that the development of the first expenditure iteration was prepared in June 2018, with a total of nine iterations of its capital program prior to submission of the regulatory proposal.[10] All expenditure iterations were presented to the SteerCo.

56. United Energy describe the role of the SteerCo as having:[11]

> *'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.'*

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7 United Energy presentation to AER/EMCa May 2020_final, slide 31. United Energy refers to Powercor, because of Powercor's current experience with depot re-developments

8 Response to information request IR031

9 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.

10 Response to information request IR031

11 Response to information request IR031

3.1.3 Risk management framework

Overview

57. United Energy has established an Enterprise Risk Management (ERM) 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.

The network risk monetisation model for asset replacement is based on a different approach

58. United Energy has based the development of its risk monetisation methods on redundancy of the system, such that it only models hours at risk over the course of a year where the load exceeds certain levels.

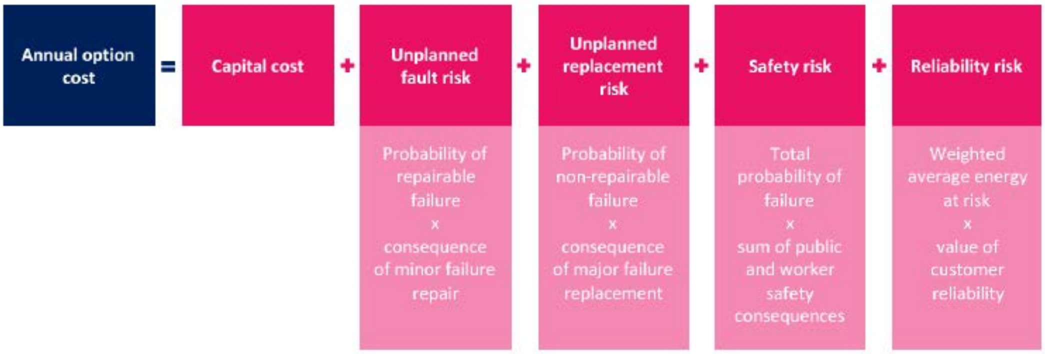
59. United Energy applies its risk monetisation methods to transformers and switchgear replacement decisions. United Energy describes its approach as:[12]

> *'The transformer and switchgear monetisation model (UE MOD 4.04) is underpinned by a Multi-Greek Letter model (MGL), which models the substation as a system of redundant assets in parallel. This is then combined with risks associated with a failure to determine overall asset risk. The approach is documented in our asset risk quantification guide, submitted with our regulatory proposal (UE ATT0139); and*
>
> *We differ from most utilities in that we now model transformers as a redundant system, as distinct from individual assets. This approach is consistent with engineering modelling in other industries, including protection systems.'*

60. United Energy applies a modified version of the risk monetisation model to its services replacement program,[13] overhead conductor and pole top structures,[14] and secondary systems.[15]

61. United Energy has described the calculation of annual asset risk in the figure below.

Figure 3.3: United Energy's calculation of annual asset risk cost



Source: United Energy Regulatory Proposal Figure 4.10

62. United Energy describes the underlying assumptions and principles as being set out in its asset risk quantification guide.[16]

12 Response to information request IR016

13 UE MOD 4.05

14 UE MOD 4.03, project list

15 Response to information request IR013 protection and control monetisation model

16 UE ATT139 United Energy, Asset Risk Quantification Guide

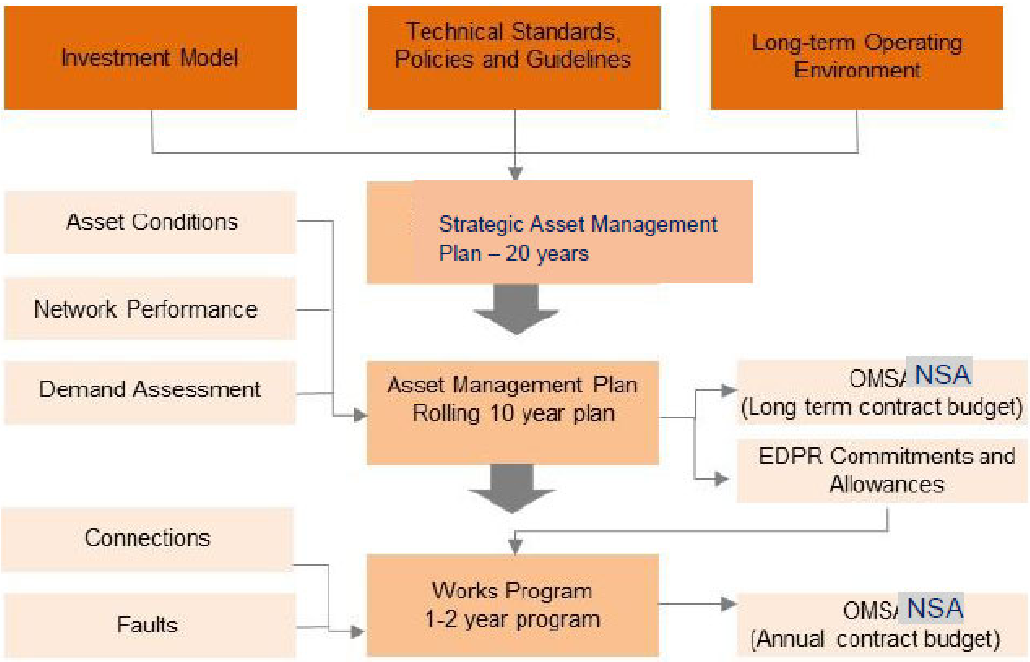
3.1.4 Asset management framework

Overview

63. United Energy describes its Asset Management System (AMS) as encompassing:

'a series of interlocking processes that cover most functions across the business and define how the assets are managed over the long, medium and short term.'[17]

Figure 3.4: United Energy's Asset Management System



Source: United Energy ATT021 Strategic asset management

64. United Energy states that it has established key asset management processes to manage its assets over distinct time horizons:[18]

- 'Asset Management Policy, Strategy and Objectives: these provide our approach to prudently manage assets on a whole-of-life basis and define our long term business assumptions. This includes management of external drivers that may influence our asset management approach;
- Asset Management Plan: a rolling ten year plan of the business' priorities, main projects and expenditure as well as the baseline information for the EDPR and NSA. The Asset Management Plan outlines CapEx as well as the associated OpEx over the ten year time horizon; and
- Works Program: a one-two year program of work which outlines the specific activities and investments that represent the most cost effective approach for executing the Asset Management Plan.'

65. According to United Energy, the structure of its AMS is in accordance with the high-level structure of ISO55001.

Asset class strategies and plans

66. As a part of its AMS, United Energy has developed lifecycle strategies and plans for each asset class. In addition, United Energy has developed non-asset class strategies and plans

[17] United Energy ATT021 Strategic asset management, Figure 4, p15

[18] United Energy ATT021 Strategic asset management, p15

which are representative of the end-to-end performance of the whole network as a complete system and that typically affect multiple asset classes.

Changes to asset management practice

67. Changes to its 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

68. In this section we focus on the expenditure forecasting methods and assumptions at a high level. We outline the specific aspects of United Energy's expenditure forecasting methodologies for each of the expenditure categories that we reviewed[19], along with our assessment of these methodologies as part of our assessment of each expenditure category.

Expenditure justification

69. 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 3.2: Proportion of expenditure included in business case documentation

Expenditure 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

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

71. 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

72. In its Regulatory Proposal, United Energy states that its historical costs reflect its outsourced operating model, where all capital works are undertaken by independent, third-party service providers following an open, competitive tender. Also, for major projects, the work is delivered from a panel of suppliers who compete for work via a tendering process.

73. United Energy considers that historical costs provide a reasonable basis for forecasting network-related costs for the next RCP:[20]

> *'As one of the most cost-efficient distributors in Australia, based on AER benchmarking, we consider our historical costs provide a reasonable basis for forecasting future investment requirements.'*

74. For network-related expenditure, United Energy has:[21]

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

20 United Energy Regulatory Proposal page 69

21 United Energy Regulatory Proposal p107

'…forecast costs for capital projects based on recent historical costs for efficiently delivered projects of similar scope, size and geographic locations. These costs reflect our outsourced operating model, where all field works are undertaken by independent, third-party service providers following an open, competitive tender.'

75. Specifically, for repex, United Energy states:[22]

- 'For high-volume, low value assets, these costs are typically determined as the average over the period 2015–2018; and
- For low-volume, high-value assets, we typically forecast costs based on recent efficiently delivered projects of similar scope, size and geographic location.'

76. United Energy's ICT project costs are derived from bottom-up assessment of scopes of work and the labour, contract and materials components are based on:[23]

- Labour rate - Blended IT labour rates developed by PWC. Crossed checked against internal aggregate labour rate;
- Labour hours - Hour incurred for like projects of similar size and complexity;
- Contracts -Vendor charges for like projects of similar size and complexity, or specific quotes where available; and
- Materials - Current unit rates or supplier quotes.

Deliverability

77. United Energy describe three mechanism to deliver its network-related investment plans:[24]

- **'Long-term contracts**: UE has a contract (NSA) in place with a service provider: Zinfra. This service provider carries out routine maintenance and small CapEx construction activities under a performance incentive based contract within UE network. The contract is effective from late January 2018 for the next 3 years. It may be extended for 1 year twice after January 2021 at UE's discretion;
- **Projects to tender**: for capital works in addition to the regular contracted work, UE has the ability to access NSA contractor or go to market and ask various parties to tender for the work. This could be either through the existing single service provider, or in some cases new service providers. To help facilitate this process, the Works Program packages up projects to enable benefits to be obtained through tendering significant sized projects. Projects that are suitable to be tendered as turn-key projects are identified at conception stage and a detailed scope of works is prepared as the basis for tender documents; and
- **Approved materials schedules**: UE has developed and maintains schedules of materials approved for installation on the network with which all contractors must comply as part of its health, safety and environment systems. This ensures that the integrity of the network assets is maintained and that purchasing and stockholding procedures are stream-lined.'

78. United Energy's ICT program is delivered via a similar process to that described above for the network program:[25]

'A key way we are able to deliver large projects while minimising associated projects risks and costs is through vendor support and third party contractors. Through careful planning, we can ramp up resources when a project's workload peaks, before returning labour to normal levels as the project scales down. This is especially advantageous in delivering large-scale IT projects…'

22 United Energy Regulatory Proposal page 69

23 United Energy presentation to AER/EMCa May 2020_final, slide 30

24 United Energy ATT021 Strategic asset management, p21

25 United Energy Regulatory Proposal page 122

79. 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, United Energy states that its outsourced model allows it to:

> *'deliver the total capital program including forecast increase in investment over the 2021-2026 regulatory period, by using resources in the open market.'* [26]

80. Further, United Energy states that:[27]

> *'we also have a demonstrated history of delivering large and complex capital programs, including during the 2011-2016 regulatory period (i.e. the value of our replacement program was consistent with that forecast in the 2021-2026 regulatory period, once our environment spend is removed), and the roll-out of advance metering infrastructure.'*

3.2 Assessment of United Energy's framework

3.2.1 Risk management

Risk framework is generally consistent with industry practice

81. The risk framework at the enterprise level is consistent with industry practice, along with the establishment of risk appetite statements.

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

82. United Energy refers to including projects on the basis of meeting its obligations to minimise risk as far as practicable (AFAP), following either a scheduled or ad hoc AFAP risk review to identify changing or emerging risks.

83. United Energy claims that its AFAP processes and assumptions are consistent with its risk quantification guide. We have therefore looked for evidence of how United Energy has demonstrated that the project should proceed on the basis of AFAP, including through use of its risk models and cost-benefit analysis.

Application of risk assessments to asset replacement decisions

84. With the exception of those relatively confined categories where risk monetisation models have been applied[28] and were provided to us for review, application of risk management is not clearly evident to the balance of United Energy's forecast expenditure. Instead, United Energy seems to have prepared its forecast primarily on the basis of continuing existing asset management practices.

3.2.2 Risk monetisation

Reasonableness of applied method for repex

85. United Energy states that its risk monetisation approach:[29]

> *'.. identifies the least-cost solution to manage the substation, based on the identified failure modes for an asset, and the corresponding probabilities, likelihoods and consequences of failures. This approach is consistent with the AER's recent asset replacement practice note.'*

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26 Response to information request IR016

27 Response to information request IR016

28 For transformer and switchgear asset replacement decisions

29 United Energy BUS 4.03 - Transformer replacement - Jan2020 - Public

86. For example, United Energy states that it has developed its transformer replacement program through risk monetisation analysis that identified the least-cost solution to manage each substation, based on the identified failure modes for an asset, and the corresponding probabilities, likelihoods and consequences of failures.

87. The approach appears to be driven at a 'whole of substation' level. This could mean that individual transformers are being replaced whilst there is remaining asset life. It could also mean that a single component could be driving the timing for replacement of all other components.

88. While noting the potential issues that could arise from applying the methodology at a whole of substation level, we consider that the approach adopted by United Energy is essentially consistent with the AER practice guide.

Different approach to estimating and managing asset failure risk in substations

89. United Energy states that: [30]

> *'the probability of failure is a key input assumption in any risk monetisation model…… Since 2018, we have quantified transformer failure risk based on the overall risk at the zone substation.'*

90. By undertaking its assessment at the zone substation, rather than based on the condition of individual assets in isolation, United Energy states that this has allowed it to reduce outage response times and to manage transformers towards failure (where safe). This approach, including investment to prepare sites to accommodate a relocatable transformer, appears to have allowed the deferral of some transformer replacements in the current regulatory period.

91. An Asset Health Indicator is then used to prioritise which assets are replaced at the zone substation.

Probability of failure based on limited failure data

92. The historical asset failure rates used as the basis for calculation of a probability of failure are based on United Energy's own internal data, which is limited due to the low level of historical failures observed. United Energy have then supplemented its internal data with failure data from other Australian distributors, or from recognised international sources (e.g., Ofgem data).[31]

93. For zone substation assets, where some level of asset redundancy exists, United Energy consider a conditional probability of failure. This approach recognises common-cause failure(s) due to elements common to multiple assets. These elements may include similarities in design and construction, maintenance practices, operating duty, age or condition, and geography.

94. United Energy has provided an independent review of its transformer fleet which indicates the presence of a number of issues, including: [32]

> *'What is evident from the data presented in the supplied transformer incident investigation reports, is that United Energy has a number of transformers that have a higher than normal potential of failure. This is due in part to the substation bus protection schemes which allowed the identification of inherent weaknesses in the original transformer designs.'*

95. Based on our review of the provided data, which was limited to 14 significant events over seven years, only two failures were windings. The main driver of these failures was related to failures of bushings and tap changers. This appears to suggest that preventive maintenance might have avoided these failures - the need for whole transformer

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30 UE BUS 4.03 - Transformer replacement - Jan2020 – Public, page 8

31 UE Regulatory Proposal page 69

32 UE ATT198 - K-BIK - Power substation failures review - Jan2020 – Public, page 17

replacements is not clear. We explore this further in our review of the corresponding replacement expenditure.

Value of VCR is not weighted to customer mix at the substation

96. The VCR value used in United Energy's model is based on the 2014 AEMO values, escalated to current value. United Energy uses a state-wide value and not values derived for the customer mix at each substation site. The use of a VCR value that reflects the customer mix at the zone substation is more reflective of the impact to customers and is likely to have a material impact to the forecast. We include this in our sensitivity analysis in the assessment of expenditure.

97. United Energy has not applied the AER values of VCR. Although these are lower, the values are unlikely to have a material impact on the forecast. United Energy stated that it will update its risk quantification modelling for the AER's recent VCR decision, along with other relevant factors, as part of its revised proposal.[33]

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

98. 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.

99. We asked for an explanation of this approach, applied to both repex and augex, during the onsite discussions with United Energy and in our requests for information. In summary, United Energy replied that:

- It's mathematically incorrect that the 50% PoE represents a realistic expectation of demand;
- Considering only the 50% PoE would increase the risk of asset failures and would not allow it to maintain the safety of the system;
- It would lead to a decline in reliability;
- The Code requires DNSPs to have regard for lower probability events; and
- If not applied to all Victorian distributors, it would establish different planning standards in Victoria.

100. United Energy also makes reference to AEMO using a weighted average of 50% and 10% PoE values in regard to a RIT-T.

101. We consider the key issue here is the application of a planning methodology to estimate the expected value of unserved energy. We consider that United Energy is incorrect in stating that the 50% PoE does not represent a realistic expectation of demand. However, 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.

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

103. We consider that other elements of the explanation that United Energy has provided are not directly relevant to the objective of reliability-based justification for investment. This includes United Energy's reference to safety impacts and the need to have regard for lower probability events. We concur that it would not be desirable for different standards to apply to different DNSPs, however it appears that it is already the case that Victorian DNSPs apply a method that differs from the rest of Australia.

[33] Response to information request IR031

104. 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.

3.2.3 Asset Management

Moving to an integrated approach should assist with decision making

105. During the onsite discussion, United Energy presented its plans to develop an Integrated Network Management System (INMS), to amongst other things, enable United Energy to efficiently meet multiple management system standards. This is achieved by combining a number of management systems into the INMS, including:

- Asset Management System (AMS);
- Electricity (Network) Safety Management System (ESMS);
- Occupational Health and Safety Management System (OHSMS); and
- Environment Management Framework (EMF).

106. The INMS reflects areas of the business related to the electricity network and excludes corporate functions.

107. Development of the INMS is likely to address potential areas of duplication across individual management systems and assist United Energy to identify further areas for improvement and associated efficiencies in its business processes.

United Energy states that it is taking steps to manage future uncertainty

108. United Energy states that:[34]

> *'In response to future uncertainty, UE is evolving its asset management approach to manage the network more efficiently and stretch existing assets to their full capability.'*
>
> *'This approach is currently being demonstrated by our management of zone substation equipment, with replacement starting to be delivered one asset at a time rather than in bulk, until such time [as] the demand justifies replacement of subsequent parallel assets.'*

109. We looked for evidence that United Energy was effectively accounting for uncertainty, both in the role and duty of the current distribution network.

110. United Energy states that its asset management approach has shifted from a program based on individual asset condition and future load forecasts for 2016-2020. Its current asset management practice and forecast methods, and which United Energy has applied for the next RCP, is now focused on managing overall zone substation risk.

111. Undertaking sensitivity analyses is one way of managing uncertainty by testing the robustness of the proposed approach and timing of the preferred investment. In projects for which United Energy says that it undertakes sensitivity analyses, it considers only the result on the ranking of the options from varying some of its input assumptions including the demand forecast, assumed discount rates, and the capital and operating expenditure forecasts.

112. For parts of its capex forecast, United Energy does not appear to explicitly consider the impact on the economically optimum timing of the work as part of its sensitivity analysis.

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[34] United Energy ATT021 Strategic asset management, p43

Asset lifecycle strategies are fit for purpose

113. United Energy describes that its lifecycle strategies define the specific approach to, and principles for, the safe and efficient management of each asset class including the strategies for lifecycle management

114. In general, we found that these documents assisted our understanding of the approach taken for management of each asset class, when considered alongside the business case documents and risk models that were provided to us.

115. For its volumetric programs, the forecasts are based on actual replacement volumes and are generally not supported by business case documents or risk models. In these cases, United Energy consider that the replacement volumes are:[35]

> *'a direct reflection of our asset life-cycle strategies and asset inspection manuals. These asset life-cycle strategies are subject to periodic reviews to ensure they remain current, and to date, have allowed us to maintain robust and consistent performance outcomes.'*

116. We considered the reasonableness of United Energy's application of life cycle strategies and forecasting approach as a part of our assessment of expenditure.

Non-asset strategies have not been considered in our review

117. On advice from United Energy that its non-asset strategies have not materially contributed to forecast replacement expenditure,[36] 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

118. In its documentation, and supported by the onsite discussion, the performance indicators for reliability and safety are generally improving. This is in part due to the improved asset management approaches and targeted programs undertaken by United Energy in previous years.

119. In response to our question regarding improved customer service outcomes, United Energy states that:[37]

> *'For the purpose of the regulatory reset, we only include expenditure that maintains network reliability; and*
>
> *In terms of network safety and bushfire, we only consider it prudent and practical to reduce these safety risk in cases where the costs of doing so are not grossly disproportionate to the benefits.'*

120. Where the proposed expenditure is proposed to deliver a benefit, United Energy claim that this has been clearly identified in its Regulatory Proposal and supported by a cost-benefit analysis. We have taken into account the cost-benefit analysis and other supporting information provided by United Energy in our assessment of expenditure.

121. Since the level of network and customer risk is not static in an electricity system, we have reviewed how United Energy has considered the changing level of risk and performance trends in developing and optimising its forecast expenditure for the next RCP. We have not seen evidence that this analysis was undertaken at the portfolio level

35 Response to information request IR031

36 Response to information request IR031

37 Response to information request IR031

United Energy's portfolio optimisation is limited

122. In its onsite presentation, United Energy described the use of its Copperleaf C55 software (C55) to optimise both the mix and timing of network project expenditure. However, only discretionary expenditure is subject to such optimisation and the classification of network expenditure does not appear to include all network expenditure categories.

123. We sought further clarification on the scope and application of the optimisation model for the forecast. United Energy provided the following additional information:[38]

> *'..our network investment framework is applicable to our 'business as usual' annual budget setting process. The development of regulatory reset expenditure forecasts is [sic] must be different given the timeframes and level of external scrutiny applied to our forecasts.'*

124. The optimisation tool described by United Energy is limited to review of discretionary projects only and excludes a large proportion of the proposed forecast expenditure. We were not provided with information as to the operation of the tool and find it difficult to ascertain how the portfolio could be optimised given that it does not consider all components of the program.

125. Similarly, we did not see evidence of prioritisation of the portfolio to address the highest areas of risk, or where the program had been modified in response to the optimisation of proposed projects and programs. As discussed in our assessment of proposed expenditure, we found examples that indicate to us that there is further opportunity to prioritise existing projects and programs to target the highest areas of risk.

126. United Energy's approach to reviewing its ICT portfolio is consistent with industry practice. However, we did not see evidence of the progressive refinement from the initial bottom-up capex (and opex) to arrive at the proposed amount for ICT, or other parts of its capex forecast.

Projects are at an early stage of development

127. 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.

128. 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 inherent nature of a forecast, in our assessment of expenditure we sought to understand: (i) the changes made by United Energy through its iterative process of approval; (ii) the sensitivity analysis undertaken to inform investment decisions; and (iii) the consideration of option value in the risk analysis that was undertaken.

Full impact of cost efficiencies not evident in forecast

129. United Energy has described that during the current RCP, it has delivered capex savings of $199.8m[39] through three broad approaches:

- making efficient investment decisions;
- renegotiating service provider contracts through market testing; and
- realising synergies by moving to joint provision of corporate services with CitiPower and Powercor.

130. 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 its forecast expenditure for the next RCP.

131. In its response, United Energy states that:[40]

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38 Response to information request IR031

39 United Energy APP02 What we have delivered

40 Response to information request IR031

'Of most relevance to replacement expenditure efficiencies was the renegotiation of service provide contracts for major works and field services. These savings negotiated over the period 2017-2018 realised savings in the order of 7.5-10% on previous unit rates and project costs. These savings are now reflected in our audited historical costs for the current regulatory period. They are integrated into the unit rates used to forecast our 2021-2026 expenditure;

[redacted] *and*

Other aspects of our efficiencies relevant to replacement expenditure have been the efficient deferral of capital expenditure through improved risk modelling and investing in our zone substations to accommodate mobile transformers. As discussed in the forecasting methodology session, these changes are 'business as usual' and are incorporated in our forecasting methodology.'

132. In our assessment, we therefore looked for evidence that these efficiency savings had been incorporated into the unit costs applied by United Energy in the development of its forecast expenditure.

133. We observed that, whilst the savings negotiated over the period 2017-2018 and which realised savings in the order of 7.5-10% on previous unit rates and project costs are likely to have been passed on, the method applied by United Energy to calculate the unit rates for the forecast period also includes higher historical unit rates.

134. Further, we found examples whereby the composition of work, volume or recency are likely to provide further opportunities for efficiencies for some work types that do not appear to have been taken into account in other aspects of the forecast expenditure for major projects.

135. In other cases, United Energy has reproposed projects for the next RCP that were deferred from the current RCP, albeit incurring lower cost solutions in some cases to mitigate the risk. The example projects provided,[41] have been included with a value of capex that is lower than initially proposed for the current RCP.

136. Based on the information provided by United Energy, we are not convinced that the full capital efficiencies which have been achieved in the current RCP have been adequately reflected in the costs relied upon for developing the forecast expenditure for the next RCP.

3.3 Summary of findings

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

137. The elements of the governance and management framework described to us by United Energy are generally consistent with industry practice. We have been largely guided by discussions with United Energy and the description provided of the review and engagement processes conducted as part of development of its Regulatory Proposal and expenditure forecast.

138. We have focused our assessment on United Energy's application of each of these elements in developing and reviewing its expenditure forecast for the next RCP, and based on the evidence provided from our assessment of the aspects of capex and opex within our scope.

139. As discussed in sections 4 to 8 for capex, and section 9 for opex, we have concerns with the practical application of certain elements of United Energy's governance and management framework and application of its forecasting processes to actual projects and programs.

[41] United Energy APP02 - What we have delivered, Table 6 and Table 7

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

140. We observe that the approach taken by United Energy 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 United Energy has effectively established a link between its proposed program(s) and intended benefit to consumers - including as measured by network performance outcomes and network risk indices.

141. At a portfolio level, we observe that United Energy 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 the forecast expenditure for the next RCP.

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

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

143. We have outlined the specific aspects of United Energy's expenditure forecasting methodologies,[42] along with our assessment of these methodologies, for each of the expenditure categories that we reviewed.

United Energy has declared significant efficiencies in the current period, but do not appear to have accounted for these in their forecasts

144. We have not seen sufficient evidence that cost efficiencies declared by United Energy in the current RCP have been reflected in its forecast expenditure for the next RCP. This is consistent with the observation that United Energy has considerably underspent its capex allowances in the current period. Accordingly, we consider there is potential for further cost efficiencies to be accounted for in their proposed capex allowances, on the basis that the full impact of realised cost efficiencies do not appear to have been fully reflected in unit costs, or the method applied to derive the unit costs.

Our assessment of Governance and Management frameworks and forecasting methodologies is specific only to certain aspects of United Energy's forecast

Our assessment is specific only to the certain aspects of United Energy's expenditure that is included in our scope of review. In sections 4 to 9 of this report, we consider United Energy's application of its governance and management frameworks and expenditure forecasting methodologies to the relevant capex and opex categories.

42 Repex, augmentation (non-DER and DER driven), ICT, and property

4 REVIEW OF PROPOSED REPEX

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

We consider that United Energy' proposed repex is not a reasonable forecast of its requirements. We consider that its proposed expenditure allowance for wood pole replacements is considerably overstated and that elements of its proposed expenditure on service lines, pole top structures, transformer, switchgear, and SCADA categories are also overstated (though to a lesser degree).

We consider that United Energy's proposed repex for its overhead conductor, underground cable and 'other' repex categories are reasonable.

We consider that United Energy'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

145. We reviewed the information provided by United Energy 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.

146. We sought to establish the strategic basis for, and the reasonableness of, United Energy's proposed repex for each of the identified categories of expenditure. We note that the expenditure in the next RCP is reflective of a step increase from the historical expenditure that United Energy has incurred and is expected to incur in the current RCP.

147. United Energy has provided its bottom-up forecast and described how this forecast has been apportioned to each of the RIN categories. We have referred to this in our assessment.

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

149. We first summarise and compare United Energy'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 United Energy's forecast for each repex RIN group.

4.2 Summary of United Energy's proposed repex

4.2.1 Overview

150. United Energy's repex forecast originally proposed in its regulatory submission is $504.9m for the next RCP. As described in Section 2, United Energy subsequently withdrew and substituted the Environmental Management program.

151. Table 4.1 shows our assessment of the proposed Repex by RIN Group following this adjustment.

Table 4.1: United Energy repex for the next RCP with Environmental Management program removed - $m, real 2021

Group	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Poles	16.9	18.1	19.1	19.4	20.5	94.0
Pole Top Structures	15.1	15.3	15.5	15.8	16.0	77.7
Overhead Conductors	3.0	3.1	3.1	3.1	2.9	15.2
Underground Cables	5.6	5.8	6.3	6.5	6.3	30.6
Service Lines	5.1	5.1	5.0	4.9	4.8	24.9
Transformers	8.6	9.5	10.2	10.0	9.6	47.8
Switchgear	13.4	14.7	15.8	15.2	14.6	73.7
SCADA, Network Control and Protection	7.9	11.5	7.6	10.1	6.5	43.7
Other	2.1	2.6	3.1	2.6	1.8	12.2
Total	**77.8**	**85.6**	**85.8**	**87.7**	**82.9**	**419.8**

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

4.2.2 Repex from the project models as mapped to RIN Groups

152. Table 4.2 below shows project-level of $403.1m for the next RCP. We also show the AER focus projects and relevant amounts. The Environmental Management program has been removed, consistent with the table above.

153. Real cost escalation has not been included in United Energy'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: United Energy repex for next RCP, as amended by UE, showing AER Focus Projects and Programs - $m, real 2021

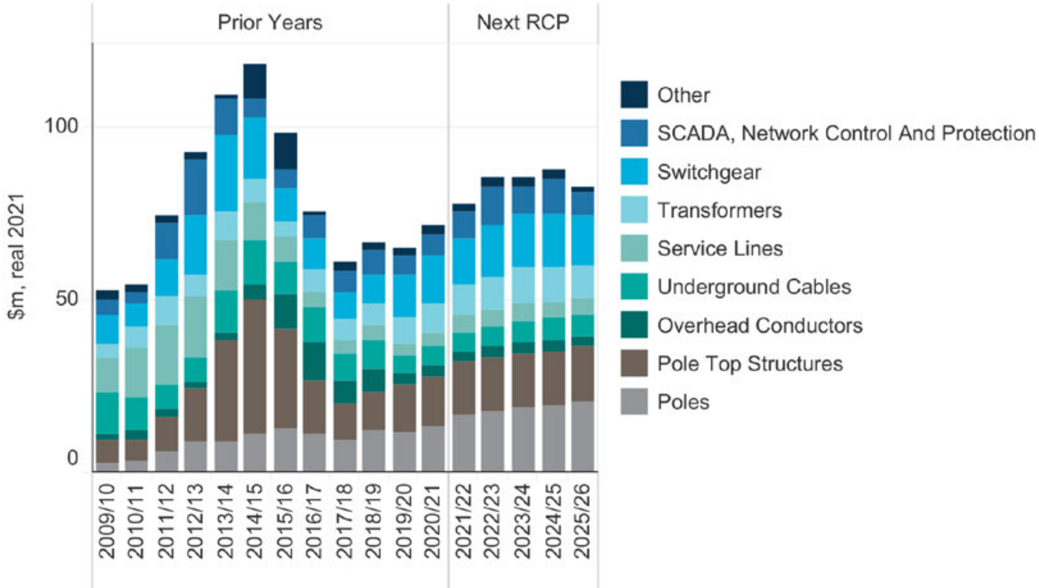
Group / Focus	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Poles	16.7	17.6	18.4	18.4	19.2	90.2
Focus: Pole Replacements program	*16.7*	*17.6*	*18.4*	*18.4*	*19.2*	*90.2*
Pole Top Structures	14.9	14.9	14.9	15.0	14.9	74.6
Overhead Conductors	3.0	3.0	3.0	3.0	2.7	14.6
Underground Cables	5.5	5.6	6.1	6.2	5.9	29.3
Focus: ZS Transformers & Switchgear	*1.2*	*1.3*	*1.2*	*1.4*	*1.6*	*6.7*
Other	*4.3*	*4.4*	*4.8*	*4.8*	*4.3*	*22.6*
Service Lines	5.1	4.9	4.8	4.6	4.5	23.9
Focus: Service Lines	*5.1*	*4.9*	*4.8*	*4.6*	*4.5*	*23.9*
Transformers	8.5	9.2	9.7	9.5	9.0	45.9
Focus: ZS Transformers & Switchgear	*3.4*	*3.9*	*4.6*	*4.9*	*4.6*	*21.4*
Other	*5.1*	*5.4*	*5.2*	*4.6*	*4.4*	*24.5*
Switchgear	13.2	14.3	15.1	14.4	13.7	70.7
Focus: ZS Transformers & Switchgear	*2.6*	*3.3*	*3.8*	*3.5*	*3.4*	*16.6*
Other	*10.6*	*11.0*	*11.3*	*10.9*	*10.3*	*54.1*
SCADA, Network Control and Protection	7.8	11.2	7.3	9.6	6.1	42.0
Focus: SCADA	*7.2*	*10.5*	*6.5*	*8.8*	*5.3*	*38.3*
Focus: ZS Transformers & Switchgear	*0.6*	*0.7*	*0.8*	*0.8*	*0.8*	*3.7*
Other	2.0	2.5	3.0	2.5	1.7	11.9
Focus: ZS Transformers & Switchgear	*0.4*	*0.7*	*1.0*	*0.8*	*0.5*	*3.4*
Other	1.7	1.9	2.0	1.7	1.3	8.6
Total	**76.8**	**83.3**	**82.3**	**83.1**	**77.7**	**403.1**

Source: EMCa analysis of UE IR 34 Response 'AER IR034 - UE MOD 4.03 - mapping reconciliation V1.0'. All values exclude real cost escalation. Excludes Environmental Management program.

4.2.3 Repex trend

154. 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 forecast values for the Environmental Management program have been removed. All expenditure has been inflated to Real 2021 dollars and includes real cost escalation.

Figure 4.1: United Energy repex trend as amended by United Energy (after withdrawals) - $m, real 2021



Source: EMCa analysis of 'United Energy - RIN001 - Workbook 1 - Reg Determination - 31 January 2020', 'United Energy - RIN008 - Workbook 8 - Historical FY CAT - 31 January 2020', 'UE consolidated RIN – Repex'. Excludes Environmental Management program

4.2.4 Observations from Repex trend

155. The figure above shows that United Energy's replacement expenditure has reduced significantly from a peak in 2014/15. Over the last five years, the trend is relatively flat. However, the forecast for the next RCP shows a step increase on an annual average basis for the next \RCP with proposed increases across most expenditure categories.

4.3 Assessment of United Energy's repex activity forecasting methods

4.3.1 Overview

156. In accordance with its asset management framework and asset management system, United Energy forecasts asset replacement volumes based on two broad approaches:[43]

- risk modelling/monetisation; and
- historical volumes and trends.

157. United Energy describes its application of these forecasting approaches to different asset and sub-asset categories based on the characteristics of the underlying asset. For example, high-volume, low-cost assets are typically forecast using observed historical trends (adjusted for any known change in operational policy or asset specific issues) or based on historical replacement volumes. In contrast, low-volume, high-value assets are typically forecast based on individual risk assessments and options analysis.

158. Low-volume, high-value assets are forecast using United Energy's plant, station and lines replacement model whereas high-volume, low-cost assets are forecast using United Energy's unitised volume model.

[43] United Energy Regulatory Proposal

4.3.2 Historical volumes and trends using unitised volume model

Unitised volume model

159. United Energy has developed a unitised volume model, where the:[44]

> *'…replacement volume forecasts for these asset categories are estimated based on a combination of linear trends and historical average volumes. These trends and historical averages are typically based on the previous five years of data, unless asset management changes have occurred that render more recent periods appropriate.'*

160. The unitised volume model applies to high-volume, low-cost asset interventions, with many of these assets replaced using a 'find-and-fix' asset management approach.

161. Each of the asset categories are assigned a function code, typically consisting of three letters. For example, HV pole replacement is designated as 'RPH'. As described by United Energy, for each function code, the forecasting method for volumes is typically an average of the historical data.

162. For some assets, a linear trend is used to forecast replacement volumes. United Energy first undertakes linear regression analysis of the calibration (sample) period,[45] which varies from between 4 years and 9 years. Where the coefficient of determination[46] is greater than 0.33, a linear method of forecasting replacement volume is applied. Otherwise, an average is applied.

163. We asked United Energy how it determined the calibration period to include in the linear trend and average forecasting methods. United Energy stated that:[47]

> *'The principle behind the sample period used for linear trending is that a longer period is preferred where there is stability in the asset management practices for these assets and/or the underlying age profile, and we have confidence in the sustainability of the data. The outcomes of linear trends are then reviewed to ensure the forecasts are practicable—for example:*
>
> – a default period of five years is applied, and increased where this improves the coefficient of determination (e.g., for our pole replacement material codes—RPRH, RPRL and RPRS—a longer time period increases the robustness of the forecast, which is expected given the relative stability in the underlying asset management and inspection practices);
>
> – a minimum coefficient of determination threshold (0.33) is applied, to support the robustness of the trending relationship (noting that as discussed in response to part (ii) of this question, our forecast is not sensitive to increasing this threshold);
>
> – trending that reduces volumes to zero, or result in strong uplifts, are further reviewed in the context of our asset population (e.g., a trend that reduces volumes to zero, when the corresponding asset population is non-zero, may not be sustainable or realistic); and
>
> – where a simple historical average approach is applied, our starting point is to align with the AER's standard approach in its repex model and adopt a four-year averaging period. We amend these periods, however, where asset management practices have changed and the impact of this change means that a longer period is not expected to be reflective of future intervention volumes.'

44 United Energy Regulatory Proposal, page 63

45 The calibration period is a range of data less than or equal to the available date. This is nominated in the unitised volume model

46 A measurement used to explain how much variability of one factor can be caused by its relationship to another factor (also referred to as "R-squared" or the "goodness of fit")

47 Response to information request IR031

164. We have observed in United Energy's models that the calibration period for the average method varies from the United Energy default period of 4 years, down to 1 year.

165. We have also observed that the selection of linear trend, or averaging period, can be over-written in United Energy's models on the basis of: (i) changes in asset management policy; (ii) limited history available; (iii) step change in volume observed; or (iv) a linear trend that would otherwise decline to zero and not be practicable.

166. Forecast volumes for 2019 onwards are expressed as calendar years and are based on a calibration period that is also in calendar years. The replacement volumes for the forecast period are determined as the average of two adjacent calendar years.

167. Unit rates applied to high-volume, low-cost assets are based on an average over the period 2015–2018 and, when multiplied by the forecast replacement volumes, determine the forecast expenditure.

Variation to the unitised volume model for Poles and Pole-top structures

168. For poles and pole-top structures, a variation to the above approach is used, based on a wider calibration period. For poles, this includes 9 years of historical data. When asked how the sample period in terms of number of years had been determined, United Energy states:[48]

> *'The principle behind the sample period used for linear trending is that a longer period is preferred where there is stability in the asset management practices for these assets and/or the underlying age profile, and we have confidence in the sustainability of the data.'*

169. United Energy considers that a longer time period increases the robustness of the forecast, which is expected given the relative stability in the underlying asset management and inspection practices.

170. In addition, the function codes used for pole reinforcement and pole replacement are separately identified, and further separated by voltage as shown in the table below.

Table 4.3: United Energy function codes for Poles by voltage and intervention type

	Low Voltage (LV)	High Voltage (HV)	Sub-Transmission (ST)
Replacement	RPL	RPH	RPS
Reinforcement	RRL	RRH	RRS
Combined	RPRL	RPRH	RPRS

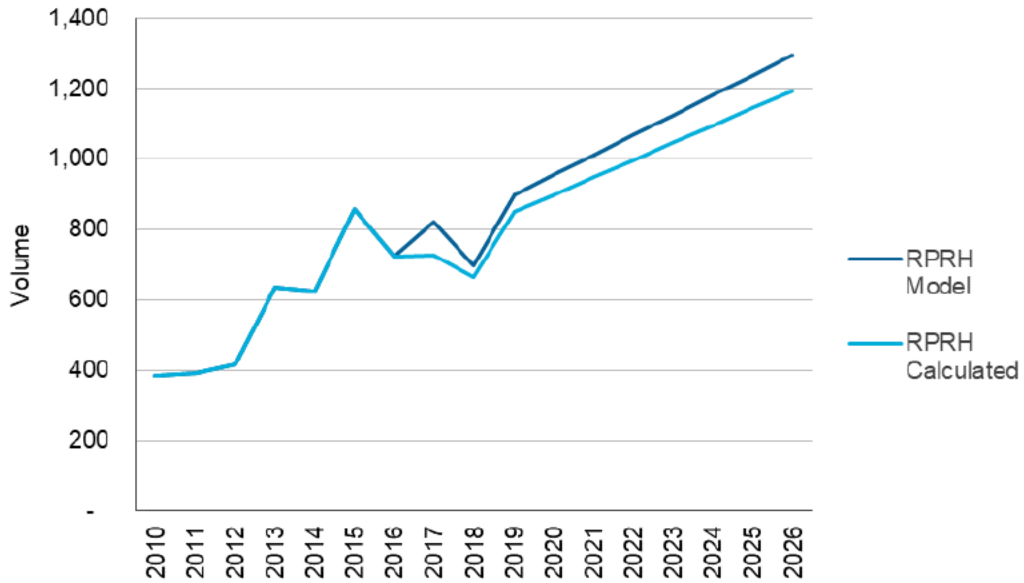
Source: United Energy MOD 4.02 Unitised volume model

171. To develop a basis for calibration of the forecast replacement volumes, United Energy first combines the historical volumes for replacement and reinforcement for each voltage class into a combined function code. The linear regression analysis and averaging is first applied to the combined volumes by voltage class. For example, the volumes for RPH are added to the volumes for RRH in each year and designated as RPRH.

172. The process is hard-coded in the unitised volume model. When we add the RPH and RRH volumes outside of the model and use these calculated volumes to forecast volumes of pole replacement and reinforcement we find a difference for HV and LV poles. We show the difference for HV poles in the figure below. United Energy's hard-coded 'Model' total of pole replacement and reinforcement volumes is higher than our 'Calculated' results, which results in a higher forecast for the next RCP.

48 Response to information request IR031

Figure 4.2: Review of HV poles treatment volume calculations by calendar year



Source: EMCa analysis of United Energy MOD 4.02 Unitised volume model

173. We found a similar discrepancy with pole-top structures. Whilst an averaging method is selected for pole-top structures due to a 'change in asset management policy' and which ignores the effect of much higher replacement volumes that occurred prior to 2017, there is still a difference in volumes between our calculations and United Energy's model data. United Energy also apply a multiplier of 118% to its cross-arm replacement volumes due to what it considers to be lower than a sustainable level of cross-arm replacements in these years.[49]

174. Once the forecast volumes are derived for the combined function codes (e.g., RPRH) the separate function codes for pole replacement and reinforcement are calculated by multiplying an assumed replacement and reinforcement rate included in the unitised volume model. The origins of the assumed rates have not been provided.

175. We compared the reinforcement rates for each of the voltage classes based on the disaggregated data provided in its unitised volume model, with the assumed reinforcement rates as shown in the table below.

Table 4.4: United Energy's pole replacement and reinforcement rate assumptions for each voltage class

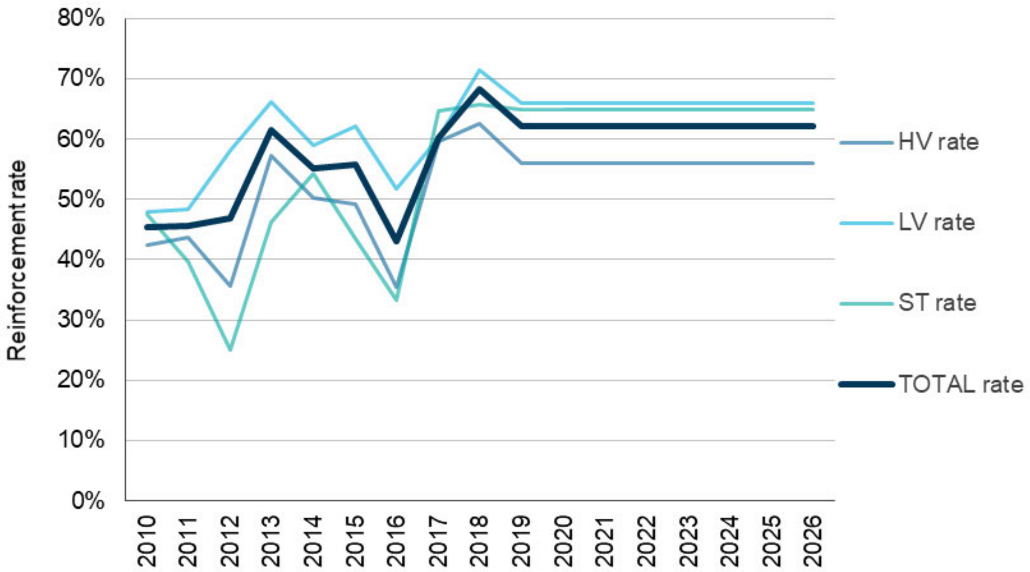
	LV	HV	ST
Replacement	34%	44%	35%
Reinforcement	66%	56%	65%

Source: United Energy MOD 4.02 Unitised volume model

176. As shown in the figure below, the data indicates an increase in reinforcement rates being achieved in the most recent years up to and including 2018, which for LV poles was above 60%. For the 2019 estimate and beyond, the assumed reinforcement rates indicated in Table 4.4 are applied. Whilst these values are generally higher than the long-term average, United Energy has achieved higher HV and LV pole reinforcing rates in 2018 (and 2017 for LV poles).

49 Response to information request IR013

Figure 4.3: Comparison of observed versus assumed pole reinforcement rates



Source: EMCa analysis of United Energy MOD 4.02 Unitised volume model

177. The expenditure forecast is heavily reliant on the unitised volume model which is very sensitive to the calibration data and forecasting method selected by United Energy. We consider the implications of these assumptions as part of our assessment of the proposed expenditure.

178. We asked United Energy to explain what level of justification or supporting information (e.g., a business case) it prepared for the volumetric repex programs included in the next RCP. United Energy stated that:[50]

> *'Our volumetric replacement programs are not subject to business cases. However, as our forecasts are based on actual replacement volumes, they are a direct reflection of our asset life-cycle strategies and asset inspection manuals. These asset life-cycle strategies are subject to periodic reviews to ensure they remain current, and to date, have allowed us to maintain robust and consistent performance outcomes.'*

4.3.3 Risk modelling/monetisation

179. United Energy provided a summary of its forecasting methods, which includes a series of risk-monetisation models, in addition to its unitised volume model for historical volumes and trend-based replacement volumes.

Application to concrete poles and service lines

180. United Energy provided two risk models for expenditure associated with concrete poles and for service lines. The models include failure rates, failure costs and options for treatment (opex & capex) based on United Energy's assessment of least lifecycle cost. We have reviewed these models as part of our assessment of the forecast expenditure.

Output from wood pole models is not provided

181. In addition to the unitised volume model and concrete pole forecasts, United Energy has included a component of its forecast expenditure for wood poles that is derived from Powercor's wood pole forecasting model. United Energy provided data for its class 3 durability poles to Powercor. The output of Powercor's model was adopted by United Energy as an additional volume of pole replacement identified as 'risk-driven replacement'.

50 Response to information request IR031

United Energy refers to the output of its own unitised volume forecasting models as 'condition-based' pole replacement and reinforcement.

182. United Energy has not provided Powercor's model, or explained the assumptions applied by United Energy (or Powercor) in applying its model. We review the proposed expenditure as part of our assessment of poles repex.

Substation transformer and switchgear replacement

183. United Energy's approach to managing risk for substation assets is to focus on the overall zone substation risk, rather than each complex (or high value) asset. United Energy describes this as:[51]

> *'Our approach is a whole of system approach, which uses a failure rate derived from our historic asset replacement and failure data. It is not developed using the CBRM health index approach.'*

184. We asked how United Energy determined which projects would not be included in the repex forecast, and the level of consideration of packaging projects at common zone substation sites that has been included. United Energy states that:[52]

> *'All zone substations were assessed using our risk quantification model. An initial 'first pass' of the model using standard unit prices allowed most zone substations to be filtered out. More detailed scoping and pricing for sites that were not filtered was then undertaken to identify efficient timing of works;*
>
> *The attached risk monetisation model, 'UE IR031 - Q12 - UE MOD 4.04_all sites', facilitates analysis on the full list of zone substations in our network; and*
>
> *The packaging of projects was then considered during our iteration process. This involved a manual review by subject matter experts to assess which projects could align, their drivers, and suggested timing. The estimation of individual or combined projects was then taken into account in our forecasts.'*

185. With regard to alignment to the AER industry practice note, United Energy states that that its whole of system approach:[53]

> *'…allows us to intervene on a single poor condition asset and subsequently defer replacement (or other action) on the remaining assets. This inherently manages risk and uncertainty while minimising regret, insomuch as it 'buys time' for the second unit that may not be required in future periods; and*
>
> *We are also yet to see evidence that major plant will become redundant in the near future (or within a period that would allow us to maintain risk at manageable levels without intervention). The risks associated with our underlying assets, however, remain. This recognises that we are the second most utilised network in Australia, meaning that all else equal, we face higher consequences of failure relative to other networks.'*

186. United Energy has provided business cases and risk-monetisation models for its transformer and switchgear assets, which include the proposed economic commissioning year. The proposed economic commissioning year provides a smoothed expenditure profile. Amongst other things, United Energy claims that this will assist with managing deliverability risk.

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[51] United Energy response to information request IR016

[52] United Energy response to information request IR031

[53] United Energy response to information request IR031

Protection and control systems

187. In response to a request for further information to support the proposed expenditure, and in particular the details and rationale for the forecast increase in SCADA repex, United Energy provided a risk model for protection and control related projects. We have reviewed the model as part of our assessment of the proposed expenditure.

Other targeted project and program expenditure

188. A number of additional projects and programs are included in United Energy's forecast repex 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.

189. For these projects, we looked for evidence to confirm United Energy's claim that the expenditure is prudent, efficient and reasonable. Given the quantum of expenditure, we expected documentation consistent with the normal requirements of a business case.

190. 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 United Energy has included in its proposed forecast.

4.3.4 Allocation to RIN categories

191. United Energy includes a number of projects and programs for which the expenditure is allocated across multiple categories. The basis for this allocation, and the percentages applied, have not been explained by United Energy.

192. We show the allocation of project-based expenditure in the table below and the corresponding allocation to each RIN group.

Table 4.5: Allocation of project-based expenditure by RIN group- $m, real 2021

		Allocation to categories				
Project grouping	**Total**	**Transformer**	**Switchgear**	**SCADA[54]**	**Underground cable**	**Other**
Transformer replacement (16 sites)	32.1	20.6	4.5	2.9	1.9	2.2
Switchboard replacement (8 sites)	15.9	0.8	9.5	0.8	4.8	-
Switchyard replacement (3 sites)	3.7	-	2.6	-	-	1.1
SH 6.6kV conversion	3.8	2.4	0.5	0.3	0.2	0.3
STO station risk management	0.3	0.2	0.0	0.0	0.0	0.0
Total	**55.8**	**24.0**	**17.2**	**4.1**	**6.9**	**3.6**

Source: EMCa analysis of IR034 – UE MOD4.03 mapping reconciliation. Excludes real cost escalation

193. United Energy apply a similar allocation method to its 'animal proofing' related program expenditure[55] as shown in the table below, with the corresponding allocation to each RIN group.

[54] SCADA, network control & protection systems

[55] 'animal proofing' refers to the list of programs included in the table

Table 4.6: Allocation of program-based expenditure by RIN group - $m, real 2021

Program name	Total	Allocation to categories: Transformer	Switchgear	Underground cable
Minor animal proofing (Minor) HV/LV	0.5	0.1	0.3	0.1
Possum protection	2.9	0.8	1.8	0.4
Possum protection SW, S/S, CHP	0.0	0.0	0.0	0.0
Bird/Animal proofing on network	3.6	1.0	2.1	0.5
Total	**7.1**	**1.9**	**4.2**	**0.9**

Source: EMCa analysis of IR034 – UE MOD4.03 mapping reconciliation. Excludes real cost escalation

194. For the expenditure related to animal proofing, we typically see this allocated to the 'other' repex group, rather than to a specific RIN group or asset category.

195. In this respect, the proposed allocation of project and program expenditure may have implications to the modelling undertaken using the AER's Repex model (i.e., when comparing historical expenditure and practices) to the extent that United Energy vary from what has been proposed. We note that we have not been requested to review the AER's Repex model, or the implications of these proposed allocations on the results.

196. We have sought to include in our assessment the total expenditure associated with each project and program, where it best aligns with the assets included in each group. For example, we review transformer replacement in the transformer group, noting that 36% of the proposed expenditure for transformer replacement is allocated to other categories.

4.3.5 Justification of expenditure

Justification documentation provided is not sufficient

197. The originally-provided justification documentation from United Energy did not constitute an adequate level of supporting evidence to justify the proposed expenditure. We therefore requested additional information from United Energy to justify the proposed expenditure in each asset group (i.e., business cases or similar, including details of scope, key drivers, asset condition, risk information relied upon in developing the forecast, the options considered, and any 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

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

199. We discussed this additional information request during our onsite meeting with United Energy, at which time we were again directed back to the originally provided information. We asked further questions of United Energy and where new information was provided, we have referred to this in our assessment.

200. With respect to United Energy's repex program, we were able to determine the volume of replacements and associated forecast expenditure by applying the derived unit rates for the next RCP. However, in many 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 United Energy supplied.

Project and program justification documentation

201. The information provided in the business case documentation from United Energy was specific to only a small number of projects and programs. Further, the responses to information requests generally referred back only to specific models and explanations. This left significant areas of the proposed forecast expenditure largely unexplained. We did use the information provided to derive historical replacement volumes and trends and sought to ascertain the basis for inclusion of projects and programs into the forecast from other information provided, such as asset strategy documents.

202. We observed a reliance on the expenditure models - which include lists of projects and programs - and appear to reflect an assumption that the underlying level of replacement volumes would continue and be projected forward based on the averaging approach proposed.

203. As noted above, 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 repex 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

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

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

Absence of sufficient evidentiary support from United Energy

206. There is insufficient evidence to justify the volume and cost assumptions that United Energy has included in its proposed forecast and to justify how these assumptions reflect an optimised risk outcome. We therefore looked for evidence of justification of the proposed expenditure, consistent with the normal requirements of a business case-like document, from the other information that we were provided.

207. 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 United Energy.

4.4 Assessment of United Energy's proposed repex by RIN group

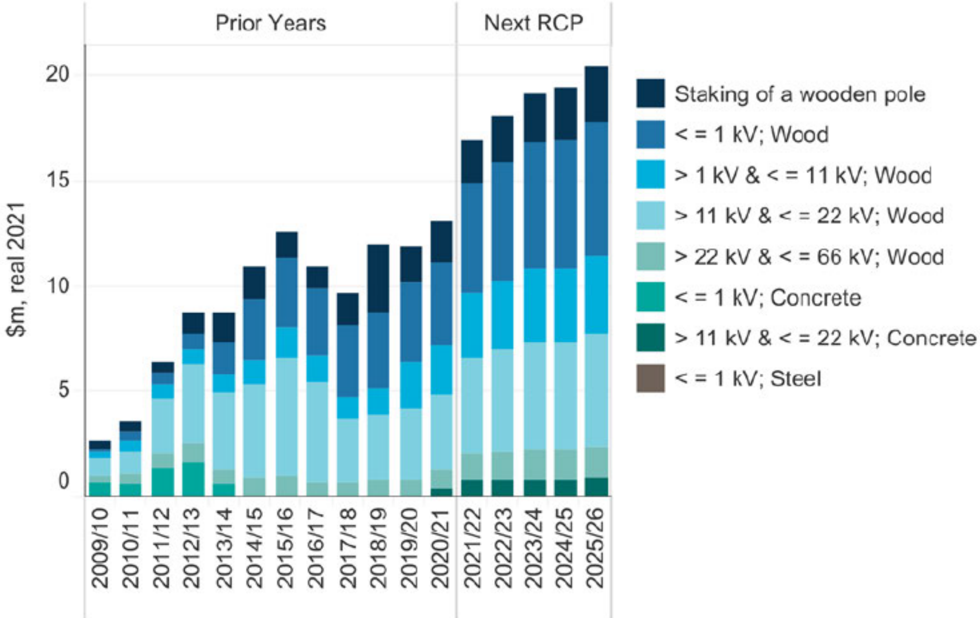
4.4.1 Poles

United Energy's forecast

208. United Energy has proposed $90.2m[56] for the Poles asset group in its repex forecast for the next RCP. The expenditure profile for the Poles asset group showing the next RCP compared with previous years is shown in the figure below.

[56] Project expenditure which excludes real cost escalation

Figure 4.4: Poles repex by asset category - $m, real 2021



Source: United Energy Reset RIN

209. The figure above shows that the largest increase in the next RCP is associated with LV pole replacement. The major components of expenditure (direct costs only) and program by construction type are shown in the tables below. Real cost escalation is excluded.

Table 4.7: Components of United Energy's proposed Poles repex for next RCP - $m, real 2021

Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Programs						
Replacement	11.4	12.1	12.7	13.4	14.1	63.7
High voltage	*6.2*	*6.6*	*6.9*	*7.3*	*7.6*	*34.6*
Low voltage	*4.3*	*4.5*	*4.8*	*5.1*	*5.3*	*24.0*
Sub-transmission	*0.9*	*1.0*	*1.0*	*1.1*	*1.1*	*5.2*
Reinforcement	2.0	2.2	2.3	2.4	2.5	11.3
High voltage	*0.8*	*0.8*	*0.9*	*0.9*	*0.9*	*4.3*
Low voltage	*1.1*	*1.2*	*1.3*	*1.3*	*1.4*	*6.3*
Sub-transmission	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.6*
New service poles to meet regs	0.0	0.0	0.0	0.0	0.0	0.1
Projects						
Incremental pole replacement: risk-based pole replacements	2.5	2.5	2.6	1.8	1.8	11.2
Replacement of concrete poles in non-CMEN area	0.8	0.8	0.8	0.8	0.8	3.9
Total	**16.7**	**17.6**	**18.4**	**18.4**	**19.2**	**90.2**

Source: EMCa analysis of IR034 UE MOD4.03 mapping reconciliation. Excludes real cost escalation

Table 4.8: United Energy's proposed Poles repex for next RCP by construction type - $m, real 2021

Total	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Wood poles	15.9	16.8	17.6	17.6	18.4	86.3
Concrete poles	0.8	0.8	0.8	0.8	0.8	3.9
Total	**16.7**	**17.6**	**18.4**	**18.4**	**19.2**	**90.2**

Source: EMCa analysis of MOD 4.03. Excludes real cost escalation

210. United Energy provided the following documentation with its submission to support its forecast Poles expenditure:

- a business case for its pole replacement program[57]; and
- models comprising its plant, stations and lines replacement expenditure (UE MOD 4.03) and unitised volume model (UE MOD 4.02), which include poles repex.

Our assessment

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

211. 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 4.9: United Energy's proposed pole intervention volume for next RCP

Forecasting component	Replacement	Reinforcement	Total
Condition based	5,609	9,170	14,779
Risk based	941	-	941
Concrete pole replacements in non-CMEN areas	1,390	-	1,390
Total	**7,940**	**9,170**	**17,110**

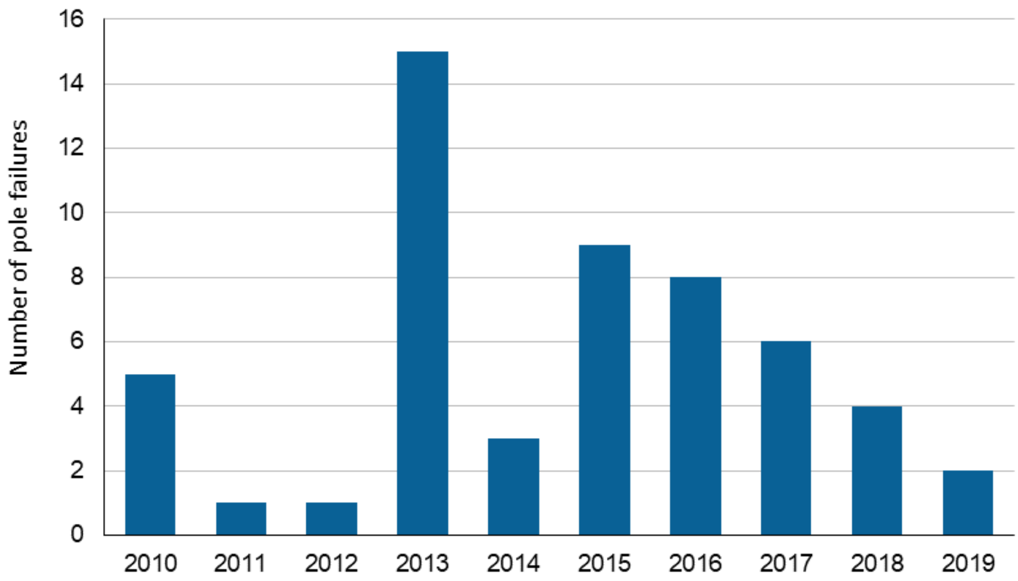
Source: EMCa analysis of MOD 4.03

The basis for an increase in United Energy's pole treatment volumes is not compelling

212. United Energy's network shows a declining wood pole failure trend, as shown in the figure below.

57 United Energy BUS 4.02 Pole replacements: forecast method overview

Figure 4.5: United Energy's historical wood pole failures



Source: EMCa analysis of response to information request IR032 and IR035

213. United Energy has not demonstrated that the underlying pole condition or associated network risk is increasing. As noted in section 3.2.4, United Energy's reliability performance is good and improving, and fire start events are declining. United Energy has not demonstrated that the level of network risk associated with its pole population is escalating. Both of these factors undermine United Energy's justification for increased pole repex.

214. There is limited evidence of United Energy's efforts to moderate the forecast expenditure, cognisant of the improving pole population performance, by using the top-down review methods described in section 2 to align the forecast outcomes with network risk.

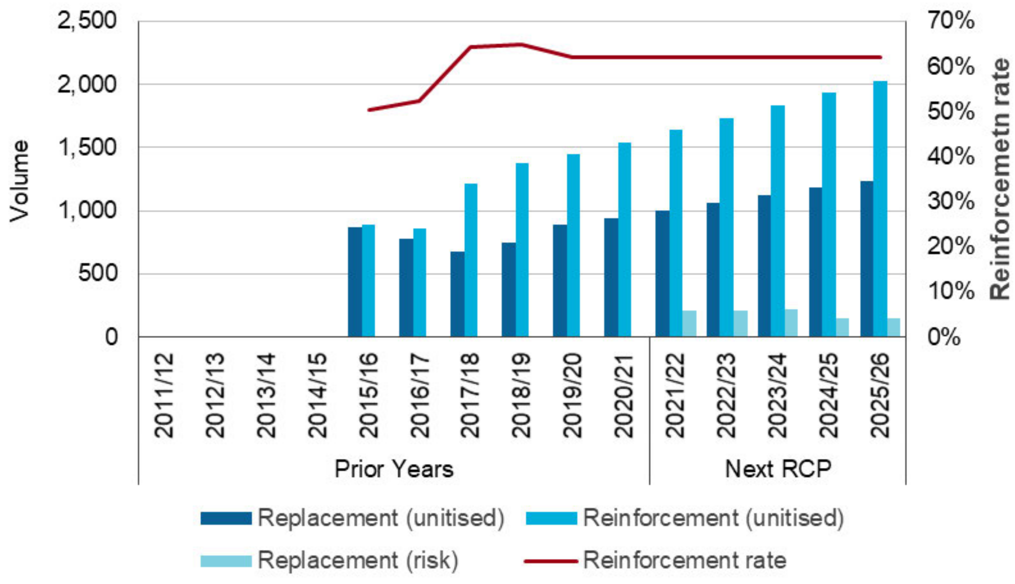
United Energy has applied a hybrid approach to developing the forecast treatment volumes

215. United Energy has forecast its poles repex program in four separate components as follows:

- Condition-based replacements;
- Condition-based reinforcements;
- Risk-based replacement; and
- Concrete pole replacements.

216. The condition-based replacement and reinforcements are forecast based on the volumes from its unitised model. The remaining elements are specific projects included in its lines replacement model and business case. We describe the basis for each of these components in subsequent sections.

Figure 4.6: Pole intervention volumes (wood poles only)[58]



Source: EMCa analysis of UE MOD 4.03

217. As shown in the figure above, both replacement and reinforcement volumes are increasing over time and United Energy forecasts a continuing increase. The reinforcement rate shown above does not include risk-based pole replacements. After taking these additional replacements into account, the implied average wood pole reinforcement rate would reduce from 62% to 58% for the next RCP.

Condition based replacement and reinforcement is based on an expectation of a 'base' level of replacement continuing

218. As noted above, United Energy has forecast its condition-based replacement and reinforcement volume using its unitised model. United Energy describes the use of its unitised model for forecasting poles repex as:[59]

> *'Our forecast for condition-based interventions is derived from observed long-term trends in our historic pole intervention activities since 2010. The framework to which poles are inspected, staked or replaced has not changed for many years. This framework is overseen by ESV (i.e., changes must be approved by ESV), and has delivered low numbers of pole failures for our network that to date, have satisfied both ESV and our customers' expectations; and*
>
> *The derivation of the forecast based on this approach is set out in our unitised volume model (UE MOD 4.02), included as part of our regulatory proposal. Specifically, our pole intervention forecasts are initially determined based on the four letter material codes in rows 95–97. These intervention forecasts are further disaggregated into either replacements or reinforcements (refer to rows 101–106) based on the observed staking ratios in rows 11–16.'*

219. United Energy has selected a linear trend approach for establishing its forecast requirements for each of the pole-related components in its unitised model based on the previous 9 years of historical data. United Energy has not provided the basis for selecting the linear trend approach for each of the components for poles, being:

- New service poles to meet regulations (PDN);
- Pole replacement - high voltage (RPH);

58 Replacement volumes were not provided for years prior to 2015/16 in UE MOD 4.03

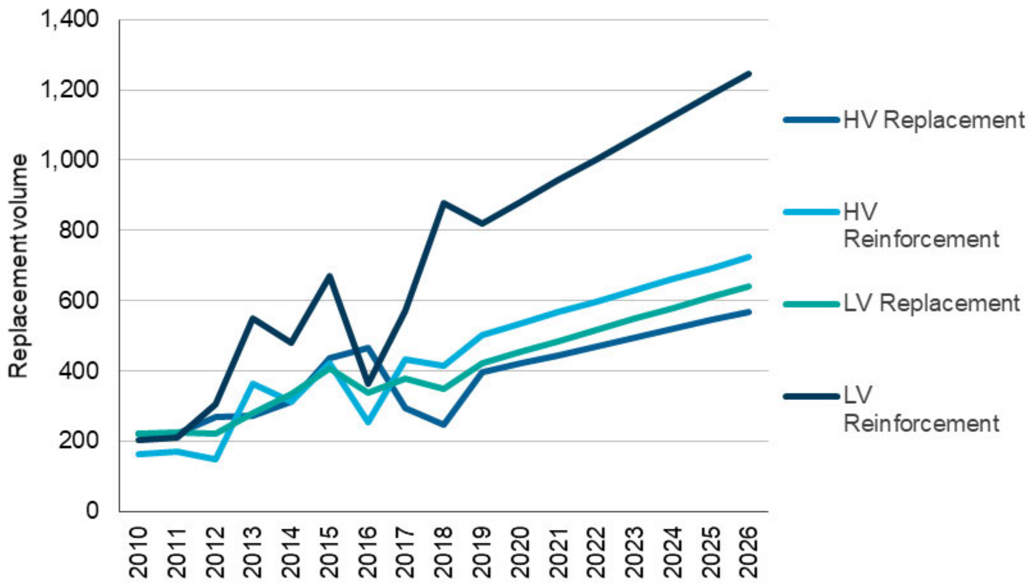
59 Response to information request IR009 poles repex

- Pole replacement - low voltage (RPL);
- Pole replacement – sub-transmission (RPS);
- Pole reinforcement – high voltage (RRH);
- Pole reinforcement – low voltage (RRL); and
- Pole reinforcement – sub-transmission (RRS).

220. There is a further component, Pole reinforcement – PL (RRP), which we understand is associated with Public lighting and categorised as a part of Other repex. We include consideration of this in our assessment of Other repex in section 4.

221. We show the outcome of the trending approach for the high-volume components in the figure below.

Figure 4.7: Condition based forecast requirements of pole-related components



Source: EMCa analysis of MOD4.02

222. As can be seen in the above chart, the forecast for pole replacement and reinforcement is steadily increasing. United Energy has not provided sufficient justification for the proposed profile for any of its pole-related components of expenditure, other than being based on observed long-term trends and asset management practices that do not appear to have changed for many years.

223. Based on our analysis and review of the figure above, the treatment volumes suggest that a change has occurred in more recent history - and specifically treatment volumes in 2010 and 2011 - or as a trend from these historical values that is unlikely to be representative of current asset management approaches. Adoption of a shorter period, such as the most recent 5 years, is likely to be more representative.

224. Applying a calibration period of the most recent 5 years to United Energy's model changes the modelling approach from a linear trend to an averaging approach. This reduces treatment volumes by around 5,000 poles across the high-volume components. The corresponding reduction to poles repex would be approximately $25m for the next RCP.

Basis for addition of a risk-based replacement program is not compelling and potentially duplicates requirements

225. United Energy makes reference to the ESV technical review of Powercor's pole management practices[60] as the basis to modify its own forecasting method. However,

[60] We provide additional context that in relation to the ESV technical review in Appendix A

United Energy does not appear to have implemented a forecast based on a similar serviceability index or pole calculator to that of Powercor or CitiPower. Nor does United Energy appear to recognise that the performance of its pole population is different, or that the declining treatment volumes evident in Powercor's pole population are not present in United Energy's pole population.

226. Rather, United Energy has added a forecast of risk-based pole replacements to its existing and underlying 'condition-based' forecasting method, based on historical treatment levels. A risk-based forecast typically targets the highest risk poles to treat and seeks to identify a level of pole treatment across the entire pole population, rather than a subset, to maintain the level of risk.

227. We understand that in developing the forecast of at-risk pole replacement, United Energy applied Powercor's enhanced pole calculator (by providing data to Powercor) for its lower durability pole population (S3). It then incorporated the outputs of the enhanced pole calculator into its forecast for treatment volumes.

228. United Energy provided the total volume of risk-based pole replacements in its business case. In its response to our information request,[61] it further splits this total replacement volume between Class 3 poles in HBRA and other poles. United Energy has not provided evidence of the network risk reduction achieved through this volume of pole replacements, or why this is required in addition to the 'base' level of pole treatments identified under its historical trend condition-based forecasting method.

229. United Energy has not demonstrated why the assumptions adopted by Powercor should be applicable to its own pole population, and how they relate to the level of risk present in the United Energy network.

No evidence of risk assessment for wood poles forecast requirements

230. In its business case, United Energy states:[62]

> *'The application of our enhanced serviceability index assessment method uses our underlying pole condition data for class three poles only; and*
>
> *The serviceability outputs for our class three population are used as a proxy for the probability of pole failure, with high bushfire risk areas targeted to reflect the greater consequence of failure (relative to low bushfire risk areas).'*

231. Whilst the risk-based pole replacement is described as being based on a risk assessment utilising an existing pole condition and serviceability method, United Energy does not present a risk assessment for any part of its wood pole program. United Energy states that:[63]

> *'In regards to full risk modelling of individual poles, we do not currently have systems that allow us to undertake this analysis. That said, as our condition-based program reflects our existing asset management practices that are approved by ESV, it reflects a 'do-nothing different' approach. Our forecasts for this program are expected to maintain our existing performance, recognising that our pole population will continue to deteriorate over time.'*

232. United Energy also states:[64]

> *'Whilst data limitations currently prevent us from quantifying the asset risk cost in accordance with the AER's risk monetisation approach, we regard it as prudent and efficient to undertake additional risk-based replacement volumes, consistent with our*

61 Response to information request IR016 - risk based wood pole replacement model

62 United Energy BUS 4.02 Pole replacement page 16

63 Response to information request IR009 poles repex

64 United Energy BUS 4.02 Pole replacement page 16

safety obligation to ensure that safety risk is as low as reasonably practicable. We also consider our conceptual approach is consistent with the AER's risk framework.'

233. United Energy has not provided an overarching framework from which economic analysis can be undertaken to determine an efficient level of expenditure, consistent with its claim of being consistent with the AER risk framework, or an economic test to justify inclusion of its additional risk-based replacement volumes to ensure that safety risk is As Low As Reasonably Practicable (ALARP).

234. As a bottom-up consolidation of requirements was developed by United Energy using different forecasting methods, we consider that there is potential for duplication of required treatment volumes to address the same risks. We have not seen evidence from United Energy to demonstrate that this potential for duplication has been taken into consideration.

Replacement of non-CMEN connected concrete poles appears sound

235. United Energy has provided an economic model[65] that determines the risk-cost presented by its population of concrete poles that are not connected to the Common Multiple Earthed Neutral (CMEN) system, otherwise referred to as non-CMEN poles. United Energy has undertaken an NPV analysis based on the repex required to address the risk, offset by the avoidance of risk-cost associated with injury or fatality.

236. United Energy proposes to replace 2,780 legacy concrete poles that are not connected to the CMEN system over a 10-year remediation period. The input assumptions used in the risk model appear reasonable. Consideration of a staged and prioritised program over a 10-year period is sound.

Unit cost estimates may not reflect the full benefit of delivered cost efficiencies

237. Unit rates are calculated for each asset category based upon revealed actual costs, using the sum of the historical expenditure (converted to $2021) divided by the sum of the historical volumes for the period 2015/16 to 2018/19 (e.g., 4 years). This seeks to remove year on year variations.

238. The selection of an averaging period based on results from the most recent 3 years results in a lower unit cost than United Energy has applied, as shown in the table below.

Table 4.10: Impact of changing averaging period for unit costs - $2021

Unit rate	5 years	4 years	3 years	1 year
	Not avail	15/16-18/19	16/17-18/19	18/19
Reinforcement				
LV		1,155	1,106	1,028
HV		1,321	1,296	1,256
ST		1,376	1,354	1,290
Replacement				
LV		8,509	8,342	7,548
HV		13,633	13,221	11,161
ST[66]		20,440	20,990	21,506

Source: EMCa analysis of MOD4.03

239. The unit costs determined from the most recent year are consistent with what we would expect to see. Further, using revealed costs is a reasonable indicator of the efficient cost (assuming that any changes to the procurement practices and standards are a reasonable reflection of the future cost). We asked United Energy to provide us with its cost estimation

65 Response to information request IR009 – Q11 – non-CMEN concrete poles risk and expenditure model

66 Referred to by United Energy in this model as SUBT

methodology (or similar) to understand the basis for determining unit rates. In response, United Energy outlined its use of an average of historical unit rates as described in section 3.2.4 and that it considered its approach to reflect efficient costs:[67]

’As set out in our regulatory proposal, we operate an outsourced structure for constructing and maintaining our distribution network. This means all capital works are undertaken by independent, third-party service providers following open, competitive tenders. This approach ensures our historical unit rates are efficient.’

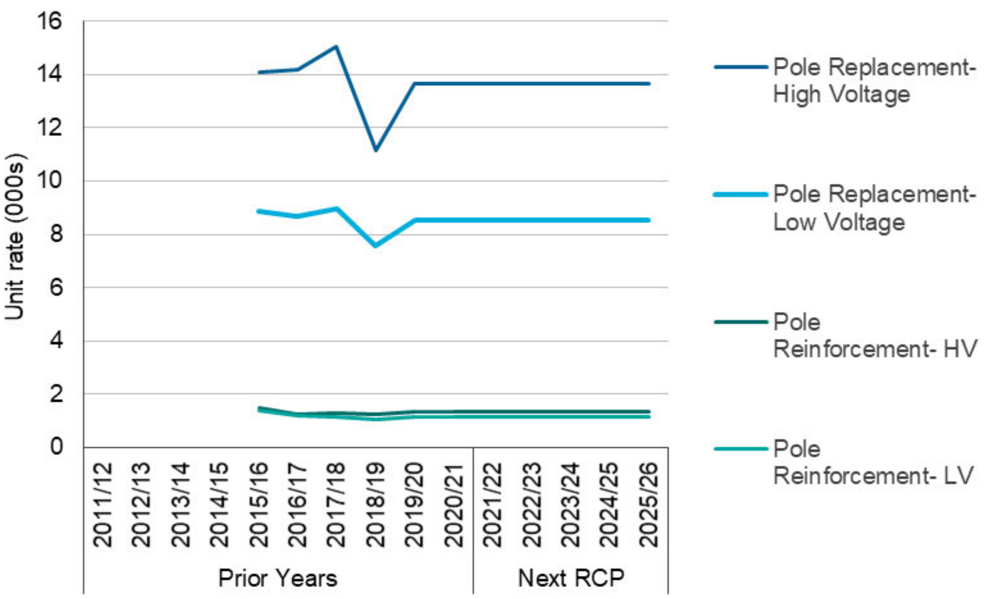
240. As discussed earlier in this report, United Energy has achieved similar levels of savings to Powercor and CitiPower. These savings are expected to deliver reductions to the unit costs. United Energy described these savings as:[68]

‘Achieved savings in field services, asset inspection, vegetation management and major projects through renegotiating service provider contracts through market testing and using a contestable panel of service providers; and

Realised synergies with CitiPower and Powercor by rationalising support functions, using combined tendering of outsourced services (leveraging economies of scale), reducing reliance on outsourced service providers and adoption of efficient processes and practices through leveraging learnings with CitiPower and Powercor.’

241. We plotted the derived[69] unit rates in the same way that United Energy calculated the proposed unit rates to understand how they varied year on year, and to determine if the savings realised by the improvement programs were reflected in the unit rates. The results are shown in the chart below.

Figure 4.8: Derived unit rates (excluding real cost escalation) - $’000, real 2021



Source: EMCa analysis of MOD4.03

242. It is not evident to us that the cost efficiencies delivered earlier in the current RCP, and that appear to be present in 2018/19, have been reflected in the unit costs used in the development of the forecast expenditure. In the absence of this information, we consider the unit costs and forecast expenditure are both likely to be higher than an efficient level.

67 Response to information request IR016

68 United Energy presentation to AER/EMCa onsite review meeting

69 Unit rates were derived by dividing the expenditure incurred in each financial year by the replacement volumes in that same year. This varies from an averaging method

Summary of our assessment

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

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

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

- United Energy has not established a reasonable basis for the extent of its proposed increase in expenditure;
- The expenditure forecast is based on a bottom-up assessment, combining three different forecasting methods, which is likely to duplicate the requirements for pole interventions;
- The basis for selection of a linear trend included in its unitised model using 9 years of historical data is not explained, and leads to a higher level of intervention volume than it is likely to require;
- The basis for separately forecasting replacement and reinforcement interventions based on current trends does not consider the most efficient economic investment decision for intervention;
- United Energy has not presented a risk assessment for the proposed wood pole program, including evidence of an economic test to support inclusion of a risk-driven replacement component that purports to meet ALARP; and
- Unit cost estimates relied upon in development of the forecast may not reflect the full benefit of delivered cost efficiencies.

246. The incremented program for concrete pole replacement ($3.9m) appears reasonable.

247. Overall, we consider that United Energy has not justified the extent of the proposed increase to its forecast expenditure for the Poles group.

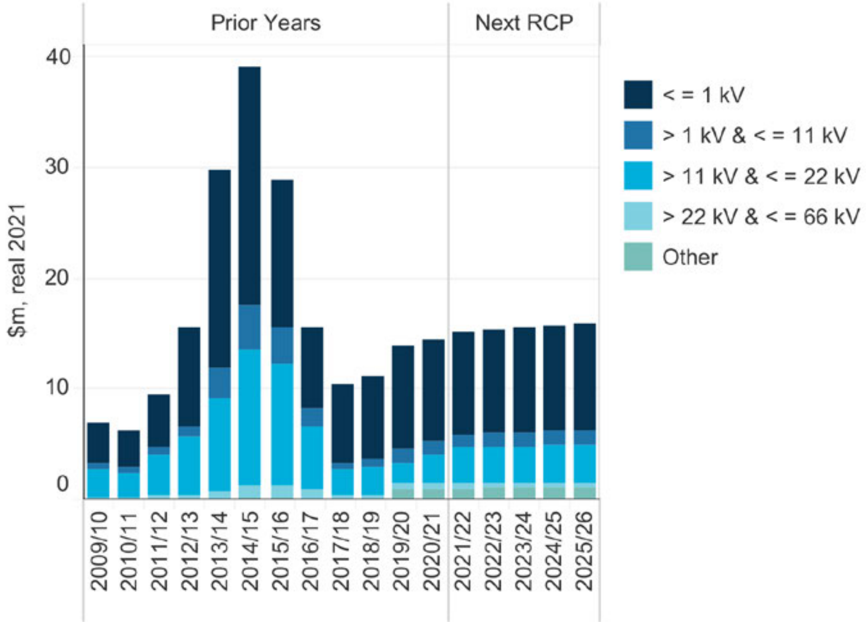
4.4.2 Pole top structures

United Energy's forecast

248. United Energy has proposed $74.6m[70] 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 prior years is shown in the figure below.

70 Project based expenditure excluding real cost escalation

Figure 4.9: Pole top structure repex by asset category - $m, real 2021



Source: United Energy Reset RIN

249. The figure above shows a similar level of forecast expenditure when compared with recent years and which is lower than the historical average. The major components of expenditure are shown in the table below (and which reconcile to United Energy's program when real cost escalation is excluded).

Table 4.11: Components of United Energy's proposed Pole-top structure repex for next RCP - $m, real 2021

Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Programs						
LV crossarms replacement	5.1	5.1	5.1	5.1	5.1	25.4
LV strain, termination, anchor replacement	4.1	4.1	4.1	4.1	4.1	20.4
HV crossarms replacement	2.2	2.2	2.2	2.2	2.2	11.1
HV crossarm replacement strain, anchor, termination	0.9	0.9	0.9	0.9	0.9	4.5
Stay wire replacement	0.5	0.5	0.5	0.5	0.5	2.5
HV insulator replacement (set of 3)	0.5	0.5	0.5	0.5	0.5	2.3
ST crossarms replacement	0.2	0.2	0.2	0.2	0.2	1.0
Sub Transmission crossarm replacement, strain, anchor, termination	0.2	0.2	0.2	0.2	0.2	0.9
Replacement ex thermal survey	0.1	0.1	0.1	0.1	0.1	0.6
Sub Transmission insulator replacement (set of 3)	0.0	0.0	0.0	0.0	0.0	0.2
LV insulator replacement	0.0	0.0	0.0	0.0	0.0	0.1
Projects						
Replacement of HV Wood crossarm in HBRA	1.4	1.3	1.3	1.3	1.3	6.6
Incremental pole replacement: pole-top structure offset	-0.2	-0.2	-0.3	-0.2	-0.2	-1.1
Total	**14.9**	**14.9**	**14.9**	**15.0**	**14.9**	**74.6**

Source: EMCa analysis of IR034 UE MOD4.03 mapping reconciliation. Excludes real cost escalation

250. United Energy provided the following documentation with its submission to support its proposed expenditure:

- Unitised volume model (UE MOD4.02) - which forecasts replacement volumes based on historical replacement volumes for low-cost, high-volume asset interventions of which pole-top structures is a component; and
- Expenditure model - comprising its Plant, stations and lines replacement expenditure (UE MOD 4.03).

251. United Energy has not provided a business case or other documentation to justify its proposed replacement volumes or expenditure. We therefore sought to understand the rationale for the forecast from our assessment of other supporting information.[71]

Our assessment

Increased expenditure from current levels is based on adjustments to CBRM

252. According to United Energy,[72] the expenditure associated with pole-top structures is increasing from $65.5m in the current RCP to $74.6m in the next RCP. United Energy describe[73] the main driver of replacement is the asset condition based on inspection regime and/or consequences of asset failure. United Energy has not provided information as to the drivers of these components of its proposed expenditure.

71 Including the Regulatory proposal, RIN016 and asset strategy documents

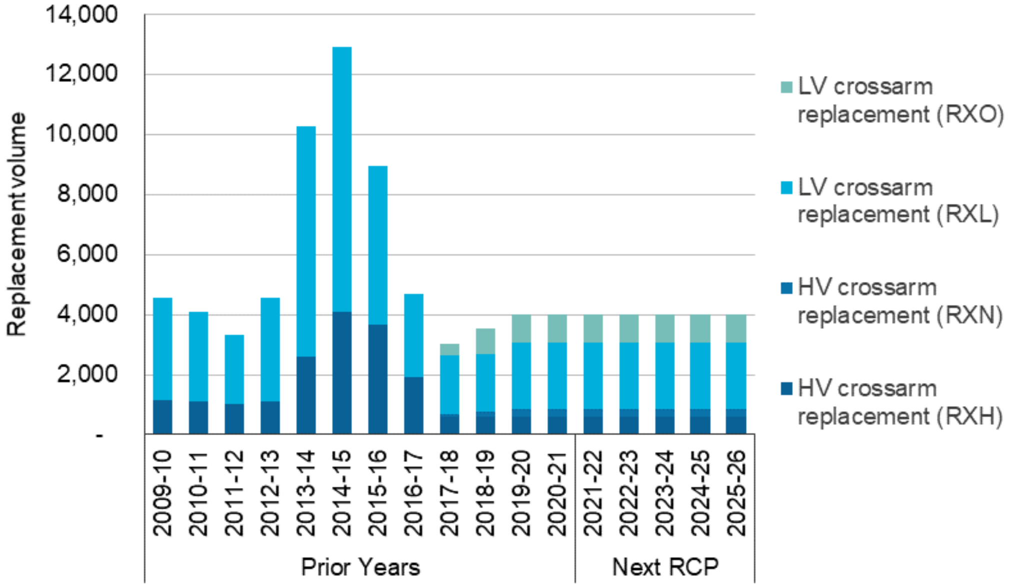
72 United Energy Regulatory Proposal Table 4.8. Total for next RCP is inclusive of the reduction due to incremental pole replacements.

73 United Energy RIN response RIN016

253. We have not been provided with a description of the strategies undertaken by United Energy which led to higher replacement expenditure in the period prior to 2017/018, and the influence that historical expenditure might have on the prudent level of replacement in the next RCP.

254. Based on our review of United Energy's unitised volume model, we observe that the increase in expenditure in Figure 4.9 appears to be driven by increases to LV and HV crossarm replacement and is reflected in the historical volumes included in United Energy's models as shown in Figure 4.10 below.

Figure 4.10: Major components of pole-top structure replacement included in unitised volume model



Source: EMCa analysis of unitized volume model UE MOD4.02. Includes major components of cross arm replacement only

255. The basis for an increase over the next RCP compared with the current RCP is explained by United Energy as being the result of application of a multiplier to its two-year average replacement volume in 2017 and 2018 to account for lower than sustainable replacement volumes due to implementation of its CBRM.

Forecast expenditure is based on unitised volume model

256. United Energy has determined $69.1m (or 93%) of the forecast expenditure based on application of its unitised volume model as described in section 4.3.

257. The forecast method has been adjusted to account for changes to the asset management approach, limiting the calibration period to the last two years using an averaging method.

258. Our review of the unitised volume model has identified potential discrepancy with the historical volumes used for the calibration period. As discussed in section 4.3, the replacement volumes relied upon in the unitised volume model are higher than those calculated by us when applying United Energy's own method to the input data. When adjusting for this difference, and including the averaging method applied by United Energy, the resulting replacement volumes are substantially lower than United Energy has proposed.

259. We have not been provided additional supporting documentation for this forecast expenditure to address the concerns that we raised regarding the application of input data specifically, or the unitised volume method more generally.

Basis for additional projects not adequately supported

260. United Energy has included an additional project for the replacement of HV Wood crossarm in HBRA. This is included as a specific project that we understand is likely to form part of the:[74]

> *'Targeted proactive intervention programs are also included in our bottom-up replacement forecasts for additional safety-driven measures that are consistent with our AFAP obligations.'*

261. We looked for, but did not find, evidence to support the justification for inclusion of this program to meet United Energy's ALARP/AFAP obligations. We expected to see a cost-benefit analysis or application of a safety test to justify the proposed level of expenditure.

262. We understand from the Bushfire mitigation plan[75] provided by United Energy, that a CBRM and risk model has been developed for management of cross-arms. United Energy has made an adjustment to the forecast cross-arm replacement model based on its assessment of the CBRM model for its unitised volume forecast. We were not provided with a copy to review. However, we did not find reference to these models in the development of the forecast for the additional program proposed. Further, we did not find specific reference to the rationale for this program in the Bushfire mitigation plan.

263. As part of its unitised model, United Energy includes $15.6m[76] for HV cross-arm replacement. United Energy has not demonstrated that the proposed program reflects a prudent replacement volume, or that re-prioritisation of its existing program by bushfire risk consequence will be insufficient, such that a new program is required.

264. In response to our request to provide the risk analysis for this program, United Energy provided its risk model.[77] The model includes analysis of four options, including do-nothing (maintain status quo).

265. From the model, it indicates that this program targets replacement of 1,825 HV cross-arms only. However, there is insufficient information to ascertain the risk reduction that relates to this specific subset of HV crossarms for replacement relative to the general population of HV crossarms.

Basis for reduction in replacement to account for increase in proposed pole replacement program is not provided

266. United Energy has included a reduction to its pole-top structure forecast expenditure by including a negative adjustment amount of $1.1m that:[78]

> *'...ensures that cross-arms and other assets that are replaced as part of our incremental pole replacement program are not double-counted (i.e., when replacing a pole, it is typically efficient to also replace the existing pole-top assets).'*

267. Based on our review of the provided models, the adjustment is included as a negative expenditure line that commences in 2021/22 as a proportion of the incremental risk-based pole replacement volume only. Based on its proposed increase in pole replacement, the number of crossarms to be replaced and expenditure adjustment, if included, would reflect a proportional increase.

Summary of our assessment

268. We consider that United Energy has not justified an increase to its forecast expenditure for pole-top structures above that which it is currently incurring. Subject to review of input data

[74] United Energy Regulatory Proposal, page 64

[75] United Energy ATT094 Fire Prevention Plan – 31 January 2020

[76] Comprising the program descriptions of 'HV XARMS replacement' and 'HV Crossarm replacement strain, anchor termination'

[77] Response to information request IR052 – Q1 – proactive HV crossarms in HBRA

[78] United Energy Regulatory Proposal, page 63

assumptions for its unitised volume model, forecast expenditure is likely to be at a level slightly lower than is currently proposed.

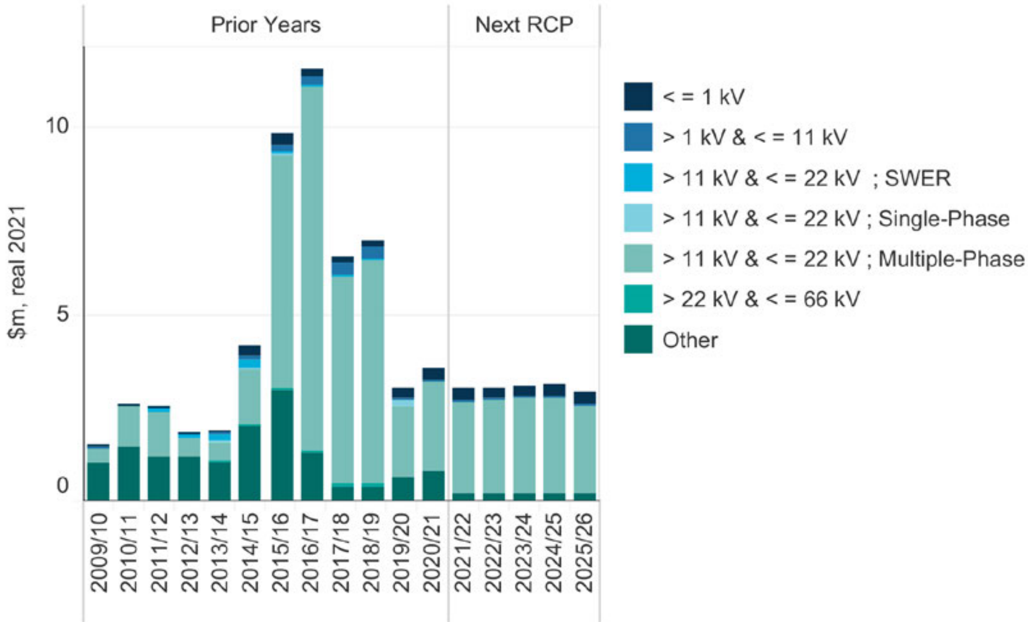
269. United Energy has not justified the drivers and basis for inclusion of a further targeted program for the replacement of HV crossarms and has not sufficiently explained the relationship to its existing HV crossarm replacement project so as to avoid duplication between programs. If the project is being proposed by United Energy to support meeting its AFAP obligations, we would have expected to see a cost-benefit analysis (or similar) to confirm that the proposed expenditure is required to meet its AFAP obligations.

4.4.3 Overhead conductors

United Energy's forecast

270. United Energy has proposed $14.6m[79] 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 4.11: Overhead conductor repex by asset category - $m, real 2021



Source: United Energy Reset RIN

271. The figure above shows a similar level of forecast expenditure when compared with recent history, and which is lower than the historical average. The major components of expenditure are shown in the table below (and which reconcile to United Energy's program when real cost escalation is excluded).

[79] Project based expenditure excluding real cost escalation

Table 4.12: Components of United Energy's proposed Overhead conductor repex for next RCP - $m, real 2021

Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Programs						
Open wire replacement	0.4	0.4	0.4	0.4	0.4	1.8
O/H line replacement - LV ABC	0.2	0.2	0.2	0.2	0.2	0.8
LV Open Wire Replacement (route metre)	0.1	0.1	0.1	0.1	0.1	0.6
HV ABC replacement	0.0	0.0	0.0	0.0	0.0	0.2
Install / replace HV fault indicators	0.0	0.0	0.0	0.0	0.0	0.2
Overhead Conductors	0.0	0.0	0.0	0.0	0.0	0.0
Projects						
Bare conductor replacement in HBRA	1.6	1.6	1.6	1.6	1.6	7.8
Bare conductor replacement program in LBRA	0.5	0.5	0.5	0.5	0.3	2.3
Replacement of OH fault indicator	0.1	0.1	0.1	0.1	0.1	0.6
HV spreader replacement	0.0	0.0	0.0	0.0	0.0	0.2
LV spreader replacement	0.0	0.0	0.0	0.0	0.0	0.2
Total	**3.0**	**3.0**	**3.0**	**3.0**	**2.7**	**14.6**

Source: EMCa analysis of IR034 UE MOD 4.03 mapping reconciliation. Excludes real cost escalation.

272. United Energy has provided the following documentation with its submission to support its expenditure:

- Unitised volume model (UE MOD 4.02) - which forecasts replacement volumes based on historical replacement volumes for low cost, high volume asset interventions of which overhead conductor is a component; and
- Expenditure model - comprising its Plant, stations and lines replacement expenditure (UE MOD 4.03).

273. United Energy has not provided a business case or other justification document for the proposed replacement volumes or expenditure. We therefore sought to understand the rationale for the forecast from our assessment of other supporting information.[80]

Our assessment

Proposed replacement volume from unitised volume model is decreasing

274. According to United Energy,[81] the expenditure associated with the overhead conductor group is decreasing from $31.9m in the current RCP to $14.6m in the next RCP. United Energy explain[82] that the main driver of replacement is the asset condition based on inspection regime and/or consequences of asset failure. However, United Energy has not provided specific information as to the drivers of the components of its proposed expenditure.

275. Of the total forecast for this group, $3.6m (or 25%) is based on the unitised volume model as explained in section 4.3. The balance is a collection of targeted projects.

276. We have not been provided with a description of the strategies undertaken that led to higher historical replacement expenditure, as evident in the period prior to 2017/018, and the influence that has on the prudent level of replacement in the next RCP.

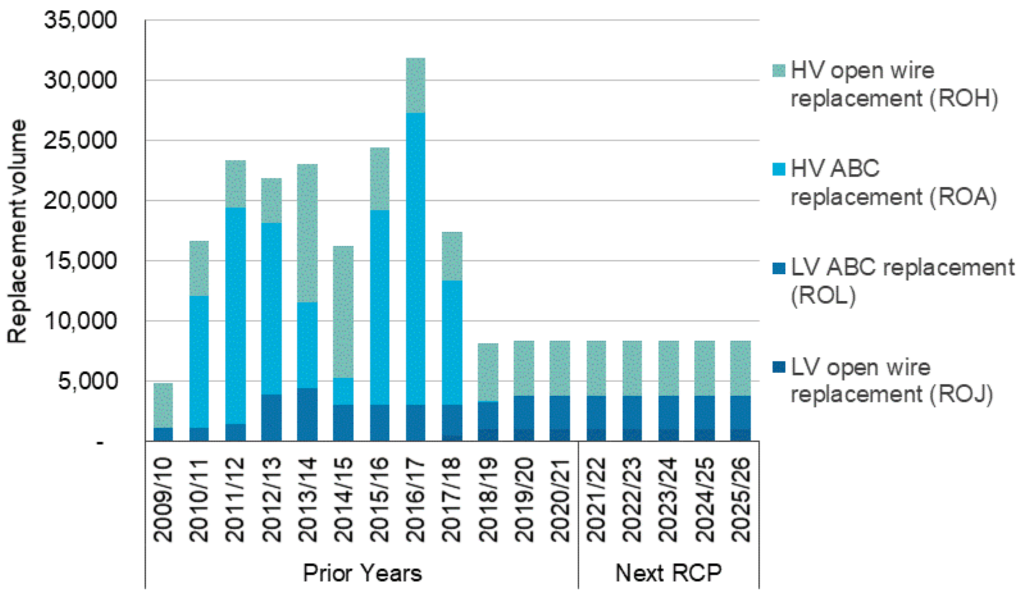
80 Including the Regulatory proposal, RIN016 and asset strategy documents

81 United Energy Regulatory Proposal Table 4.8

82 United Energy RIN response RIN016

277. Based on our review of the unitised volume model, we observe that the increase in expenditure in Figure 4.11 appears to be primarily driven by inclusion of a HV ABC replacement program, and which was completed in 2017-18, as shown in the figure below.

Figure 4.12: Major components of overhead conductor replacement included in unitised volume model



Source: EMCa analysis of unitized volume model MOD 4.02. Includes major components of cross arm replacement only

278. In its response to our request to explain the rationale for the large forecast decrease for overhead conductors, United Energy confirmed our observation:[83]

> *'Our historic expenditure included the replacement of all high-voltage (HV) aerial bundled cable (ABC) in high bushfire risk areas. This program has now been completed; and*
>
> *Our overhead conductor forecast has been developed using our unitised model (UE MOD 4.02), and reflects an averaging period after our HV ABC replacement program concluded so as to not inflate our forecasts.'*

279. For the remaining major component of conductor replacement, the forecast volume of replacements appears similar to trend, and removes the HV ABC replacement as indicated by United Energy.

Basis for inclusion of additional projects is not adequately supported

280. As shown in Table 4.12 above, for the next RCP, United Energy has included projects totalling $11.1m in addition to the unitised model programs. Similar to our assessment of the pole-top structure group, we understand that this is likely to form part of its '*targeted proactive intervention programs.*'[84] We were not provided with the proposed volumes of replacement.

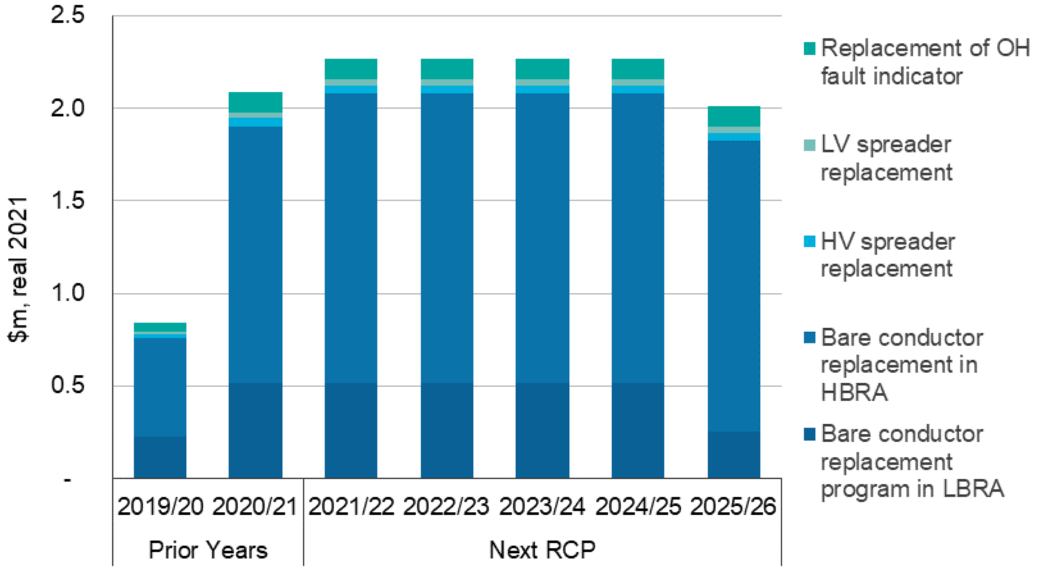
281. We looked for, but did not find, sufficient evidence to support the justification for inclusion of this program to meet United Energy's AFAP obligations. We expected to see a cost-benefit analysis or application of a safety test to justify the proposed level of expenditure.

282. In the figure below, we present the forecast expenditure included in United Energy's models (which relates to the period immediately prior to and including the next RCP).

83 Response to information request IR013

84 United Energy Regulatory Proposal, page 64

Figure 4.13: Proposed Overhead conductor related project expenditure - $m, real 2021



Source: EMCa analysis of IR034 UE MOD4.03 mapping reconciliation

283. We note that these programs are proposed to be commenced in 2019-20. From the project names, we infer that the projects are related to meeting fire prevention or mitigation strategies. We looked for, but did not find, specific reference to the rationale for these projects in the Bushfire mitigation plan,[85] or in any other documents provided by United Energy.

Summary of our assessment

284. We did not find sufficient evidence as required under the NER, and as described by the AER's capital expenditure assessment guideline, to support inclusion of the proposed expenditure. However, we observed that the proposed expenditure for this group is not dissimilar from the long-term trend and that United Energy has correctly accounted for removal of a targeted program that is not continuing into the next RCP.

285. For the Overhead conductor group, on the basis that United Energy has determined that the proposed replacement volume is necessary to meet its safety obligations, we consider the forecast replacement volumes are likely to be reasonable.

286. On balance, due to the low level of expenditure, the forecast is likely to be reasonable.

4.4.4 Underground cable

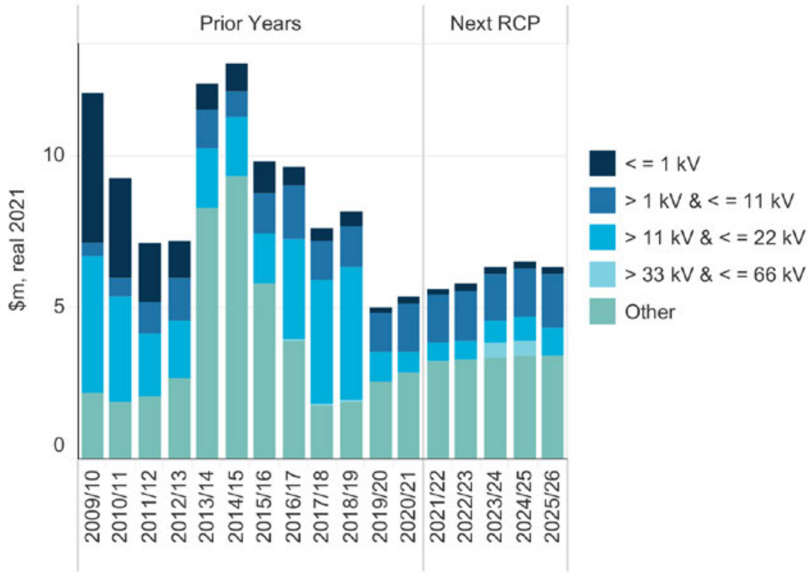
United Energy's forecast

287. United Energy has proposed $29.3m[86] for the Underground cable group in its repex forecast for the next RCP. The expenditure profile for Underground cable comparing the next RCP with previous years is shown in the figure below.

85 United Energy ATT094 Fire Prevention Plan – 31 January 2020

86 Project based expenditure excluding real cost escalation

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



Source: United Energy Reset RIN

288. 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 United Energy's program when real cost escalation is excluded).

Table 4.13: Components of United Energy's proposed underground cable repex for next RCP - $m, real 2021

Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Programs						
Surge diverter replacement (set of 3)	1.8	1.8	1.8	1.8	1.8	8.8
Dist. U/G cable replacement	0.9	0.9	0.9	0.9	0.9	4.3
Underground cable replacement	0.2	0.2	0.2	0.2	0.2	1.1
Pillar to UEL std pillar replacement	0.2	0.2	0.2	0.2	0.2	1.1
Pillar to pit customer service alt	0.2	0.2	0.2	0.2	0.2	0.9
Pillar to pit	0.1	0.1	0.1	0.1	0.1	0.7
CB - service pit replacement	0.1	0.1	0.1	0.1	0.1	0.3
Surge diverter replacement 66kV (set)	0.0	0.0	0.0	0.0	0.0	0.1
Allocated programs						
Animal proofing	0.2	0.2	0.2	0.2	0.2	0.9
Projects						
Replacement of surge arrestors in HBRA	0.6	0.6	0.6	0.6	0.6	3.1
STO 66kV oil cable replacement	0.0	0.0	0.5	0.5	0.0	1.0
Allocated projects						
Transformer Replacement (16 sites)	0.3	0.3	0.4	0.4	0.4	1.9
Switchboard Replacement (8 sites)	0.9	0.9	0.8	0.9	1.2	4.8
SH 6.6kV conversion	0.0	0.1	0.1	0.0	0.0	0.2
STO station risk management	0.0	0.0	0.0	0.0	0.0	0.0
Total	**5.5**	**5.6**	**6.1**	**6.2**	**5.9**	**29.3**

Source: EMCa analysis of IR034 UE MOD 4.03 mapping reconciliation. Excludes real cost escalation.

289. United Energy has provided the following documentation with its submission to support its expenditure:

- Unitised volume model (UE MOD 4.02) - which forecasts replacement volumes based on historical replacement volumes for low cost, high volume asset interventions of which underground cable is a component; and
- Expenditure model - comprising its Plant, stations and lines replacement expenditure (UE MOD4.03)

290. United Energy has not provided a business case or other documentation to justify its proposed replacement volumes or expenditure. We therefore sought to understand the rationale for the forecast from our assessment of other supporting information.[87]

Our assessment

Proposed replacement volume from unitised volume model is relatively flat

291. According to United Energy,[88] the expenditure associated with underground cables is decreasing from $35.9m in the current RCP to $29.3m in the next RCP. United Energy explain[89] that the main driver of replacement is the asset condition and risk profile based on

87 Including the Regulatory proposal, RIN016 and asset strategy documents

88 United Energy Regulatory Proposal Table 4.8

89 United Energy RIN response RIN016

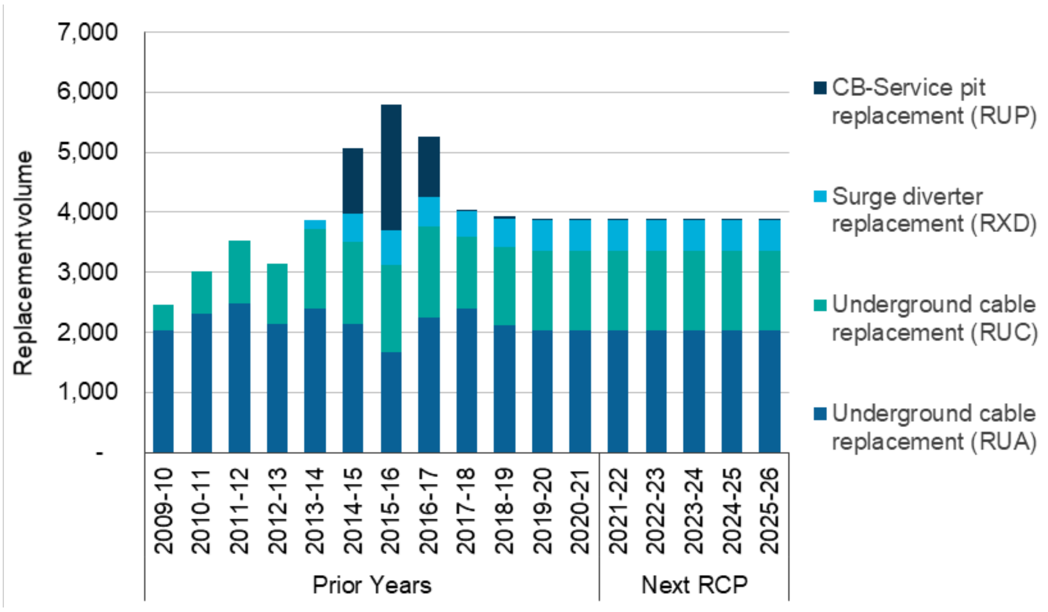
operational experience, fault history, value of lost load, emergency cost, and/or asset failure. However, United Energy has not provided information as to the specific drivers of the components of its proposed expenditure.

292. Of the total proposed expenditure, $17.3m (or 59%) is based on the unitised volume model as explained in section 4.3. The profile of this expenditure for the next RCP is flat, as shown in Figure 4.15 below.

293. We have not been provided with a description of the strategies undertaken which have led to the higher level of historical replacement expenditure and the influence that has on a prudent level of replacement in the next RCP.

294. Based on our review of the unitised volume model, we observe that the increase in prior years was most likely associated with the inclusion of specific replacement projects into the forecast, rather than a change to the underlying asset management approach. The proposed volume of replacements appears similar to the historical trend.

Figure 4.15: Major components of underground cable replacement included in unitised volume model



Source: EMCa analysis of unitised volume model MOD 4.02.

Basis for additional projects is not adequately supported

295. United Energy has included two projects, in addition to the replacements included in its unitised volume model, that total $4.1m for the next RCP:

- Replacement of surge arrestors in HBRA; and
- STO 66kV oil cable replacement.

296. We did not find a description of the need, timing, or analysis for the project to replace surge arrestors in HBRAs. From the project description alone, this would appear to be an ongoing activity and, in the absence of better information, more likely to be captured in the historical replacement volume trend included in its unitised volume model analysis.

297. During the onsite discussions, United Energy stated that the timing of the STO 66kv oil cable replacement project had already been brought forward, and that the project will be undertaken earlier than is proposed in the Regulatory Proposal.

A proportion of the proposed expenditure is related to other projects and programs

298. United Energy has included $7.8m (or 27%) of total underground cable group expenditure as a result of the allocation of expenditure from other categories, as described in section 4.3, and which have been included in the assessment of expenditure categories that best align with the activities being proposed.

299. United Energy has also included $0.9m for animal proofing within the underground cable group, which represents an allocation of 13% of the total $7.1m forecast for animal proofing across other expenditure categories as described in section 4.3.

Summary of our assessment

300. We did not find sufficient evidence as required under the NER, and as described by the AER's capital expenditure assessment guideline, to support inclusion of the proposed expenditure. However, we observe that the proposed expenditure for this group is not dissimilar to the long-term trend, and that United Energy has correctly accounted for removal of a targeted program that is not continuing into the next RCP.

301. On the basis that United Energy has determined that the proposed replacement volume is necessary to meet its safety obligations, we consider that the forecast replacement volume for the Underground cable group is likely to be reasonable.

302. We note that a large portion of the forecast expenditure included for the Underground cable group is due to project allocations across multiple categories. We include our assessment of these projects in other parts of this report.

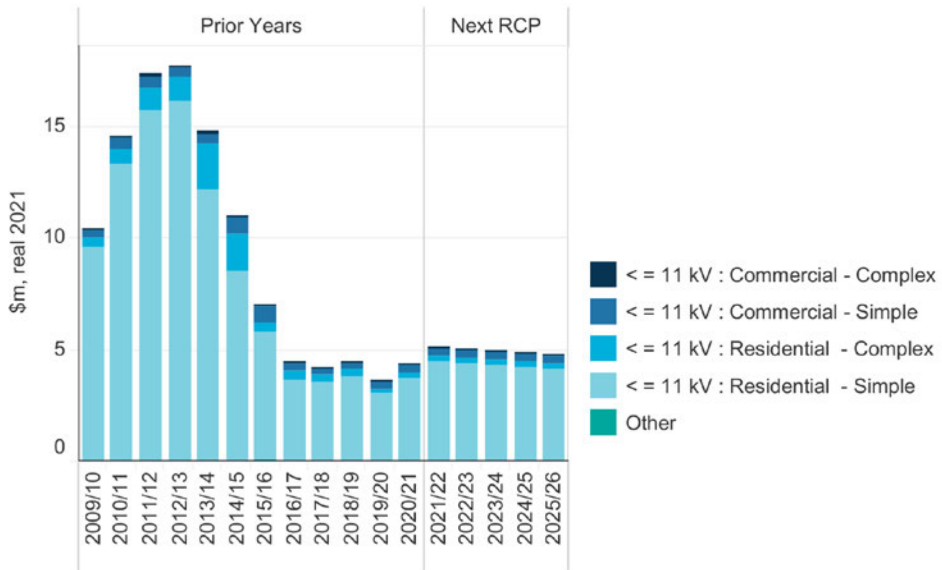
303. Excluding the allocated expenditure, and due to the low level of expenditure, we consider that the forecast for Underground cable repex is likely to be reasonable.

4.4.5 Service lines

United Energy's forecast

304. United Energy has proposed $23.9m[90] for the Service lines group in its repex forecast for the next RCP. The expenditure profile for the Service lines group comparing the next RCP with prior years is shown in the figure below.

Figure 4.16: Service lines repex by asset category - $m, real 2021



Source: United Energy Reset RIN

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

90 Project based expenditure excluding real cost escalation

Table 4.14: Components of United Energy's proposed Service lines repex for next RCP - $m, real 2021

Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Programs						
Service replacement (planned)	2.3	2.3	2.3	2.3	2.3	11.3
Premise faults service replace	1.4	1.4	1.4	1.4	1.4	6.8
O/h services replaced with u/g	0.0	0.0	0.0	0.0	0.0	0.2
Projects						
Neutral screen services	0.8	0.7	0.6	0.5	0.4	3.0
Twisted PVC services	0.6	0.5	0.5	0.4	0.3	2.3
Incremental pole replacement: identification of additional service lines	0.1	0.1	0.1	0.0	0.0	0.3
Total	**5.1**	**4.9**	**4.8**	**4.6**	**4.5**	**23.9**

Source: EMCa analysis of IR034 UE MOD 4.03 mapping reconciliation. Excludes real cost escalation.

306. United Energy has provided the following documentation with its submission to support its expenditure:

- Unitised volume model (UE MOD 4.02) - which forecasts replacement volumes based on historical replacement volumes for low-cost, high-volume asset interventions of which service lines are a component;
- Expenditure model - comprising its Plant, stations, and lines replacement expenditure (MOD4.03);
- Business case for its service line replacement, [91] provided in support of the service lines group; and
- Asset lifecycle costing model for the planned service line replacement projects.[92]

Our assessment

Proposed replacement volume from unitised volume model is decreasing

307. Of the total, $18.3m is based on the unitised volume model as explained in section 4.3. This is described in the business case as the 'inspection and faults' component. The total expenditure in the business case is $18.6m, which we assume includes the additional services from incremental pole replacement (as identified in Table 4.14).

308. Based on our review of the unitised volume model, we observe the completion of a large replacement program peaking at over 28,000 planned service line replacements in 2012, at an average of 18,000 replacements per annum from 2011-2015.

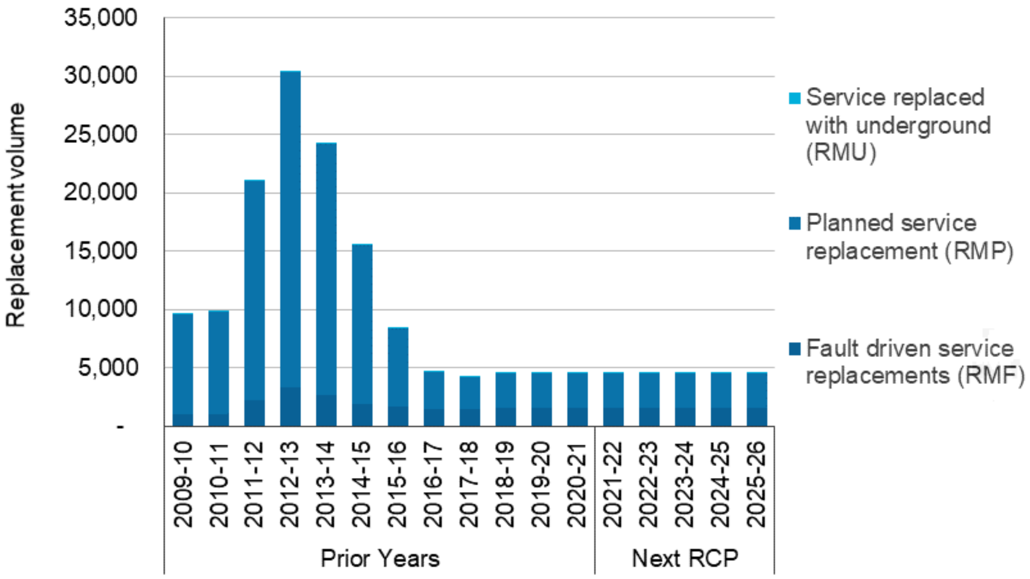
309. The historical and forecast replacement volumes are shown in the figure below.[93] Based on the unitised volume model, the forecast replacement volumes represent the average replacement over the period of 2016-2018 (3 years). The model correctly excludes higher replacement volumes associated with earlier programs, so as not to bias the average.

91 United Energy BUS4.05 Service lines replacement

92 United Energy MOD4.05 Service lines

93 Replacement volumes for each financial year are reflective of the average between two successive calendar years

Figure 4.17: Major components of service line replacement included in unitised volume model



Source: EMCa analysis of unitized volume model UE MOD 4.02. Includes major components of cross arm replacement only

310. A significant reduction to annual fire starts and safety incidents (e.g., resulting in a member of the public receiving an electric shock) associated with service lines is evident in the business case. United Energy attribute this improvement to the previous targeted replacement programs, with most replacements completed in 2011–2016.

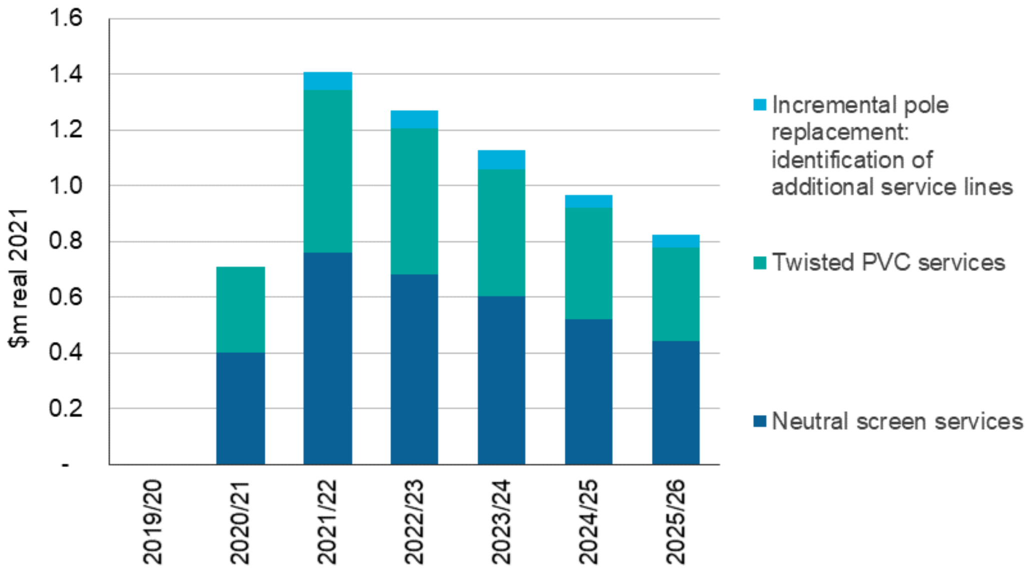
Preferred investment option appears to go further than presented in customer engagement

311. For the next RCP, United Energy has included projects totalling $5.6m in addition to the programs included in its unitised volume model, as shown in Table 4.14. Similar to our assessment of the pole-top structure group, we understand that this is likely to form part of the '*targeted proactive intervention programs*'.[94] We therefore looked for evidence of an AFAP assessment or similar.

312. We provide a summary of the proposed expenditure for service line replacement programs in the figure below. United Energy appear to be commencing these projects in 2020/21, one year prior to the commencement of the next RCP.

94 United Energy Regulatory Proposal, page 64

Figure 4.18: Proposed expenditure for service line replacement programs - $m, real 2021



Source: EMCa analysis of UE MOD 4.03

313. We understand that, as part of United Energy's stakeholder engagement program, it discussed programs that leveraged its smart meter investment to proactively identify hazardous assets. United Energy has included service line replacement programs on the basis that its:[95]

> *'customers were overwhelming supportive of using smart meters to detect and fix faults, where possible.'*

314. On review of the provided business case, this option appears consistent with Option 2 – '*Condition monitoring of the service lines based on smart meter data, with replacement on defect*.' United Energy also considered other options including proactive replacement programs over 5 years, 10 years, and replacement on failure.

315. When we reviewed United Energy's description of the forecasting methods applied to determine the volume of replacement, we found that the replacement volume was determined on the basis of removing the neutral screen type and twisted PVC type service connections within 10 years.[96] This objective appears inconsistent with the representation of customer discussions included in its Regulatory proposal.

Justification for proactive replacement projects is weak

316. United Energy describe its current asset management approach, which we infer already accounts for the removal of hazardous service line assets by:[97]

- 'inspection and testing program to identify replacements based on condition;
- replacement of any remaining neutral screen services by monitoring of neutral service impedance for those which are connected to smart meters, or as they are identified by the normal cyclic inspection program;
- opportunistic replacement of superseded services during any planned shutdown (e.g., when an outage is required to replace a pole top structure, a pole or distribution transformer, any non-preferred services—such as PVC twisted or neutral screens—will be replaced at the same time);

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95 United Energy Regulatory Proposal, page 60

96 United Energy Regulatory Proposal, Table 4.6

97 United Energy BUS 4.05 Service line replacement, p9

- overhead services are undergrounded where there is an identified safety driver, such as in high bushfire risk areas, or crossing an adjacent property with vegetation management issues; and
- ensure compliance with height regulations through replacement of low services or re-tensioning low services.'

317. For the next RCP, United Energy reviewed its intervention options by determining the lowest annual life cycle costs, as expressed in $2019 for each asset type using a discounted cash flow methodology. The preferred options were selected as:

- condition monitoring (AMI) for ABC and bare conductor service lines; and
- proactive replacement (10 years) for neutral screen service lines and PVC twisted service lines. The difference between the annual life cycle cost for proactive replacement and condition monitoring for neutral screen service sand for PVC twisted service lines was marginal.

318. The business case does not explain the assumptions applied in the life cycle costing models. From our review, we find the models are very sensitive to the assumed annual capex assumptions and failure rates. We were not able to establish a clear link between the life cycle costing undertaken on a per asset basis and the recommended option and/or proposed expenditure for the next RCP.

319. Given the marginal result we expected to see, but did not see, that United Energy had undertaken its own sensitivity analysis as part of its review of the intervention options to address these concerns and to clearly demonstrate that the recommended option was superior to the current management option (identified as Option 2).

320. We were not able to find evidence that United Energy had relied on any other information in proposing these projects.

Summary of our assessment

321. Whilst the proactive replacement projects for service lines of the type proposed by United Energy are common across the industry, and likely to require focus within United Energy's network, United Energy has not adequately demonstrated that its current asset management approach (and associated expenditure) will be insufficient to meet its current safety obligations.

322. Accordingly, we consider that United Energy has not justified the extent of the proposed increase to its forecast expenditure for the Service lines repex group.

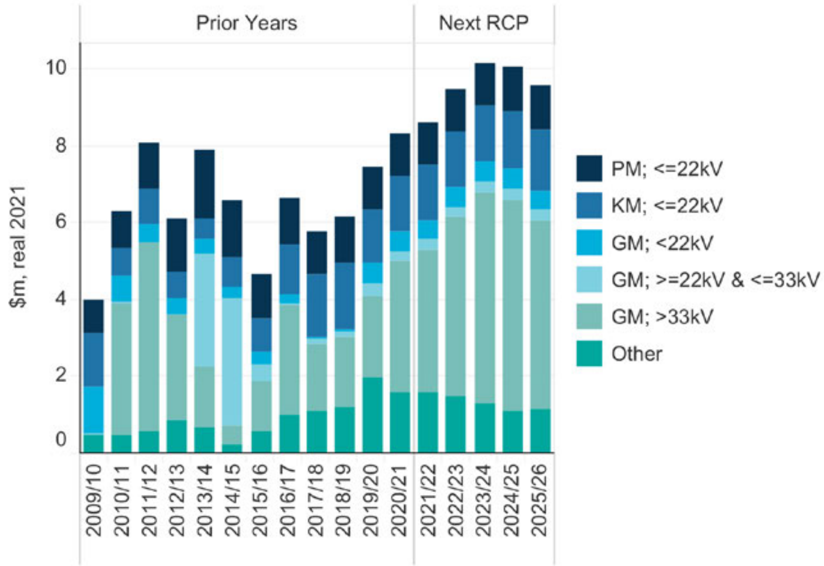
4.4.6 Transformers

United Energy's forecast

323. United Energy has proposed $45.9m[98] for the Transformer group in its repex forecast for the next RCP. The expenditure profile for the Transformer group comparing the next RCP compared with previous years is shown in the figure below.

98 Project based expenditure excluding real cost escalation

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



Source: United Energy Reset RIN

324. The figure above shows that the largest increases in the next RCP are associated with the replacement of substation-related transformers > 33kV. The major components of expenditure by program are shown in the table below (and which reconciles to United Energy's program when real cost escalation is excluded).

Table 4.15: Components of United Energy's proposed Transformer repex for next RCP - $m, real 2021

Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Programs						
Kiosk in service fail 300kVA-2MVA	1.2	1.2	1.2	1.2	1.2	6.2
Transformers in service fail 200 – 500kVA	0.7	0.7	0.7	0.7	0.7	3.5
Transformer failure ground/indoor sub	0.5	0.5	0.5	0.5	0.5	2.7
Transformers in-service fail <200kVA	0.4	0.4	0.4	0.4	0.4	1.9
Replace 66kV transformer bushings	0.2	0.2	0.2	0.2	0.2	0.9
Environmental	0.1	0.1	0.1	0.1	0.1	0.4
Transformers - DSS	0.0	0.0	0.0	0.0	0.0	0.1
Kiosk refurbishment 100kVA-2MVA no switchgear	0.0	0.0	0.0	0.0	0.0	0.0
Allocated programs						
Animal proofing	0.4	0.4	0.4	0.4	0.4	1.9
Projects						
DSS non-unitised replacement RH	0.2	0.2	0.2	0.2	0.2	1.0
Mobile transformer readiness	0.4	0.4	0.2	0.0	0.0	1.0
Transformer overhaul annual program	0.1	0.1	0.1	0.1	0.1	0.7
ZSS OLTC replacement	0.1	0.1	0.1	0.1	0.1	0.7
Wall bushing - replacement	0.1	0.1	0.1	0.1	0.1	0.5
Transformer refurbishment DN #1	0.1	0.0	0.0	0.0	0.0	0.1
Mobile transformer prep: STO	0.0	0.0	0.0	0.0	0.0	0.0
Allocated projects						
Transformer Replacement (16 sites)	3.2	3.7	4.5	4.8	4.4	20.6
SH 6.6kV conversion	0.4	0.8	0.8	0.4	0.0	2.4
Switchboard Replacement (8 sites)	0.2	0.2	0.1	0.2	0.2	0.8
STO station risk management	0.0	0.0	0.0	0.0	0.2	0.2
Total	**8.5**	**9.2**	**9.7**	**9.5**	**9.0**	**45.9**

Source: EMCa analysis of IR034 and UE MOD 4.03 mapping reconciliation. Excludes real cost escalation.

325. United Energy has provided the following documentation with its submission to support its expenditure:

- Unitised volume model (UE MOD 4.02) - which forecasts replacement volumes based on historical replacement volumes for low-cost, high-volume asset interventions of which certain transformers are a component;
- Expenditure model - comprising its Plant, stations and lines replacement expenditure (UE MOD 4.03);
- Forecast method overview for transformer replacement, [99] provided in support of the planned replacement of 16 transformers; and
- Risk monetisation model for transformer and switchgear replacement[100] with accompanying asst risk quantification guide.[101]

99 United Energy BUS4.03 transformer replacement

100 United Energy MOD4.04 Switchgear and transformer risk

101 United Energy ATT139 Asset risk quantification guide

Our assessment

Increased expenditure driven by inclusion of zone substation transformer replacement

326. United Energy proposes to replace 16 zone substation transformers during the next RCP at a total cost of $32.1m. As described in section 4.3, United Energy has allocated a proportion of this expenditure across multiple categories, with $20.6m included for transformers as shown in Table 4.15.

327. The basis for the allocation to RIN categories as described in Table 4.5 is not explained by United Energy. We have assessed the total transformer replacement expenditure.

Age profile indicates that asset management approach is currently managing substation transformers to end of life

328. United Energy has 115 ZS transformers, predominantly 66/22kV and 66/11 kV.

329. United Energy states[102] that its transformer replacement reflects the rising risk of failure, based on its network experience, as the transformer population continues to deteriorate over time. The age profiles for substation transformers (and circuit breakers) support the consideration of assets that are presently beyond expected life or will be by the end of the next RCP.

330. For its proposed substation transformer replacements, United Energy attributed the primary drivers of replacement as the: [103]

- 'rising risk of failure based on our experience as our transformer population continues to deteriorate over time;'
- 'increased consequence of failure due to higher zone substation demand;' and
- 'when the load at risk and growth rate, age or the cost of required site works change, asset replacements may increasingly become the most efficient option.'

331. To develop its forecast replacements, United Energy applies assessments of substation functionality. To do this, United Energy considers the combined assets in each substation (e.g., transformer replacements located at the same substation site are considered together in its risk monetisation assessment). United Energy states that this allows it to reduce outage response times and manage transformers towards failure. We observed that, for most substations, the reduced risk cost following the replacement of one transformer enabled replacement of a second transformer to be deferred.

332. By applying its substation functionality assessment approach, United Energy considers that it achieves benefits by allowing it to diversify plant and equipment, and through this, reduce outage response times.

333. The risks associated with the second transformer deferral are managed by United Energy's investment in mobile substation capabilities together with its ability to relocate transformers following a failure event. For this approach to work effectively, United Energy includes expenditure in its forecast to undertake site preparation to accommodate relocatable transformers. United Energy also continues to make investments in its mobile readiness of targeted substations.

334. The age profile of substation transformers indicates that approximately 23 transformers will be beyond the 60 year expected life by 2026. On the basis of age alone, this would indicate that United Energy's approach has enabled the management of approximately six transformers at end of life, without replacement.

335. In response to our question asking United Energy to explain how it has considered uncertainty in its analysis of transformer replacement planning, it states that:[104]

[102] United Energy BUS 4.03 - Transformer replacement - Jan2020 – Public, page 4

[103] United Energy BUS 4.03 - Transformer replacement - Jan2020 – Public, page 14

[104] United Energy response to information request IR031

- 'the risk of failure is increasing, based on our network experience, as our transformer population continues to deteriorate over time—without intervention, by 2025 there will be 23 transformers in our network that are older than 60-years (having regard to age, in this context, as a broad proxy for condition);
- we do not manage assets so they never fail, but rather, we invest to manage the consequences of failure:
  - we consider and implement non-replacement solutions to reduce risk;
  - we utilise lower cost intervention solutions where efficient to do so, such as relocatable transformers to reduce the consequence of failure (for our network, these are more efficient than a spare and have faster mobilisation); and
- notwithstanding an increase in transformer replacements in the 2021–2026 regulatory period, the number of zone substations where we are managing risk is commensurate with the 2016–2020 regulatory period.'

Basis for its risk monetisation model appears sound

336. For both substation transformers and switchgear, United Energy states that it proposes replacement of an asset when the total value of the underlying risks exceeds the cost of replacing existing infrastructure. To determine the optimum replacement time, United Energy uses a risk monetisation approach and model. United Energy has supported its model with an explanation of its risk monetisation approach[105] and a summary for each project included in the forecast for the next RCP.[106]

337. To determine the probability of failure of its assets United Energy applies a fit to curve approach that considers the following:
- where comprehensive asset data is available, United Energy considers its assets against a relevant Weibull distribution;
- where only partial data is available, United Energy uses a non-parametric method (e.g., Kaplan-Meier) which it considers produces results that better match to its experienced failure rates; and
- consideration is also given to whether other distributions produce a better fit with United Energy's data.

338. For substation plant failures, United Energy calculates the energy at risk using the projected load profile (assessed hourly) for a calendar year, compared with the available capacity in the event of an asset failure. The use of load transfers to lower the load at the affected substation is also assessed. United Energy then calculates:
- the total MWh in the year where the residual load profile exceeds the station's capacity in the event of a plant failure;
- the total MWh in the year where the residual load profile exceeds the station's capacity in the event of two plant failures (two and three transformer stations only); and
- the total MWh in the year where the residual load profile exceeds the station's capacity in the event of three plant failures (three transformer stations only).

339. The reliability and accuracy of the input values to the model are critical to the reliability of the output replacement time. This is especially the case for United Energy substation functionality assessment because the replacement of one unit will affect the optimal replacement timing of other assets. For example, the replacement of one transformer, from a 'whole of substation' perspective, will change the probability and consequences of failure especially for coincident failure risks.

340. The consequences of failure using the five risk categories was straightforward. For selected replacement projects, we tested the key input assumptions for sensitivity to assumptions such as VCR, PoF values and unserved energy, as discussed below.

105 United Energy ATT139 Asset risk monetisation approach

106 United Energy response to information request IR007 - Q11 and Q13 - transformer and switchgear business cases

Options considered for substation transformer replacement are reasonable

341. United Energy considered, costed, and evaluated five options plus a 'maintain status quo' position. United Energy also considered, but rejected, options such as non-network, refurbishment, transformer de-rating and change in components. The options were assessed using United Energy's risk monetisation methodology.

342. We consider that the assessment of risk at the zone substation level enabled United Energy to assess staged replacement options, combined with additional interventions such as monitoring and making the zone substation ready for a relocatable transformer. This approach has provided United Energy with a monetised basis upon which to form decisions to defer transformer and switchboard replacements.

343. The investment in sites to receive a relocatable transformer appears to have allowed United Energy to delay transformer replacement for some sites. However, this has only a short-term effect on the first transformer replacement. The bigger gain is from reducing the whole substation risk to enable the second transformer replacement to be deferred. United Energy has adopted a staged replacement approach, where the analysis may have otherwise determined that more than one transformer should be replaced at a substation, and which is likely to provide a level of optionality.

The model for substation transformers is very sensitive to key parameters that are not adequately justified

344. We have some residual concerns with the models provided to demonstrate the prudent timing of the proposed projects. Firstly, the use of macros inhibited full review of the formulas and logic pathways included in the provided models. However, the assumptions and sensitivity testing appeared to deliver logical results.

345. The inclusion in the models of all substations and the good range of options was helpful in understanding how United Energy manages risk across the transformer (and switchgear) fleet. In many cases, the unplanned replacement risk is driving the risk cost and optimal intervention date.

346. The use of industry standard probability of failure prediction methods was appropriate given United Energy's stated level of knowledge on the health of its transformer and switchboard fleets. We noted that United Energy has tested the standard PoF predictions against its historical failure rates.

347. To calculate the energy at risk cost, United Energy applies a substation relative weighting to the AEMO sector VCR values[107] to determine a substation composite single value of customer reliability. However, when we reviewed the model provided, we did not see evidence of a substation weighting to determine a substation-specific VCR as proposed. In addition to making adjustments for the values of VCR published by the AER as detailed in section 3, we consider the VCR values are likely to be higher than a reasonable level.

348. We note that the timing of the proposed replacements is very sensitive to the demand forecast assumptions. 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 United Energy to test the robustness of the selected option and the timing of the proposed work.

349. For the unserved energy calculation, United Energy applies a weighting of the 10th and 50th percentile demand forecasts with a 30% weighting applied to the 10th percentile and a 70% to the 50th percentile. The energy at risk is calculated for the amount of the demand forecast that is above the N-1 capacity rating of the substation.

350. When adjustments are made to the demand forecast, and/or the probability weightings applied by United Energy, we observe that the proposed timing of a proportion of projects are deferred beyond the end of the next RCP. The projects that are most sensitive to the

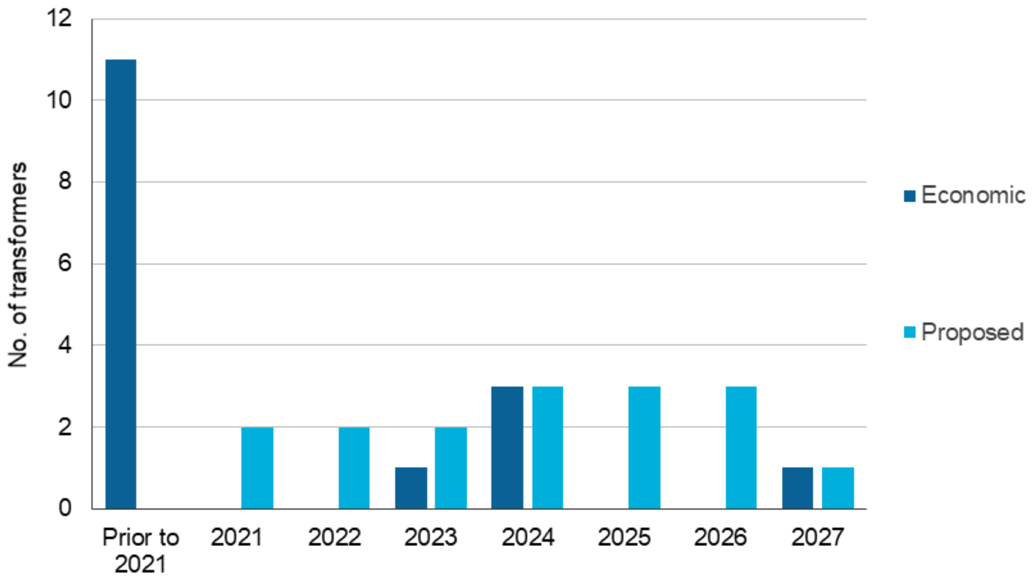
[107] Victorian VCR values in the AEMO final report dated 28 November 2014 which have been escalated using the ratio of March 2014 to March 2019 CPI figures as per the AEMO Application Guide

demand forecast assumptions are those that are proposed to commence towards the end of the next RCP.

Deliverability of the proposed substation transformer replacement is not assured

351. United Energy proposes to undertake a significant replacement program during the next RCP. The risk monetisation model has identified 11 transformers where the economic timing has been determined to be prior to 2021, and a further 5 throughout the next RCP. United Energy has proposed some smoothing to the program as shown in the figure below.

Figure 4.20: Replacement timing of substation transformers

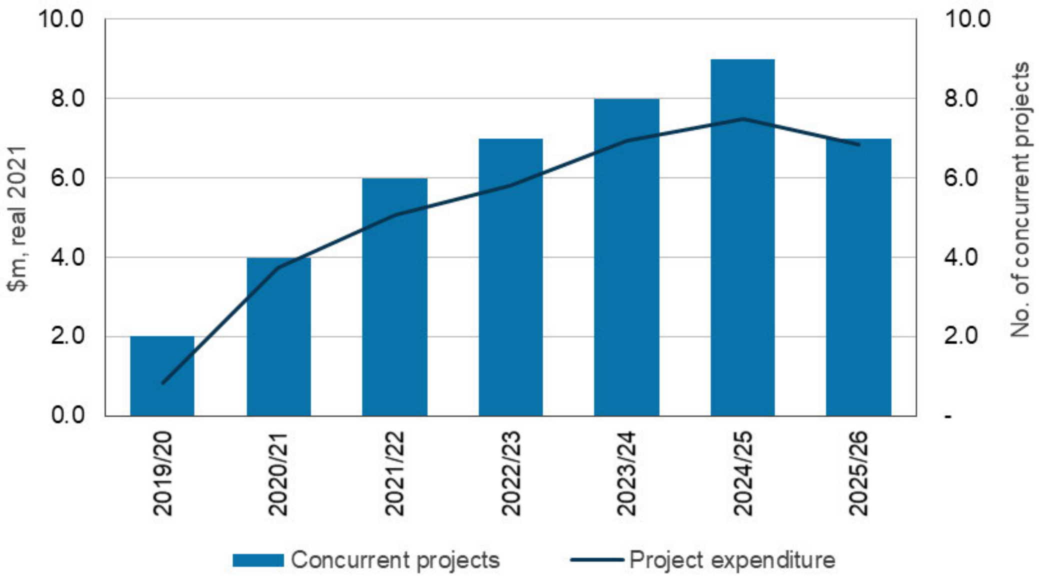


Source: EMCa analysis of UE MOD 4.03

352. Prior to the next RCP, United Energy is undertaking a smaller number of substation replacement projects. Whilst the number of projects forecast to be commissioned in any year is increasing from 2 to 3 per annum, according to the expenditure profiling, United Energy is expecting all of these projects to be implemented over 3 years. This means that at the height of the program, United Energy will be managing 9 concurrent transformer projects at different stages of development and commissioning.

353. We show this profile, along with the increasing expenditure profile in the figure below.

Figure 4.21: Proposed expenditure and number of concurrent projects for transformer replacement program



Source: EMCa analysis of UE MOD 4.03

354. We are concerned about United Energy's ability to deliver this program in the next RCP. As a result, we expect that a proportion of the project will be delayed or deferred into the subsequent RCP. The most likely candidates for roll over are those that are scheduled to commence at the end of the next RCP, such as CRM and MC substations.

355. We asked United Energy to provide an explanation of its delivery strategy and plan, including evidence of an assessment of its ability to deliver the proposed step increase in forecast expenditure at a total level. In response, United Energy described its outsourced model including longer-term contracts, projects to tender large capital works, and approved materials schedules. In addition:[108]

> *'We also have a demonstrated history of delivering large and complex capital programs, including during the 2011–2016 regulatory period (i.e., the value of our replacement program was consistent with that forecast in the 2021–2026 regulatory period, once our environment spend is removed), and the roll-out of advanced metering infrastructure.'*

356. We expect that the change in composition of the program, specifically the introduction of additional large replacement projects in existing substation sites (for both transformers and switchgear) is likely to present the primary delivery challenge, rather than any change in total expenditure level.

357. United Energy has commissioned, or will commission, relocatable (mobile) transformers at all of the sites where transformers are planned for replacement in 2025 and 2026, with the majority of those planned for commissioning in 2025 – totalling 7 sites. This provides United Energy with further risk mitigation, should a failure occur at these sites.

Cost efficiency has not been adequately demonstrated

358. United Energy provided little detail on the costs for the works, other than to advise that they were based on historical costs. We consider it likely that United Energy will reduce these costs in practice as it captures the efficiency gains made in the current RCP and secures additional discounts on equipment and for design time efficiencies associated with the step increase in its proposed substation replacement program.

108 Response to information request IR016

Non-substation transformer replacement appears reasonable

359. In response to a request to detail United Energy's forecasting methodology for non-zone substation transformers:[109]

> *'Analysis of our historical performance shows there is no clear trend for any non-zone substation distribution transformer category (i.e., annual failures and replacements vary each year). Our volume forecast, therefore, reflects an average of historic replacements.'*

360. Based on our review of the composition of the forecast, the distribution-based transformer replacement appears consistent with the historical trend. We were not provided with a copy of the asset class strategy or operational plans that include distribution transformers to confirm any specific strategies being targeted by United Energy in the next RCP.

361. In the absence of better information, United Energy appears to be basing its justification on historical trend and by reference to the outcome of the AER's repex model for non-substation transformer expenditure. Based on our review of the historical trend, and the level of proposed expenditure, this approach is likely to result in a reasonable estimate of requirements.

A proportion of the proposed expenditure is related to other projects and programs

362. United Energy has included $1.9m for animal proofing within the transformer group, which totals $7.1m across all expenditure categories for the next RCP. As described in section 4.3, we include our assessment of the other components of proposed expenditure in the underground cable and switchgear group sections of this report.

Summary of our assessment

363. Given the size of United Energy's transformer replacement program, we consider it likely to see variations from the proposed plan as the next RCP progresses. We consider that a number of transformers will likely roll-over into the next RCP, with the most likely candidates being CRM and MC substations.

364. We tested the robustness of United Energy's risk monetisation models that were provided in support of its substation transformer expenditure. We found that when adjustments are made to the demand forecast assumptions in the risk models, the timing for a number of additional substation projects may be deferred. This has a greater impact on the forecast expenditure for the next RCP due to the proposed timing of expenditure, with deferral likely to amount to up to 25% of the total proposed expenditure.

365. On balance, we consider that United Energy will incur a level of expenditure on Transformer replacement at a level lower than it has proposed.

366. For the remainder of the project expenditure, excluding network faults, we were not provided with sufficient information to assess this in great detail. However, based on our assessment of the expenditure and historical trend, the forecast replacement levels and associated expenditure are likely to be reasonable.

4.4.7 Switchgear

United Energy's forecast

367. United Energy has proposed $70.7m[110] for the Switchgear group in its repex forecast for the next RCP. The expenditure profile for the Switchgear group comparing the next RCP with prior years is shown in the figure below.

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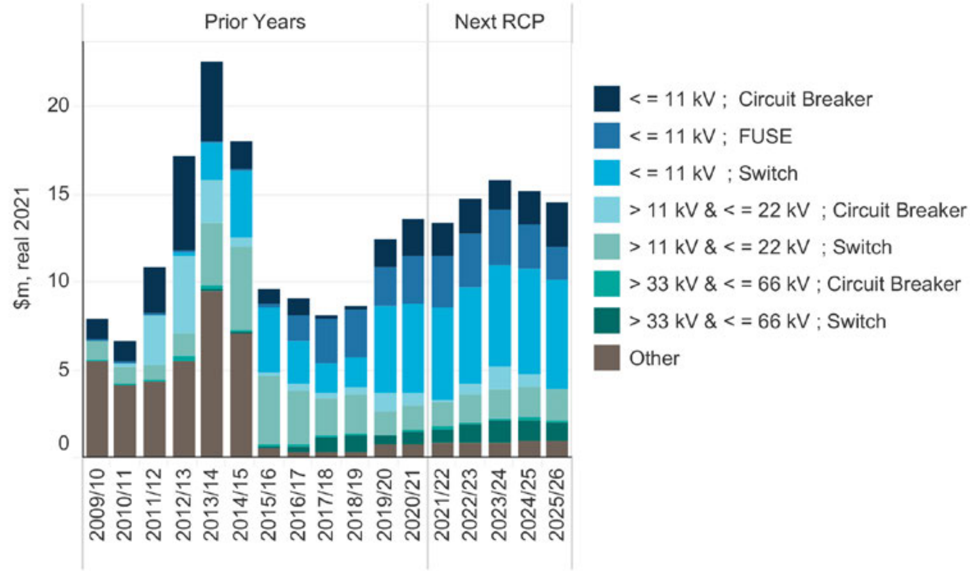
[109] Response to information request IR013

[110] Project based expenditure excluding real cost escalation

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



Source: United Energy Reset RIN

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

Table 4.16: Components of United Energy's proposed Switchgear repex for next RCP - $m, real 2021

Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Programs						
Gas switches (age replacement)	2.8	3.0	3.2	3.4	3.6	16.0
Indoor/kiosk switchgear, RMU age fault	1.7	1.7	1.7	1.7	1.7	8.4
LV isolators (set of 3)	1.3	1.3	1.3	1.3	1.3	6.3
Fuse unit replacement (set of 3)	1.2	1.2	1.2	1.2	1.2	6.0
Fuse/junction box replacement	0.5	0.5	0.5	0.5	0.5	2.3
LV switchgear replacement	0.4	0.4	0.4	0.4	0.4	1.9
NEW MGS Switch installation	0.3	0.3	0.3	0.3	0.3	1.7
HV isolators (set of 3)	0.1	0.1	0.1	0.1	0.1	0.6
ACR replacements	0.1	0.1	0.1	0.1	0.1	0.6
Replace Dist. Line capacitor switch	0.1	0.1	0.1	0.1	0.1	0.4
LV isolator (single)	0.0	0.0	0.0	0.0	0.0	0.0
Allocated programs						
Animal proofing	0.8	0.8	0.8	0.9	0.9	4.2
Projects						
EDO fuse replacement	1.2	1.2	1.3	0.7	0.0	4.3
CB replacement	0.2	0.2	0.2	0.2	0.1	0.8
Allocated projects						
Switchboard Replacement (8 sites)	1.9	1.9	1.6	1.8	2.4	9.5
Transformer Replacement (16 sites)	0.7	0.8	1.0	1.0	1.0	4.5
Switchyard Replacement (3 sites)	0.0	0.6	1.2	0.7	0.0	2.6
SH 6.6kV conversion	0.1	0.2	0.2	0.1	0.0	0.5
STO station risk management	0.0	0.0	0.0	0.0	0.0	0.0
Total	**13.2**	**14.3**	**15.1**	**14.4**	**13.7**	**70.7**

Source: EMCa analysis of IR034 UE MOD 4.03 mapping reconciliation. Excludes real cost escalation

369. United Energy has provided the following documentation with its submission to support its expenditure:

- Unitised volume model (MOD4.02) - which forecasts replacement volumes based on historical replacement volumes for low-cost, high-volume asset interventions including components of switchgear;
- Expenditure model - comprising its Plant, stations and lines replacement expenditure (MOD4.03);
- Forecast method overview for switchgear replacement,[111] provided in support of the planned replacement of switchboards and switchyards for the next RCP; and
- Risk monetisation model for transformer and switchgear replacement,[112] with accompanying asset risk quantification guide.[113]

[111] United Energy BUS 4.04 Switchgear replacement

[112] United Energy MOD 4.04 Switchgear and transformer risk

[113] United Energy ATT139 Asset risk quantification guide

Our assessment

Increased expenditure is driven by inclusion of zone substation switchgear replacement

370. During the next RCP, United Energy proposes to replace switchboards at 8 substation sites for a total cost of $15.9m and switchyard replacements at 3 sites for a total cost of $3.7m, as outlined in the table below.

Table 4.17: Switchgear replacement projects - $m, real 2021

Project	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Switchboard replacement	3.1	3.1	2.7	3.0	4.0	15.9
EL	*0.1*	-	-	-	-	*0.1*
SR	*1.0*	-	-	-	-	*1.0*
BT	*1.4*	*1.0*	-	-	-	*2.4*
EM	*0.6*	*1.5*	*0.9*	-	-	*3.1*
EW	-	*0.5*	*1.4*	*0.8*	-	*2.7*
BR	-	-	*0.4*	*1.5*	*1.1*	*2.9*
BU	-	-	-	*0.4*	*1.5*	*1.8*
OE	-	-	-	*0.4*	*1.4*	*1.8*
Switchyard replacement	0.1	0.9	1.8	1.0	-	3.7
HT	*0.1*	*0.6*	*0.5*	-	-	*1.2*
DC	-	*0.2*	*0.8*	*0.6*	-	*1.7*
GW	-	*0.1*	*0.4*	*0.4*	-	*0.8*
Total	**3.2**	**4.0**	**4.5**	**4.0**	**4.0**	**19.6**

Source: EMCa analysis of IR034 UE MOD 4.03 mapping reconciliation. Excludes real cost escalation

371. As described in section 4.3, United Energy has allocated a proportion of this expenditure across multiple categories, with $9.5m and $2.6m being allocated to the switchgear group for switchboard replacements and switchyard replacement respectively (as shown in Table 4.16).

372. The basis for the allocation as described in Table 4.5 (and as shown in Table 4.16 for switchgear) is not explained by United Energy. We assess the total project expenditure for switchboard and for switchyard replacement as detailed in the table below.

Drivers for switchgear replacement are reasonable

373. United Energy describes the main drivers of replacement of switchgear as:[114]

> *'Asset condition based on inspection regime, operational experience and/or asset failure for distribution or overhead line switchgear. It is noted a portion of assets within such asset categories are proactively replaced due to a higher likelihood to cause safety (injury and/or bushfire) concerns or jurisdictional directives; and*
>
> *Asset condition and risk profile based on inspection and testing regime, operational experience such as fault history, value of lost load, emergency cost, and/or asset failure for zone substation switchgear.'*

374. We note that this includes a level of proactive replacement where United Energy considers there is a higher likelihood of safety issues. United Energy states that it has not changed its

[114] United Energy RIN016 Repex RIN response

asset management approach for distribution switchgear. Whereas for substation switchgear, United Energy states that it has prioritised locations for replacement and this has led to an increased focus on indoor switchgear replacement over outdoor circuit breaker replacements.[115]

375. In response to our question to explain how United Energy has considered uncertainty in its analysis of switchgear replacement planning, in the context of the changing and uncertain nature of the electricity network, United Energy states that:[116]

- 'the risk of failure is increasing, based on our network experience, as our zone substation switchgear population continues to deteriorate over time—in the past decade we have experienced an increase in the rate of failure events across our fleet, resulting in extended outages (months) and high repair costs;
- we do not manage assets so they never fail, but rather, we invest to manage the consequences of failure:
  - we consider and implement non-replacement solutions to reduce risk;
  - we utilise spare circuit breakers for some of our asset fleet to reduce the consequence of failure; and
  - our outdoor switchgear is lower risk than indoor switchgear, so are only replaced when other works occur on site (and even then, works are targeted to specific circuit breakers in the outdoor switchyard).'

Application of the risk model for switchgear replacements is reasonable

376. For both substation transformers and switchgear, United Energy states that it proposes replacement of an asset when the cost of replacing existing infrastructure exceeds the total value of the underlying risks. To determine the optimum replacement time, United Energy uses a risk monetisation approach and model. United Energy has supported its model with an explanation of its risk monetisation approach[117] and a summary for each project included in the forecast for the next RCP.[118]

377. By applying a joint and conditional probability approach, United Energy quantifies circuit breaker or switchboard failure at an overall level of risk for the substation. Using this approach United Energy includes consideration of available asset redundancy, ability to transfer load and response times. United Energy also considers potential costs associated with multiple interventions for individual asset replacements, including the impact this would have on reliability.

378. Whilst United Energy obtains an initial view of asset failure rates from its historical data, it also considers failure type ratios from relevant industry sources. When applying its joint and conditional probability approach, United Energy derives failure predictions using Kaplan-Meier analysis[119] and ratios of independent and common-cause failures from its actual observed failure data.

379. Whilst its data on asset health could be improved, it has applied standard industry approaches to develop its predicted failure rates.

Similar to the transformer group, the models are sensitive to key parameters that are not adequately justified

380. We have some residual concerns with the models provided to demonstrate the prudent timing of the proposed projects. Firstly, the use of macros inhibited full review of the formulas and logic pathways included in the provided models. However, the assumptions and sensitivity testing appeared to deliver logical results.

115 United Energy RIN016 Repex RIN response

116 Response to information request IR031

117 United Energy ATT139 Asset risk monetisation approach

118 Response to information request IR007 - Q11 and Q13 - transformer and switchgear business cases

119 The Kaplan–Meier estimator is a non-parametric statistic used to estimate the survival function from lifetime data

381. When we applied revised assumptions to the model (to reflect the concerns that we expressed in the transformer group) for the switchgear group of expenditure, we found that the optimal date for replacement was deferred. However, the input assumptions needed to be unreasonably modified to shift the projects beyond the next RCP.

United Energy has considered a reasonable set of options for its analysis of substation switchgear replacements

382. United Energy has costed and evaluated options to replace a single bus section and to replace two bus sections with either the same or different types of circuit breakers. A 'maintain status quo' option was developed as the comparator to determine the optimal timing for intervention. The circuit breakers identified to be replaced are based on United Energy's view of those that presented the highest risk due to condition, lack of redundancy, and inability to transfer load.[120] United Energy also considered, and rejected, options to install online monitoring equipment, non-network solutions and refurbishment alternatives for the projects included in the forecast. We consider that this is reasonable for these sites.

383. According to its business case,[121] United Energy gives further consideration to a range of delivery factors following the outcome of the risk monetisation model. These factors include alignment with other projects (such as the timing of augmentation works, or protection relay upgrades) to identify deliverability synergies or to minimise customer impacts.

384. United Energy considers that the use of its risk monetisation approach has allowed it to reduce the proposed asset replacements below what they would otherwise have been: [122]

> *'Our risk modelling has allowed us to better target investment and defer a number of asset replacements; this approach is somewhat invisible in our proposal as no expenditure is requested. We have tried to develop a balanced plan that is deliverable and in the interests of customers.'*

385. We found evidence that United Energy has adopted a staged approach to replacement which is likely to generate a prudent forecast for the selected projects. For example, for Heatherton replacement, United Energy proposes to replace one 22kV bus and perform targeted circuit breaker replacement in 2023. This work is planned to coincide with relay and control building replacement works.

A proportion of the proposed expenditure is related to other projects and programs

386. United Energy has included \$5.0m as a result of the allocation of expenditure from the transformer expenditure group to the switchgear group, relating to transformer replacements, as described in section 4.3. We have included the assessment of this expenditure in the transformer group.

387. United Energy has also included \$4.2m for animal proofing within the switchgear group. Animal proofing is a common activity undertaken by DNSPs to mitigate against animal-related faults and interruptions to customers. This includes possum guards on poles, bird and bat protection on pole-top structures and pole-top assets (including switchgear and transformers). United Energy describes the planned activities as:

- Minor animal proofing (Minor) HV/LV;
- Possum protection;
- Possum protection sw, s/s, chp; and
- Bird/animal proofing on network.

388. We have not been provided with a basis on which to assess whether the level of the proposed expenditure is reasonable. Expenditure allocations for animal proofing across

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120 United Energy response to information request IR007 - Q11 and Q13 - transformer and switchgear business cases, p56

121 United Energy response to information request IR007 - Q11 and Q13 - transformer and switchgear business cases

122 United Energy response to information request IR007 - Q11 and Q13 - transformer and switchgear business cases

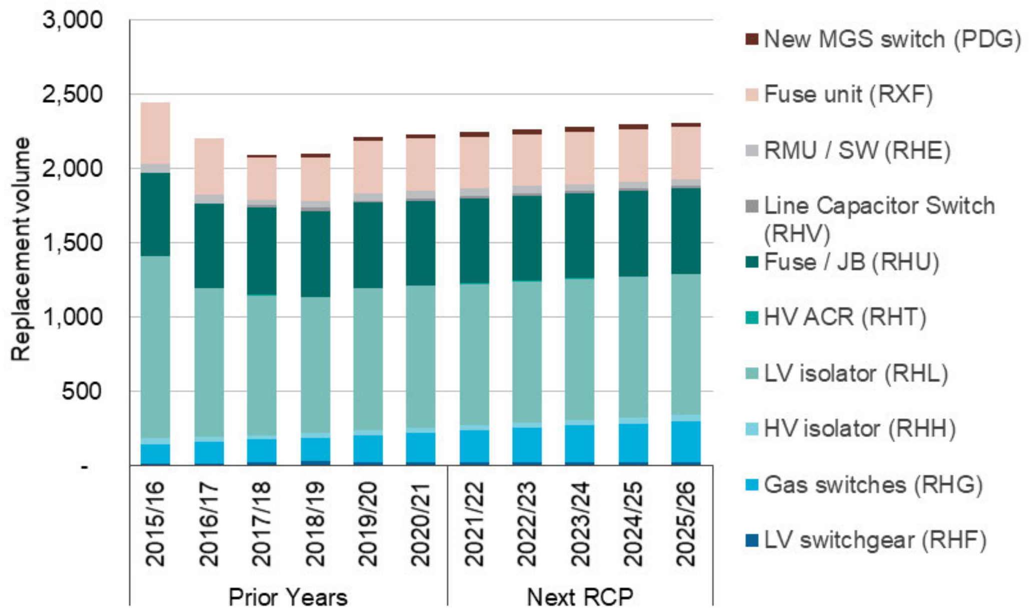
three categories (switchgear, transformers and underground cable) also make it difficult to establish a trend.

Program-based expenditure has not been adequately supported

389. United Energy has included $44.2m of program-based expenditure derived from its unitised volume model as discussed in section 4.3.

390. With the exception of gas switch replacements which adopts a linear trend, the remaining categories adopt an average of historical volumes. We show the replacement volumes in the figure below, where the increasing trend associated with the gas switch replacements can be seen.

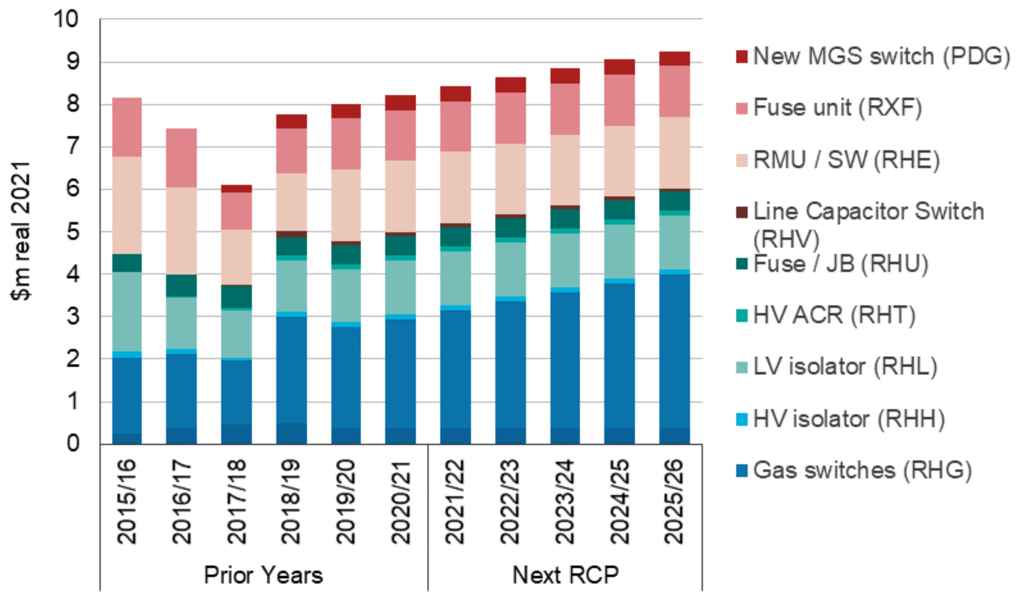
Figure 4.23: Program based replacement volumes



Source: EMCa analysis of UE MOD 4.02 unitised volume model

391. We show the corresponding historical and forecast expenditure for each activity in the figure below. It is clear that the step increase in expenditure evident from 2019-20 in Figure 4.22 is driven by the inclusion of targeted replacement projects and not the program-based expenditure.

Figure 4.24: Historical and forecast program-based switchgear expenditure - $m, real 2021



Source: EMCa analysis of UE MOD 4.03

392. The increases in forecast expenditure observed above the historical levels of expenditure which United Energy has been incurring to maintain the current level of performance, are primarily associated with gas switch replacement and the new MGS switch installations, totalling $17.7m for the next RCP. We have not been provided with compelling justification for these upward trends.

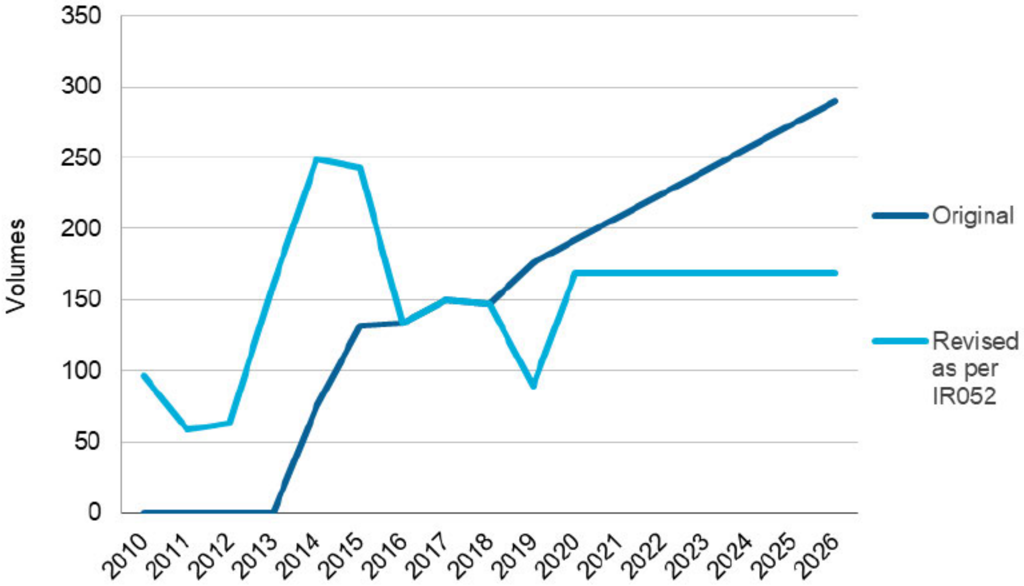
393. For the gas switch replacement program, the proposed expenditure for the next RCP is 150% higher than expenditure for the last 5 years. United Energy describes the trend as being reflective of the increasing number of gas switches in the network that are within the 30-35 year age bracket and which are starting to exceed their design life. As for all replacement decisions, we would expect to see further analysis beyond the use of an age-based replacement approach, including cost benefit analysis and demonstration of AFAP or similar. This supporting justification is required to demonstrate that this program is reflective of a prudent level of replacement.

394. United Energy has subsequently clarified that additional historical replacement volumes had not been included[123] for its gas switch replacement (material code RHG).[124] United Energy has provided additional data which is compared with the original data in the figure below.

[123] Due to classification of historical replacements against a now superseded material code that is not used in the unitised volume model

[124] Response to information request IR052

Figure 4.25: Comparison of original to revised replacement volumes for RHG – gas switch replacement



Source: EMCa analysis of response to information request IR052

395. As a result of recognising the replacement volumes prior to 2014, the forecasting method changed from a linear trend to an average, with a corresponding decrease in forecast replacement volumes for the next RCP. United Energy has proposed a reduction to the expenditure forecast of $5.1m for the next RCP associated with the reduced replacement volume.

Targeted replacement projects have not been adequately justified

396. United Energy has included two further targeted projects, which are both 100% allocated to the switchgear group, totalling $5.1m as shown in the table below.

Table 4.18: Targeted switchgear replacement projects – $m, real 2021

Project	2021/22	2022/23	2023/24	2024/25	2025/26	Total
EDO fuse replacement	1.2	1.2	1.3	0.7	-	4.3
CB replacement	0.2	0.2	0.2	0.2	0.1	0.8
NP 66kV	*0.1*	-	-	-	-	*0.1*
FSH 66kV	*0.1*	*0.1*	-	-	-	*0.2*
HT 66kV	-	*0.1*	*0.1*	-	-	*0.2*
SV 66kV	-	-	*0.1*	*0.1*	-	*0.2*
DVY 66kV	-	-	-	*0.1*	*0.1*	*0.2*
Total	**1.3**	**1.4**	**1.5**	**0.8**	**0.1**	**5.1**

Source: EMCa analysis of IR034 UE MOD 4.03 mapping reconciliation. Excludes real cost escalation

397. We have not been provided with sufficient justification to support the inclusion of the proposed EDO fuse replacement project. The forecast expenditure for the EDO fuse replacement project is proposed to increase from $0.5m in 2019/20 to $1.3m in 2023/24, at an annual average of $0.9m over the next RCP. As a single project description, we were not able to ascertain unit costs or derive the proposed replacement volumes.

398. In response to our request for further information on the non-substation switchgear forecast, United Energy explained that the EDO replacement program is a new proactive replacement program:[125]

> *'Given the risks noted above, we developed a replacement program to remove all EDO fuses from our network by the end of the 2024/25 financial year, as part of our cyclic pole inspection program. The assessment of this program considered historical failure and fire start rates, fire prediction modelling to quantify consequence risks, and reliability data to assess the probability of such events. This program is consistent with our general duties obligations to minimise risk as far as practicable; and*
>
> *Our project assessment also considered alternative mitigation options, including the retro-fitting of fault-tamers. The least-cost intervention option is our proposed EDO program.'*

399. We were not provided with the project assessment referred to by United Energy or a cost-benefit analysis that supported the safety benefits. Based on the proposed expenditure the proposal is likely to present a lower cost option than either replacement with existing technologies or replacement with alternate technologies including fault-tamers. However, in the absence of: (i) consideration of the existing fuse replacement programs that form part of the program-based expenditure; and/or (ii) demonstration of the cost-benefit analysis, the proposed expenditure is likely to be higher than a prudent and efficient level.

400. United Energy has subsequently confirmed that the forecast for EDO fuses (material code RXF) did not include the proactive replacement program. United Energy has estimated that the annual reduction in expenditure for the EDO fuse program (material code RXF) is $0.25m, with a total reduction to the EDO fuse program of $1.24m for the next RCP.[126]

401. We calculate that, based on the unit rate of $3,421, this is equivalent to a reduced replacement volume of approximately 362 units, equivalent to a 20% reduction of the original replacement volume included in the forecast.

402. For circuit breakers, United Energy is seeking to replace its highest risk category 11kV circuit breakers due to their design, condition, age, and failure history. The expected life for zone substation switchgear is typically 40 years.[127] The age profiles for circuit breakers support the consideration of assets that are now beyond expected life or will be by the end of the next RCP.

403. United Energy has forecast replacement of 122 units out of approximately 300 that will be beyond the 40-year operating life expectancy in the next RCP. We consider that this level of forecast expenditure is reasonable.

Summary of our assessment

404. United Energy has proposed a step increase in switchgear group, that commenced around 2019/20 and continues into the next RCP, largely driven by increases to substation switchgear replacement.

405. We found that United Energy has supported the proposed replacement of the nominated switchboards and switchyards using its risk monetisation models for substation switchgear replacement. We found evidence that United Energy has effectively considered options, staging and other delivery considerations to effectively manage risk. We consider that the switchboard replacements will proceed as planned to manage United Energy's exposure to increasing risk cost and to ensure that reliability is maintained.

406. When considered alongside the transformer replacement program, United Energy is undertaking a large program of brownfield switchgear replacement in older substations and which may result in delays to the program as proposed. We have not seen adequate evidence to address the risk of potential delays, despite United Energy's assertions that the

125 Response to information request IR013

126 Response to information request IR052

127 United Energy BUS 4.04 - Switchgear replacement - Jan2020 – Public, page 5

work will be delivered by competitive tender, and which may indicate that the proposed expenditure may be above the level that will actually be incurred by United Energy.

407. United Energy has not provided sufficient details of its cost estimating methods or demonstrated that the processes applied by United Energy will ensure that the cost estimates relied upon in developing its forecast expenditure are efficient.

408. United Energy submits that its cost estimates are largely based on previous project delivery costs; however, we have not seen the sample set used to ascertain the reasonableness of the forecast. The cost estimates are not subject to external review other than at time of tender and are at an early stage of project development. As the project planning develops, and the number of replacement projects increases relative to its previous replacement program, we consider that United Energy may find opportunities for further efficiency in delivery.

409. For the program-based and targeted replacement projects, we found examples of where key components were driving increases to the forecast expenditure. In these cases, we were not provided with sufficient information to justify the expenditure in accordance with the Rules. In light of subsequent corrections to the expenditure forecast for gas switch replacement and EDO fuses provided by United Energy, which result in reducing the expenditure forecast in these areas, we consider that the corrected forecast has addressed our primary concerns.

410. We remain concerned that these cases highlight that the forecasting method may not have been reviewed to the extent claimed by United Energy, and that other areas of potential duplication within switchgear or other asset categories may persist.

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

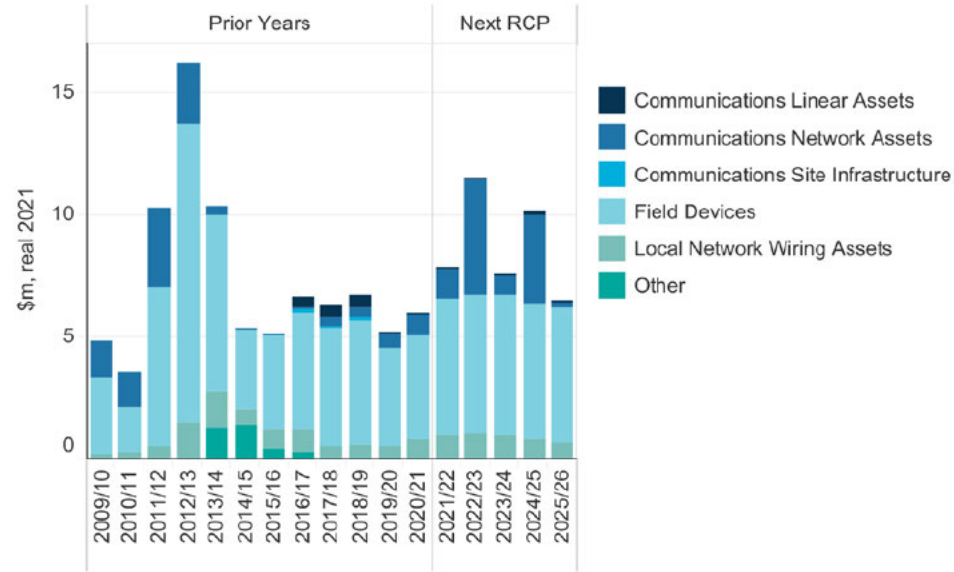
4.4.8 SCADA, network control and protection

United Energy's forecast

412. United Energy has proposed $42.0m[128] for the SCADA, network control and protection group in its repex forecast for the next RCP. The expenditure profile for the SCADA, network control and protection group, comparing the next RCP with prior years is shown in the figure below.

128 Project based expenditure excluding real cost escalation

Figure 4.26: SCADA. Network control and protection repex by asset category - $m, real 2021



Source: United Energy Reset RIN

413. The figure above shows an increase in expenditure for the next RCP compared with historical expenditure, with the largest forecast increases associated with communications network assets, followed by field devices. The major components of expenditure and program by construction type are shown in the table below (and which reconcile to United Energy's program when real cost escalation is excluded.)

Table 4.19: Components of United Energy's proposed SCADA, network control and protection repex for next RCP - $m, real 2021

Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Programs	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.7**
Replace Dist. Line Capacitor Controller	0.1	0.1	0.1	0.1	0.1	0.7
Project groupings[129]	**7.0**	**10.3**	**6.3**	**8.6**	**5.1**	**37.3**
Relay Replacement	4.8	4.5	4.5	4.1	3.5	21.4
UE MAN Infra	0.2	1.9	0.0	2.2	0.0	4.3
ZSS DC replacement annual program	0.8	1.0	0.8	0.7	0.5	3.9
RTU Replacement	0.9	0.9	0.8	0.5	0.2	3.2
Other	0.1	0.2	0.2	1.2	0.9	2.6
Radio and Remote Replacement	0.1	1.7	0.0	0.0	0.0	1.9
Allocated projects	**0.7**	**0.8**	**0.9**	**0.9**	**0.8**	**4.1**
Transformer Replacement (16 sites)	0.5	0.5	0.6	0.7	0.6	2.9
Switchboard Replacement (8 sites)	0.2	0.2	0.1	0.2	0.2	0.8
SH 6.6kV conversion	0.1	0.1	0.1	0.1	0.0	0.3
STO station risk management	0.0	0.0	0.0	0.0	0.0	0.0
Total	**7.8**	**11.2**	**7.3**	**9.6**	**6.1**	**42.0**

Source: EMCa assignment to project groupings based on project titles included in UE MOD 4.06. EMCa analysis of IR034 UE MOD4.03 mapping reconciliation. Excludes real cost escalation

414. United Energy has provided the following documentation with its submission to support its expenditure:

129 The projects included by United Energy have been grouped to assist assessment

- Unitised volume model (UE MOD 4.02) - which forecasts replacement volumes based on historical replacement volumes for one program only; and
- Expenditure model - comprising a list of projects included as part of its Plant, stations and lines replacement expenditure (UE MOD 4.03).

415. United Energy 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 our review of other supporting information.[130]

Our assessment

Increased expenditure from current levels is not adequately explained

416. According to United Energy,[131] the expenditure associated with the SCADA, network control and protection group needs to increase from $31.1m in the current RCP to $42.0m in the next RCP. United Energy describes[132] the main drivers of replacement as technology obsolescence, lack of market support, technology disruption, and asset failure. However, United Energy has not provided a description of the strategies which have led to proposing this increase in expenditure.

United Energy has included a proportion of its proposed relay replacement based on assessed condition of the relays

417. We requested summary justification documents (i.e., business cases or similar) for the total forecast expenditure in this group including details of scope, key drivers, 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 United Energy to provide a copy of any modelling outputs used to determine the proposed expenditure.

418. In response to our request, United Energy provided a copy of its protection and control monetisation model[133] and its asset life cycle strategy.

419. United Energy advised that the forecast expenditure in the next RCP reflects two key drivers: (i) replacements driven by the condition of the secondary assets; and (ii) replacements driven by the timing of primary asset replacements.

420. In its response, United Energy outlines 16 relay replacement projects of which: (i) 7 are driven by switchgear replacement (including 2 in-flight projects); and (ii) a further 9 are driven by condition (risk). The total expenditure is $21.4m as shown in Table 4.19.

421. United Energy describes that:[134]

> *'replacements driven by the condition of the secondary assets are based on a risk-monetisation approach that is consistent with the AER's asset replacement practice note and our asset risk quantification guide (submitted with our regulatory proposal, UE ATT139). Under this approach, the 'maintain status-quo' option is to continue ongoing planned, preventative maintenance, and run the asset to failure. The risk monetisation model is attached, as 'UE - IR013 - protection and control monetisation model'.'*

422. The model inputs are similar to those that have been applied to other substation replacement projects. United Energy also applied a different hazard function to the different relay technologies to reflect different probabilities of failure. The preferred option is selected from assessment of the risk cost of status quo and increased maintenance relative to the annualised replacement cost.

130 Including the Regulatory proposal, RIN016 and asset strategy documents

131 United Energy Regulatory Proposal Table 4.11

132 United Energy RIN response RIN016

133 Response to information request IR013 – protection and control monetisation model

134 Response to information request IR013

423. The projects arising from the outputs of the protection and control monetisation model total $17.3m over the next RCP. The capital costs in the model reflect total project costs and include control building costs, where applicable. Subject to the technology being used, the asset life is likely to be lower than the 25-year asset life that has been assumed. The model is very sensitive to the selection of this factor.

424. We observe that United Energy's modelling approach in this group is similar to the approach undertaken for substation replacement projects. Accordingly, we consider that the input assumptions relied upon in the model are likely to be subject to similar concerns, leading us to conclude that some of the input assumptions may be overstated (i.e., lead to overstating the expenditure required).

425. The model outputs indicate that the projects proposed for replacement are at, or past, the optimal replacement date. We expect that the projects proposed represent a subset of the relay population.

426. Our assessment is hindered by not seeing how the risk has been assessed across the fleet of protection relays, or indeed other assets within the SCADA, network control and protection group. The models are provided for the nine projects only. We were not provided with information to review the aggregate risk or to understand how the replacement projects were selected by United Energy. Accordingly, we do not have sufficient information to justify the level of forecast expenditure as being reflective of a prudent and efficient level.

Switchboard replacements drive a proportion of expenditure

427. United Energy advised that the proposed replacement of switchboards in the next RCP will also result in changes to protection and control systems, and that it is more economic to provide new relays fitted and supplied along with the new switchgear.

428. To the extent that the switchboard replacements proceed as planned, it is reasonable to include the protection and control expenditure associated with provision of new relays and associated equipment in parallel.

Inadequate justification for the remaining parts of the forecast

429. Other than the description of the projects in the project list included in the expenditure models, we have not been provided with the drivers for the remaining projects, including scope definition and/or options analysis. We found that the protection and control model was limited to assessment of the 9 projects driven by condition (risk).

430. Accordingly, we consider that United Energy has not adequately justified that the proposed expenditure is reflective of a prudent and efficient level, including how the replacement projects were selected.

A proportion of the proposed expenditure is related to other projects and programs

431. United Energy has included $4.1m as a result of the allocation of expenditure from other categories, as described in section 4.3. This will be included in the assessment of expenditure categories that best align with the activities being proposed.

Summary of our assessment

432. We did not find sufficient evidence as required under the NER, and as described by the AER's capital expenditure assessment guideline, to support inclusion of the proposed expenditure. Specifically, the basis for the increases primarily associated with communications-related projects has not been sufficiently established.

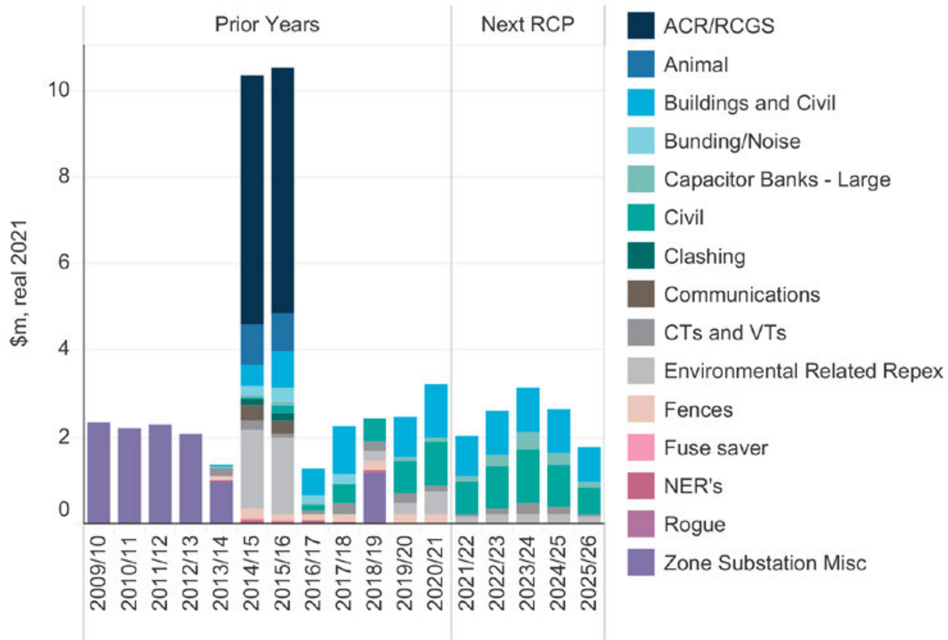
433. We consider that United Energy has not justified the extent of the proposed increase to its forecast expenditure for SCADA, network control and protection repex.

4.4.9 Other repex

United Energy's forecast

434. United Energy has proposed $11.9m[135] 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 prior years is shown in the figure below.

Figure 4.27: Other repex by asset category - $m, real 2021



Source: United Energy Reset RIN

435. The figure above shows that the proposed expenditure for the next RCP is similar to the historical trend from the current RCP. The major components of expenditure are shown in the tables below (and which reconcile to United Energy's program when real cost escalation is excluded).

[135] Project based expenditure excluding real cost escalation and following adjustment for environmental management.

Table 4.20: Components of United Energy's proposed Other repex for next RCP - $m, real 2021

Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Programs						
Replace UE Owned Substation Door	0.2	0.2	0.2	0.2	0.2	1.2
Replace Dist. Line Capacitor Can	0.1	0.1	0.1	0.1	0.1	0.3
Pole reinforcement - PL	0.0	0.0	0.0	0.0	0.0	0.1
Zone Substation HV insulator replacement 11kV and 22kV	0.0	0.0	0.0	0.0	0.0	0.1
Projects						
Control room/building replacement (5 sites)	0.4	0.6	0.6	0.4	0.0	2.1
Building works	0.2	0.2	0.2	0.2	0.2	0.8
ZSS earth grid repairs annual program	0.2	0.2	0.2	0.1	0.1	0.7
OR #1 Cap Bank replacement	0.0	0.1	0.3	0.1	0.0	0.6
Distribution building replacement	0.1	0.1	0.1	0.1	0.1	0.5
OE building extension	0.0	0.0	0.0	0.1	0.3	0.4
ZSS cap bank capacitor replacement	0.1	0.1	0.1	0.1	0.1	0.3
SR new switch room	0.2	0.0	0.0	0.0	0.0	0.2
Steel replacement	0.0	0.0	0.0	0.0	0.0	0.0
Environmental Related Repex	0.2	0.2	0.2	0.2	0.2	1.0
Allocated projects						
Transformer Replacement (16 sites)	0.4	0.4	0.5	0.5	0.5	2.2
Switchyard Replacement (3 sites)	0.0	0.3	0.5	0.3	0.0	1.1
SH 6.6kV conversion	0.0	0.1	0.1	0.0	0.0	0.3
STO station risk management	0.0	0.0	0.0	0.0	0.0	0.0
Total	**2.0**	**2.5**	**3.0**	**2.5**	**1.7**	**11.9**

Source: EMCa analysis of IR034 and UE MOD 4.03 mapping reconciliation. Excludes real cost escalation

436. United Energy has provided the following documentation with its submission to support its expenditure:

- Unitised volume model (UE MOD 4.02) - which forecasts replacement volumes based on historical replacement volumes for low-cost, high-volume asset interventions which include components of other repex; and
- Expenditure model - comprising its Plant, stations and lines replacement expenditure (UE MOD 4.03).

437. United Energy has not provided a business case or other justification document for the proposed replacement volumes or expenditure. We therefore sought to understand the rationale for the forecast from our review of other supporting information.[136]

136 Including the Regulatory proposal, RIN016 and asset strategy documents

Our assessment

Trend is likely to be a better indicator of expenditure requirements

438. According to United Energy,[137] the expenditure associated with the other repex group[138] is increasing from $8.9m in the current RCP to $10.5m[139] in the next RCP. We were not provided with any supporting documentation for this group of expenditure.

439. The forecast expenditure over the next RCP is similar to historical levels. However, approximately one third of the forecast expenditure is allocated as a part of projects included in other categories such as Transformer replacement. We have assumed that the practice of allocating project expenditure in this way has similarly been applied to the historical expenditure. The balance is dominated by civil works for new building and replacement control rooms.

Some reclassification of expenditure required

440. United Energy has not adequately explained the basis for expenditure that is classified as Pole Reinforcement – PL with material code RRP. Absent better information, we consider that pole reinforcement for Public Lighting (PL) should be classified as ACS and excluded from the assessment of SCS, albeit it is only approximately $0.1m.

Summary of our assessment

441. Given the proposed increase in substation-related expenditure by United Energy, it is not surprising to have similar increases in facilities infrastructure associated with these upgrades. This includes control room and building upgrades as proposed by United Energy.

442. With the exception of the pole reinforcement expenditure for public lighting, which we consider is incorrectly classified, we consider that the forecast expenditure is likely to be reasonable.

4.5 Findings and implications for United Energy'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

443. In our assessment of United Energy's proposed expenditure, we sought to understand the basis for inclusion of the project and program expenditure into the forecast and the rationale for the proposed replacement volumes. We therefore looked for evidence of justification of the proposed expenditure from the information provided, consistent with the normal requirements of a business case-like document, to inform the development of a prudent, efficient and reasonable program of forecast expenditure.

444. 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.

137 United Energy Regulatory Proposal Table 4.11

138 Excluding environment program expenditure

139 The basis for the difference between the total of $10.5m included here for reference and the $11.9m included in the forecast expenditure of the other repex category is not provided, although $1.0m difference results from the amended environmental expenditures.

445. 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. Specifically, we sought to understand how United Energy has taken into account to the requirements of the NER and expenditure assessment guidelines, consistent with our scope of work.

446. Where a project is proposed to support meeting United Energy's AFAP obligations, we would expect to see a cost-benefit analysis (or similar) to confirm that the proposed expenditure is required to meet its AFAP obligations. In most cases, we did not see evidence of how United Energy had satisfied itself that the proposed expenditure met the requirements of the NER.

Some proposed projects and programs may duplicate work already in the 'base' repex, and do not appear to have been considered within the prioritisation and optimisation processes of the governance and management framework

447. United Energy has described application of an iterative top-down challenge process to their capex forecasts (as described in section 3). We understand that certain projects were excluded from the proposal as a part of the Executive review process. However, we also see evidence that projects and programs have been included in the forecast without evidence of prioritisation or portfolio optimisation, especially given the existence of similar programs of an ongoing nature.

448. 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 might be reasonably deferred.

449. A large proportion of the expenditure is based on its unitised volume model and which, with the exception of poles and a number of individual line items, is based on an average of historical volumes that is likely to be a reasonable reflection of forecast replacement volumes. In cases where United Energy has proposed additional targeted replacement projects, and which are largely above the historical trend, the relationship to its existing replacement programs has not been established. Further, there is insufficient evidence to demonstrate how the projects and programs have been optimised to achieve the most efficient outcomes for consumers.

Full impact of delivered cost efficiencies not evident

450. In terms of cost efficiency, we are not convinced that the cost efficiencies identified by United Energy, and which have been realised during the current RCP, are adequately reflected in the unit costs relied upon by United Energy 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 are likely higher than would be reflective of an efficient level.

4.5.2 Implications to forecast expenditure

451. Based on the information available to us at the time of preparing this report, we consider that United Energy has not sufficiently demonstrated that its proposed repex forecast is prudent and efficient. We provide a summary of our assessment by RIN group below.

452. On the basis that United Energy has determined that the proposed replacement volume for its **Overhead conductor** and **Underground cable** categories is necessary to meet its safety obligations, we consider that these forecast replacement volumes are reasonable. On balance, due to the relatively low level of expenditure (and excluding the allocations from other RIN categories), the forecast capex for these categories is also likely to be reasonable.

453. For many of the remaining categories, we consider that United Energy has not established a reasonable basis for the extent of the proposed increases in expenditure. We found:

- **Poles:** The incremental program for concrete pole replacement ($3.9m) appears reasonable. However, we do not consider that the forecast expenditure for wood poles is representative of a prudent and efficient level.

- **Pole top structures:** United Energy has not justified an increase to its forecast expenditure for pole-top structures above that which it is currently incurring. Subject to review of its input data assumptions, expenditure may be at a level slightly lower than is proposed using its unitized volume model.
- **Service lines:** United Energy has not adequately demonstrated that the current defect driven program, if prioritised based on highest risk service lines, will be insufficient to meet its expected safety obligations.
- **Transformers:** Given the size and complexity of the proposed replacement program, we would expect to see variations from the proposed plan as the next RCP progresses such that a number of transformer replacement projects are likely to roll-over into the subsequent RCP. Accordingly, we consider that United Energy will incur a level of expenditure on transformer replacement at a level lower than it has proposed.
- **Switchgear:** We consider that the proposed switchboard and switchyard replacements will proceed as planned to manage United Energy's exposure to increasing risk cost and to ensure reliability is maintained. However, when considering the transformer and switchgear program together, we consider that a proportion of the expenditure will likely be deferred due to the complexity of the programs. For the program-based and targeted replacement projects, we found examples of where key components were driving increases to the forecast expenditure. Whilst subsequent corrections were provided by United Energy, the robustness of the forecasting method and review process undertaken by United Energy was called into question. Accordingly, we consider that the extent of proposed increases for these components have not been adequately supported as being prudent and efficient forecast of expenditure.
- **SCADA, network control and protection:** United Energy has not provided sufficient information to support its SCADA, network control and protection expenditure. Similarly, the proposed increase for communications-related projects was not justified by the information provided.

454. The forecast expenditure associated with projects included in the 'other' repex group is likely to be reasonable.

5 REVIEW OF PROPOSED NON-DER AUGEX

In this section, we present our assessment of United Energy's forecast augex expenditure for the next RCP, with the exception of solar enablement expenditure.

We used sensitivity analyses to examine the robustness of the proposed options and the timing of activity to variances in the demand forecast. The results suggest that United Energy's proposed expenditure may be over-estimated,

In each of the 'Focus Projects' that AER asked us to review, we consider that deferral of the project completion date beyond the next RCP is likely to result in more prudent and efficient outcomes.

United Energy has presented insufficient supporting information to justify the quantum of the remaining non-DER expenditure. It has relied on its own planning process and cost estimation methodology as evidence of prudent and efficient capex. We consider that this is not sufficient evidence to support the proposed expenditure.

5.1 Introduction

455. We reviewed the information provided by United Energy to support its proposed augex (non-solar enablement) forecast, including the business cases and relevant supporting information provided. Our focus is to assess the extent to which the forecast expenditure is likely to meet the NER criteria.

456. The AER identified a number of 'Focus' projects, which we have included explicitly in our assessment of the proposed augex forecast within the relevant category of expenditure, as denoted below:

- Doncaster supply area;
- Malvern supply area;
- Keysborough supply area; and
- Mornington supply area.

457. United Energy's solar enablement project is also an augex project and a focus project (as designated by the AER for our review). We refer to it for completeness in the overview of the augex expenditure in the next section. However, our assessment of it is presented in section 6.

5.2 Summary of United Energy's proposed augex

5.2.1 Overview

458. United Energy has proposed $182.0m for total augex for the next RCP, at an average annual expenditure of $36.4m. In the table below, we show augex by RIN Category, including real cost escalation.

Table 5.1: United Energy's proposed Augex for the next RCP - $m, real 2021

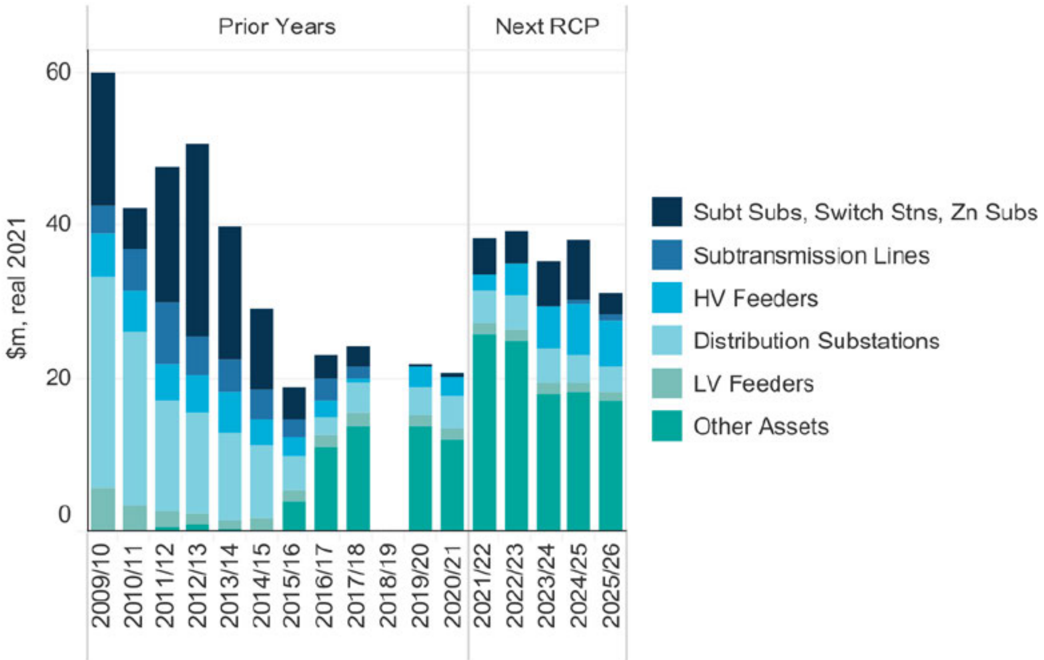
Group	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Subtransmission Substations, Switching Stations, Zone Substations	4.7	4.3	5.8	7.7	3.0	25.5
Subtransmission Lines	0.0	0.0	0.0	0.5	0.7	1.2
HV Feeders	2.3	4.1	5.8	6.7	6.0	24.8
Distribution Substations	4.2	4.4	4.4	3.7	3.3	19.9
LV Feeders	1.4	1.5	1.5	1.2	1.1	6.7
Other Assets	25.7	25.0	17.9	18.1	17.1	103.8
Total	**38.3**	**39.2**	**35.3**	**38.0**	**31.2**	**182.0**

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

5.2.2 Augex trend

459. 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 5.1: United Energy's augex expenditure by asset category - $m, real 2021



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

5.2.3 Observations from the augex trend

460. The augex forecast by United Energy for the next RCP is considerably and consistently higher than in the current RCP, with the uplift in capex driven by the Other assets, HV feeders, and the solar enablement programs.

5.2.4 Augex capex categorised by function

461. The table below shows grouping of projects by functional type and also the AER Focus projects referred to above. Our assessment is structured according to these functional types.

Table 5.2: United Energy augex for the next RCP by Function Type and showing AER Focus projects and additional business cases reviewed - $m, real 2021[140]

Group / Focus & BC	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Subtransmission Substations, Switching Stations, Zone Substations	**4.6**	**4.2**	**5.6**	**7.3**	**2.8**	**24.6**
AER Focus	4.4	4.1	5.2	6.9	2.3	22.9
Doncaster SA			*4.3*	*2.1*		*6.4*
EM SA		*1.9*	*0.9*			*2.8*
KBH SA	*4.4*	*2.2*				*6.6*
MTN SA				*4.7*	*2.3*	*7.1*
Remainder	0.2	0.1	0.4	0.5	0.5	1.7
Subtransmission Lines				**0.5**	**0.7**	**1.2**
HV Feeders	**2.3**	**4.0**	**5.5**	**6.4**	**5.6**	**23.7**
AER Focus	0.5	2.3	2.3			5.1
EM SA		*2.3*	*2.3*			*4.7*
MTN SA	*0.5*					*0.5*
Additional BC	4.3	2.4	1.3	2.1	0.8	11.0
HV Feeders	*4.3*	*2.4*	*1.3*	*2.1*	*0.8*	*11.0*
Remainder	-2.5	-0.8	1.9	4.2	4.8	7.6
Distribution Substations	**4.1**	**4.3**	**4.2**	**3.5**	**3.1**	**19.2**
Additional BC	4.4	4.4	4.4	4.4	4.4	22.0
DSS P1	*1.9*	*1.6*	*0.9*	*0.9*	*0.5*	*5.8*
DSS P2	*0.9*	*0.9*	*1.4*	*1.0*	*1.4*	*5.7*
DSS P3	*0.8*	*1.1*	*1.3*	*1.7*	*1.7*	*6.6*
Pole TX Upgr 200-500kVA	*0.8*	*0.8*	*0.8*	*0.8*	*0.8*	*4.0*
Remainder	-0.3	-0.1	-0.2	-0.9	-1.3	-2.8
LV Feeders	**1.4**	**1.5**	**1.4**	**1.2**	**1.0**	**6.5**
Additional BC	1.5	1.5	1.5	1.5	1.5	7.4
DSS P1	*0.6*	*0.5*	*0.3*	*0.3*	*0.2*	*1.9*
DSS P2	*0.3*	*0.3*	*0.5*	*0.3*	*0.5*	*1.9*
DSS P3	*0.3*	*0.4*	*0.4*	*0.6*	*0.6*	*2.2*
Pole TX Upgr 200-500kVA	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*1.3*
Remainder	-0.1	0.0	-0.1	-0.3	-0.4	-0.9
Other Assets	**25.6**	**24.1**	**17.0**	**17.0**	**15.4**	**99.1**
AER Focus	7.5	9.6	8.7	9.2	7.5	42.4
Solar Enablement	*7.5*	*9.6*	*8.7*	*9.2*	*7.5*	*42.4*
Additional BC	6.8	6.6	2.0	2.0	2.0	19.3
3G	*3.0*	*3.0*				*6.0*
5 Minute Settlement	*0.9*	*0.6*	*0.6*	*0.6*	*0.7*	*3.4*
Digital network	*1.4*	*1.4*	*1.4*	*1.4*	*1.4*	*6.8*
Keys	*1.6*	*1.6*				*3.1*
Remainder	11.4	8.0	6.4	5.8	5.9	37.4
Total	**38.0**	**38.0**	**33.8**	**35.8**	**28.7**	**174.3**

Source: EMCa analysis of United Energy MOD 6.01. excludes real cost escalation

140 Solar Enablement is reviewed in section 6

5.3 United Energy's augex forecasting methods

Augex activity forecasting process

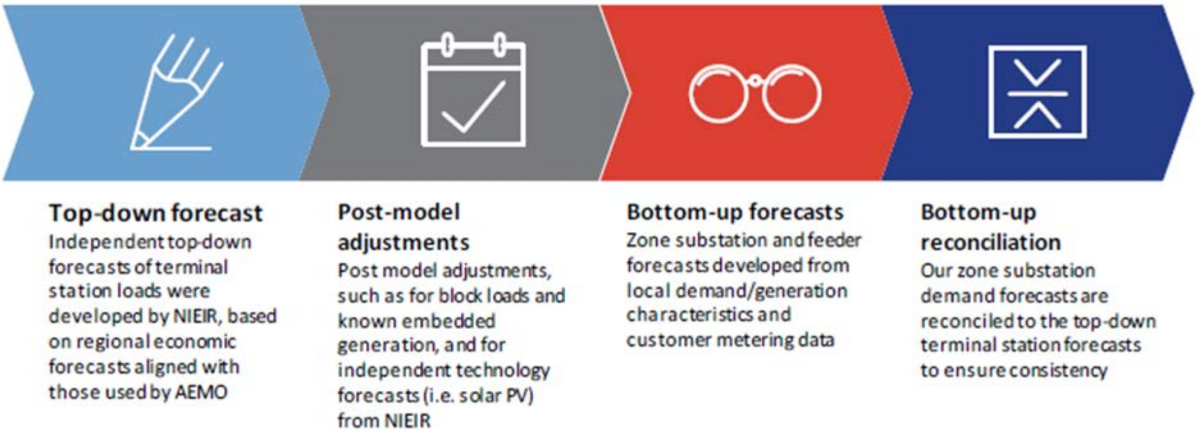
462. United Energy's augex investment includes both demand-driven and non-demand driven projects.

Demand-driven augmentation

463. Based on forecast demand, United Energy determines where the capacity of its network is expected to be exceeded and identifies the appropriate intervention. The interventions include reconfiguring the network, investing in additional infrastructure, or implementing non-network solutions.

464. The figure below summarises United Energy's demand forecasting approach.

Figure 5.2: United Energy's demand forecasting approach



Source: United Energy Regulatory Proposal, Figure 6.7. p105

465. United Energy 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. United Energy 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.'*[141]

Non-demand driven augmentation[142]

466. United Energy has also 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.

Non-network solutions[143]

467. United Energy 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. United Energy's 'Summer Saver' residential behavioural demand response program provides'... *demand response at constrained distribution substations and*

141 United Energy Regulatory Proposal, page 107

142 United Energy Regulatory Proposal, page 106

143 United Energy Regulatory Proposal, pages 107-108

LV circuits…and is now part of our business as usual approach to demand response (in lieu of capital investment).'

Cost forecasts[144]

468. United Energy states that it has 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.'

469. United Energy adjusts costs for forecast growth in real input prices over time, such as labour, materials, and contracted services.

5.3.2 Assessment of United Energy's augex forecasting methods

United Energy's top-down/bottom-up demand forecast reconciliation approach is consistent with industry practice

470. At a high level, United Energy's demand forecasting methodology, shown in Figure 5.2, is consistent with industry practice in that it includes a reconciliation between its top-down forecast at the terminal station level, prepared for it by the Centre of International Economics (CIE) and United Energy'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.

471. United Energy advises that it has used the most recent complete data that is presently available, which is from the 2017/18 year. This data is now approximately two years old. United Energy has stated that it will update its forecasts with more recent data for its revised regulatory proposal, but for now, we acknowledge that the demand forecasts are based on the information available.

472. 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 (i.e., 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.

473. 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(s) and to the timing of the proposed work to negative variances to the input assumptions, as we discuss below.

Energy at risk is hard-coded into the model

474. United Energy has calculated the energy at risk outside of the probabilistic planning model that was provided with United Energy's regulatory proposal. United Energy provided its energy at risk calculations in response to an Information Request (IR011). Based on the approach to deriving the energy at risk described in the 2019 DAPR and as applied in the models, we are satisfied that the methodology is reasonable.[145]

144 United Energy Regulatory Proposal, page 108

145 United Energy Distribution Annual Planning Report, section 6

The value of expected unserved energy is hard-coded in the model but can be varied by weighting of the forecast peak demand PoE

475. United Energy's probabilistic planning model uses a probability weighted blend of the 10% PoE peak demand forecast and the 50% PoE[146] peak demand forecast. This is used to vary the expected value of unserved energy by scaling the expected unserved energy at 10% PoE and at 50% PoE. The weighting is 30% of the 10% PoE demand forecast to 70% of the 50% PoE demand forecast. Our assessment of this approach is discussed in section 3.

476. 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, the realistic timing of the option (i.e., completed within the next RCP or deferred), and the sensitivity of the proposed options to negative variances in the demand forecast.

Value of VCR is weighted may be overstated in some cases

477. The value that United Energy has used for VCR is the Victorian average, which is based on the AEMO 2014 report, escalated to current terms. This value is used in the calculation of the cost of unserved energy. As we discuss in our assessments of each of the Focus Projects, we consider that the Victorian average VCR is likely to be materially higher than a VCR determined as weighted average based on the proportion of total energy consumed by each customer segment at the substation(s) in question.

United Energy's probabilistic planning models limit sensitivity analyses

478. United Energy 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 probability of exceedance between the 50% PoE and the 10% PoE, the discount rate, the demand management cost/MW, and the VCR.

479. 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 (MWh) are hard coded into the energy at risk calculation.

480. We have focused on the sensitivity of the planned work to negative variances of key inputs to United Energy's probabilistic planning to take into account demand and energy forecasting uncertainty because:

- Negative variances may defer expenditure out of the next RCP, whereas positive variances are likely to bring capex forward and still be 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 – but the impact is uncertain even 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.

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[146] 50th percentile demand forecast or 50 per cent probability of exceedance (PoE). It 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

5.4 Subtransmission Substations, Switching Stations, Zone Substations

5.4.1 Introduction

481. In this section, we assess four AER focus projects: Doncaster supply area ($6.4m), Malvern supply area ($7.5m), Keysborough supply area ($6.6m), and Mornington supply area ($7.6m). We discuss the total scope of each of the focus projects in this section, noting that $4.7m of the Malvern supply area capex and $0.5m of the Mornington supply area capex is allocated to the HV feeders RIN category.

482. The remainder of the forecast capex comprises $1.7m for installation of nine automatic load shedding schemes.

5.4.2 Doncaster area strategy

Overview of project

483. The Doncaster supply area supplies around 30,500 customers via Doncaster (DC) substation. Customers are predominantly residential, with a mix of small to large commercial establishments.[147]

484. DC substation was established in the 1960s and has 1 x 27MVA and 2 x 30MVA 66/22kV transformers and 10 distribution feeders. DC substation is connected to the Templestowe Terminal Station (TSTS) through a radial subtransmission system. There are no 66kV line circuit breakers, so a 66kV line fault will trip a DC 66kV bus circuit breaker and trip one of the three DC transformer circuits.

485. United Energy is addressing two issues in the Doncaster supply area with its proposed project: (i) a DC substation firm capacity shortfall; and (ii) high 22kV distribution feeder utilisation.

486. United Energy proposes to install a fourth DC substation transformer with two new feeders before December 2024 at a forecast capital cost of $6.4m. This is the second stage of a two-stage project which commenced with establishing a new feeder from Box Hill (BH) substation and reconfiguring the distribution network. The first stage is scheduled to be completed in 2020/21 (i.e., in the current RCP).

Our assessment

487. With the exception of section 5 of the business case (Recommendation), which includes an updated timing assessment for stage 2 only (i.e., following completion of the stage 1 BH feeder), the business case and the supporting model have been derived with stage 1 of the project included as part of the options analysis. As noted above, the new feeder between DC and BH substations is scheduled to be commissioned within the next few months.

488. We first reviewed the business case and model as presented and then updated our findings based on the timing adjustment from the revised information in section 5 of the business case.

There is sufficient evidence for taking action at DC substation within the next 10 years

489. United Energy's 10% PoE demand forecast for DC substation is shown in the figure below. Growth in peak demand is forecast to be 1.3% over the next 7-10 years. Figure 5.3 is from United Energy's business case and shows that the peak demand is well above the N-1 cyclic rating[148] (or 'N-1 capacity') and is trending towards the N cyclic rating.[149] United

147 United Energy BUS 6.02 - DC supply area, page 5

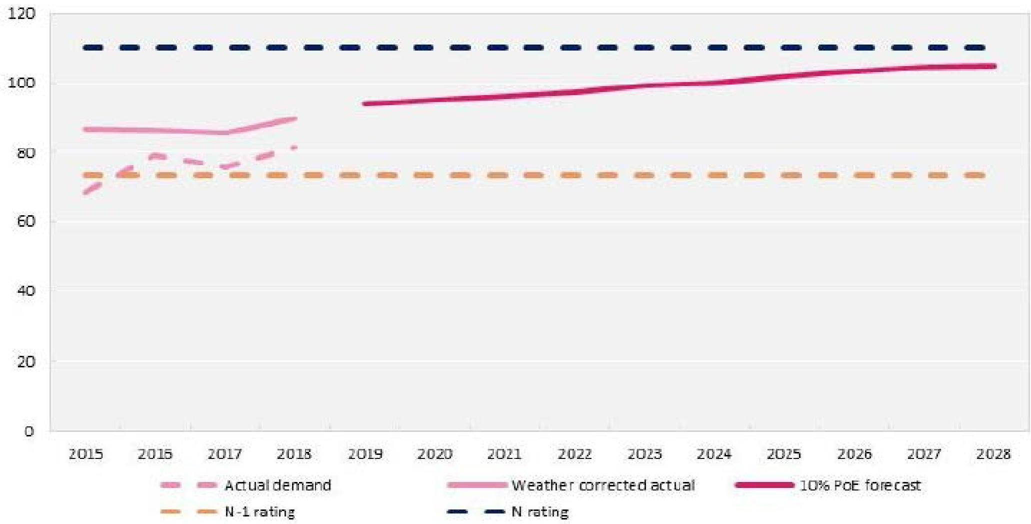
148 If demand exceeds the N-1 cyclic rating (which is typically determined with one transformer at the substation out-of-service) customer load shedding may be required

149 The capacity of the substation based on the cyclic rating of the installed transformers

Energy has provided information about multi-story developments in the Box Hill central area to support the demand forecast.

490. After load transfer to contiguous zone substations is accounted for, a capacity shortfall of approximately 20MVA is forecast for 2028, equating to about 8,000 customers.[150] The load transfer capacity is forecast by United Energy to decline over time from the current level of 15MVA to 11.4MVA by 2028.[151] This assumption appears to be reasonable.

Figure 5.3: DC substation maximum demand forecast (10% PoE, MW) prior to stage 1 feeder implementation



Source: United Energy, BUS 6.04, Figure 2

491. Furthermore, as United Energy explains:[152]

- The transformers at DC substation are over 50 years old and two of them are in poor condition and have been assessed as being very close to end-of-life; and
- Both transformers in poor condition are of the same make and age and have the same design characteristics which increases common-mode failure risk.

492. United Energy has not presented the health index (HI) for the transformers or information about the forecast HI deterioration over time.

493. The figure below shows the forecast feeder utilisation at DC substation corresponding to the 10%PoE demand forecast. Feeder DC06 is expected to exceed 100% utilisation in 2021. DC04 and DC05 feeders are expected to exceed 100% utilisation in 2025. United Energy states that high feeder utilisation '*limits the ability to manage supply during both system normal conditions and during emergencies (i.e., loss of a feeder due to unplanned faults) is further limited by the high utilisation of neighbouring feeders.'*[153]

494. From the load duration curve presented as Figure 6 in the business case, DC substation has a low load factor with approximately 30% of the peak demand hours experienced just 2% (i.e., 175 hrs) of the hours in a year. This is typical of predominantly residential substations.

495. This means that at peak times, the high utilisation of a large number of feeders could lead to operational problems, but the amount of time that the feeders exceed 90% loading could be much less than 1% of the year.

496. Had United Energy presented the feeder utilisation forecast based on the 50% PoE demand, which by definition is the median of the outcomes, the graph may have shown that

150 United Energy BUS 6.02 page 10

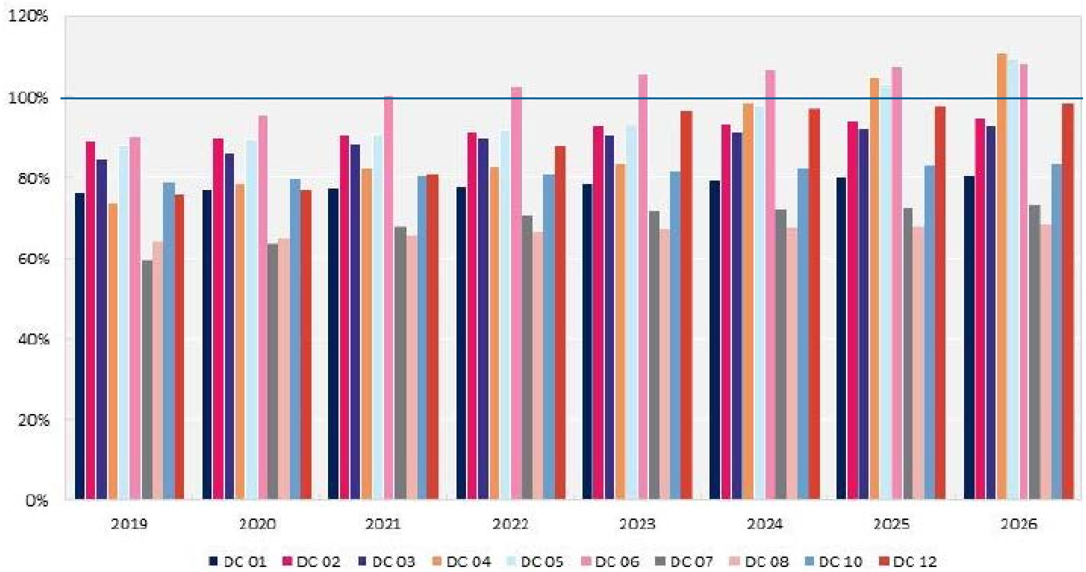
151 United Energy MOD 6.04 – DC supply area

152 United Energy, UE BUS 6.02 – DC supply area, page 9

153 United Energy, UE BUS 6.02 – DC supply area, page 9

feeder utilisations may not exceed 100% by the end of the next RCP (or if they do, it would be by a small amount and for relatively short periods of time).

Figure 5.4: DC substation feeder utilisation forecast prior to Stage 1 feeder implementation (10% PoE forecast)



Source: United Energy, BUS 6.05, Figure 4

United Energy's VCR for the economic analysis appears to be too high

497. United Energy has applied a weighted average $42,760 VCR in its model. This is the Victorian average VCR. Given United Energy's statement that the Doncaster supply area customers '… *are predominantly residential, with a mix of small to large commercial establishments'* we consider that a VCR value based on weighted actual demand specific to these customer segments would be more appropriate.[154]

498. In the absence of any other detail on customer segment demand from United Energy, and cognisant that an individual commercial customer will demand more energy than an individual residential customer, we consider that a weighted VCR based on a 60%:40% residential:commercial PoE weighting[155] is a more reasonable base input assumption. This alternative assumption results in a weighted average VCR for DC substation of $35,444/MWh.

499. The result of applying this input assumption is discussed below.

United Energy's selected Option 1 is unlikely to be the prudent approach for the next RCP

500. United Energy considered six options in addition to 'Do nothing', as shown in the table below. The net economic benefit is measured against the Option 0 counterfactual.

154 Noting that Powercor and CitiPower base its analysis on actual weighted average demand

155 Residential VCR = $26,800/MWh and Commercial VCR = $48,410/MWh

Table 5.3: Summary of United Energy's DC substation options analysis - $m, real 2019

Option	NPV net benefit
0. Do nothing / maintain the status quo	0
1. New BH feeder, followed by a fourth transformer and additional two feeders at DC substation	14.2
2. Fourth transformer and three new feeders at DC substation	14.0
3. New BH feeder, followed by transformer replacement and feeder works at DC	13.8
4. New BH feeder, followed by non-network solution to defer preferred network option	14.1
5. New TSE zone substation	N/A
6. Power factor correction	N/A

Source: United Energy UE BUS 6.02, Table 2, UE MOD 6.04
Note: n/a means not available from United Energy's analysis; TSE substation is Templestowe

501. Option 0 is should have been considered more robustly by United Energy than merely as a counterfactual; however, it is unlikely to be the technically and economically prudent solution given the loading level and condition of the transformers. United Energy dismissed Option 5 on the basis of its comparatively high capital cost. Option 6 was not considered credible because United Energy advised that the power factor is already close to unity.

502. Option 2 is similar to Option 1 and, primarily because it calls for a larger up-front investment compared to the other options, it is unlikely to be the prudent selection compared to Option 1.

503. Option 3 has a lower capital cost than the other credible options and a slightly lower NPV so on that basis is a strong contender as the prudent option. However as United Energy points out: '*it does not address the capacity constraint at DC (as the N-1 rating at the station is not increased) and subsequently a fourth transformer and switchboard will still be required in 2033. Moreover, as there are no spare circuit breakers at DC, the new DC feeder will need to be connected using a jumbo connection.*'[156] A more robust economic analysis would lead to a significantly reduced NPV given the low discount rate. We therefore consider that Option 3 is inferior to Option 1.

504. Option 4 is based on $87,000/MW for NNS, which we consider to be a reasonable assumption based on the evidence provided.[157] The table below shows United Energy's estimate of the amount of NNS required to '*…bring the station load at risk back to the previous year's level and defer by one year the need for the balance of the option…*'[158]

Table 5.4: United Energy's estimated DC substation Non-Network Support requirement (MW)

	2023	2024	2025	2026	2027
Peak demand at risk after load transfer	17.7	18.8	20.7	22.4	23.9
Non network support required	0.0	0.0	1.9	3.6	5.1

Source: United Energy UE BUS 6.02, Table 6, page 16

505. United Energy dismissed Option 4 despite promoting the considerable success of its Summer Saver Program (SSP) as a means of deferring network capital.[159] However, we consider it is likely that application of NNS becomes practically and economically

156 United Energy UE BUS 6,02 – DC supply area, page 15

157 United Energy, Attachment UE ATT102 - CulterMerz - Review of demand management - Feb2019 - Public, CutlerMerz, Review of demand management unit rates

158 United Energy UE BUS 6,02 – DC supply area, page 15

159 United Energy, Regulatory Proposal 2021-26, pages 16, 18, 46, 89, 102-103, 108, etc

challenging beyond the next RCP with escalating risk of transformer failure and increasing feeder utilisation.

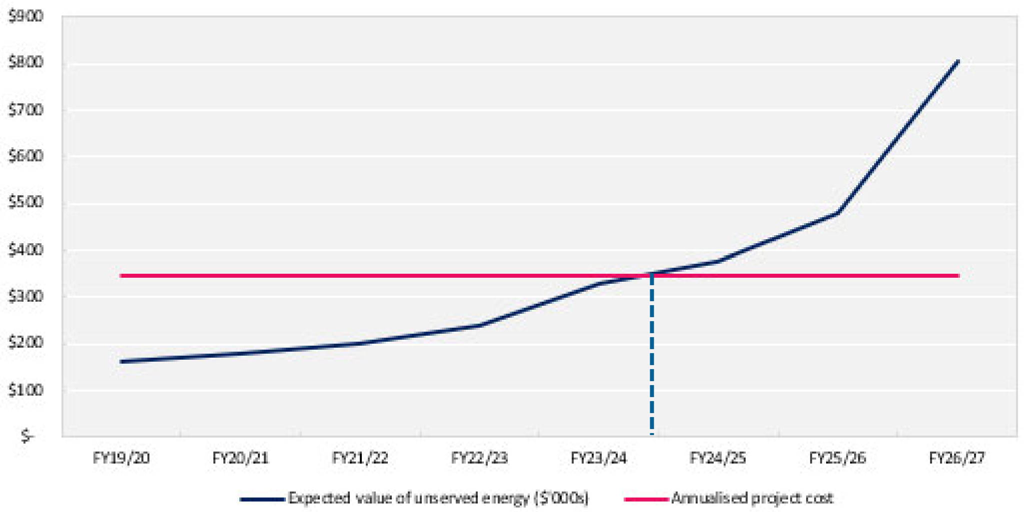
506. Option 1 is preferred by United Energy and includes completing the stage 1 feeder to allow transfer of load off feeder DC06.

507. Based on our review of United Energy's analysis, we consider that Option 1 is superior to Options 0, 2, 3, and 6. We are unaware of how United Energy's longer term plan for the area might evolve beyond the next RCP and the economic analysis does not attempt to look much further than 2027/28. Therefore, we are not in a position to confirm that installing a fourth transformer at DC substation is a better approach than a new Templestowe (TSE) substation (Option 5).

The economically optimum timing for stage 2 may be beyond the next RCP

508. The economically optimum timing[160] for Option 1 is 2024/25 using United Energy's weighted demand forecast, load transfer, and VCR assumptions, as shown in the figure below.

Figure 5.5: United Energy's assessment of energy not served vs annualised cost of Option 1 - $k, real 2019



Source: United Energy, UE MOD 6.04

509. United Energy undertook a sensitivity analysis under 'best' and 'worst' case scenarios and concluded that Option 1 was still the preferred solution. However, it did not consider the sensitivity of the timing of the proposed work under these scenarios.

510. We therefore undertook our own sensitivity analysis, using United Energy's model with:

- Our substituted VCR value, as discussed earlier;
- 100% weighting to the 50% PoE demand forecast (giving a lower expected unserved energy) as a proxy for a lower demand growth rate (but with United Energy's VCR value);
- Our substituted VCR value plus 100% weighting to the 50% PoE demand forecast.

511. We also updated the model with the actual weather-corrected peak demand from 2019 and 2020 as provided by United Energy.[161] Applying the revised VCR value defers the project by one year to 2025/26. Applying only the alternative demand forecast weighting defers the project by two years to 2026/27. The result of applying the two 'EMCa' inputs assumptions is shown in the figure below - the economic timing of stage 2 is deferred to 2027/28 (i.e., by three years). Although we have reservations about the NPV calculations (as discussed above), it is likely that Option 1 retains its slight NPV advantage over the other options with

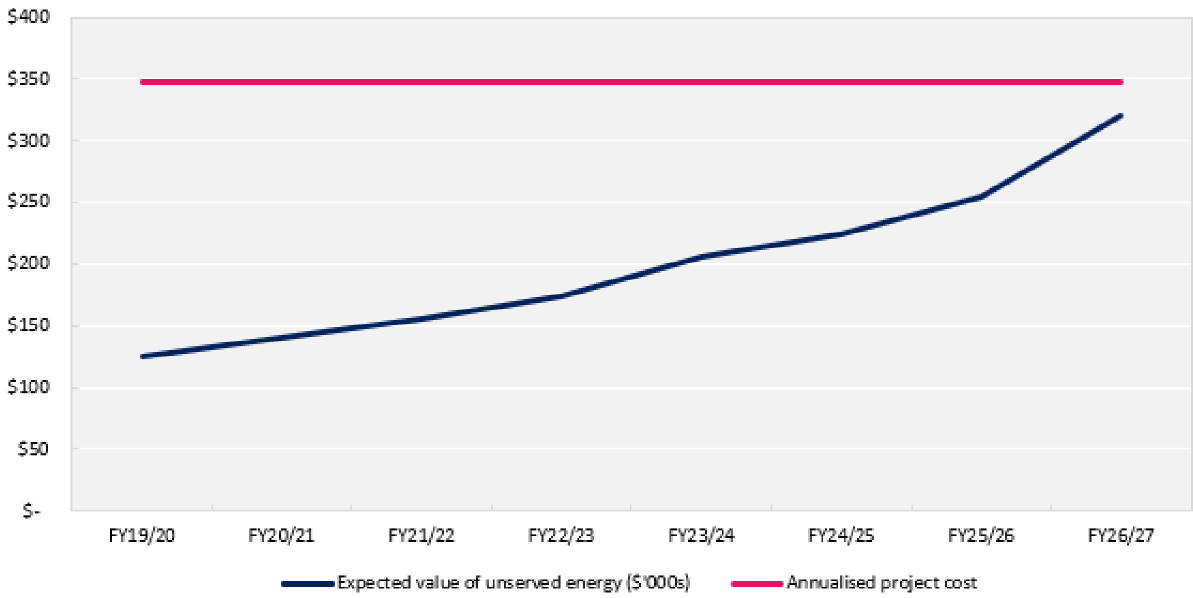
160 The point at which the annual value of unexpected unserved energy exceeds the levelised (or annualised) cost of the solution to 'avoid' the risk cost is the economically optimum timing'

161 United Energy response to AER information request IR021

the revised input assumptions. In our view, deferring the Option 1 capex to the next RCP is more likely to reflect an economically optimum outcome because:

- As discussed in section 3, we consider that the 50% PoE is likely to be more representative of peak demand growth; and
- The near-term issues with the most utilised feeder, DC06, are addressed by proceeding with the stage 1 BH feeder in 2020/21 as planned by United Energy. We assume that absent information to the contrary in the business case, load can subsequently be redistributed on feeders DC04 and DC05 to reduce utilisation, if required.

Figure 5.6: EMCa sensitivity study - energy not served vs annualised cost of Option 1 - $k, real 2019



Source: United Energy, UE MOD 6.04 with EMCa revised inputs: VCR = $35, 444; 100% weighting to 50%PoE

Updated analysis post-stage 1 installation does not change our finding

512. In the recommendation section of the business case, United Energy presents an updated expected unserved energy vs annualised project cost after the installation of the BH feeder. The expected unserved energy curve is flatter after transfer of load to BH substation and the economically optimum timing for stage 2 is deferred (using United Energy's input assumptions), but still indicates that the project should be completed in the next RCP.

513. Based on United Energy's updated analysis, but with what we consider to be more reasonable input assumptions, the economic timing for stage 2 would still be between beyond the end of the next RCP.

The cost estimate is likely to be reasonable

514. United Energy has provided a detailed cost breakdown for the scope of work[162] and has also provided schematics of the substation and feeder augmentations (refer to Appendix B of the business case).

515. We understand that United Energy has recent experience in designing, costing, and delivering substation brownfields work and HV feeder projects, and it should therefore have reasonable building-block information for this project.

516. On this basis we consider that it is likely that the cost estimate is set at a reasonable level.

[162] UE RIN001 - Workbook 1 - Forecast templates - Jan2020 - Public, template 2.3(a)

Summary

517. We consider that United Energy has presented information which indicates that taking action is required within the next decade to address the issues arising from the condition of the assets, the subtransmission configuration, the forecast peak demand growth, and the energy-at-risk DC substation

518. United Energy's probabilistic risk-cost model accounts for the increasing risk cost of 'doing nothing' over the next decade arising from the combination of increasing load and deteriorating condition/increasing PoF for the three installed transformers.

519. We are satisfied that the proposed stage 1 (BH feeder) is required, and we understand that this is currently scheduled to be completed within the current RCP. Stage 1 will offload demand from DC substation, but not to the point where there is no energy at risk over the next RCP.

520. Using United Energy's model, we have analysed the sensitivity of the option selection and timing to two key input assumptions: the assumed VCR and the demand forecast weighting. We applied (i) a VCR that we consider is likely to better reflect the actual characteristics of the supply area, rather than the Victorian average VCR which United Energy has assumed, and (ii) 100% weighting to the 50% PoE demand forecast.

521. The results suggest that further capex at DC substation may be able to be prudently deferred beyond the next RCP.

5.4.3 Malvern supply area strategy

Overview of project

522. The Malvern supply area supplies around 40,000 customers via East Malvern (EM) substation, Caufield (CFD) substation, and Gardiner (K) substation. Customers are predominantly residential, with a mix of small to large commercial establishments.[163]

523. CFD zone substation was built in 2007 and has two 20/33MVA 66/11kV transformers. EM zone substation was built in the 1960s and has two 20/27MVA 66/11kV transformers. Neither EM nor K substations have 66kV line circuit breakers, so faults on the incoming 66kV lines will trip an EM substation transformer or K substation transformer. There are no spare 11kV circuit breakers to establish new feeders at any of the three substations.

524. The N-1 capacity at all three substations is forecast to be exceeded throughout the next RCP '…and several feeders in the area are heavily utilised and/or forecast to be overloaded within the next five years.'

525. United Energy proposes to:

- Install a new 11kV switchboard at EM substation; and
- Establish three new feeders at EM substation and reconfigure the existing network.

526. United Energy refers to this as Option 1 and the forecast capital cost is $7.5m in the next RCP.

Our assessment

There is sufficient evidence for taking action at EM substation within the next 10 years

527. United Energy's 10% PoE forecast for EM substation is shown in the figure below. Growth in maximum demand is forecast to be 1.8% over the next 7-10 years. The forecast peak demand growth at CFD and K substations is 1.3% and 1.7%, respectively.

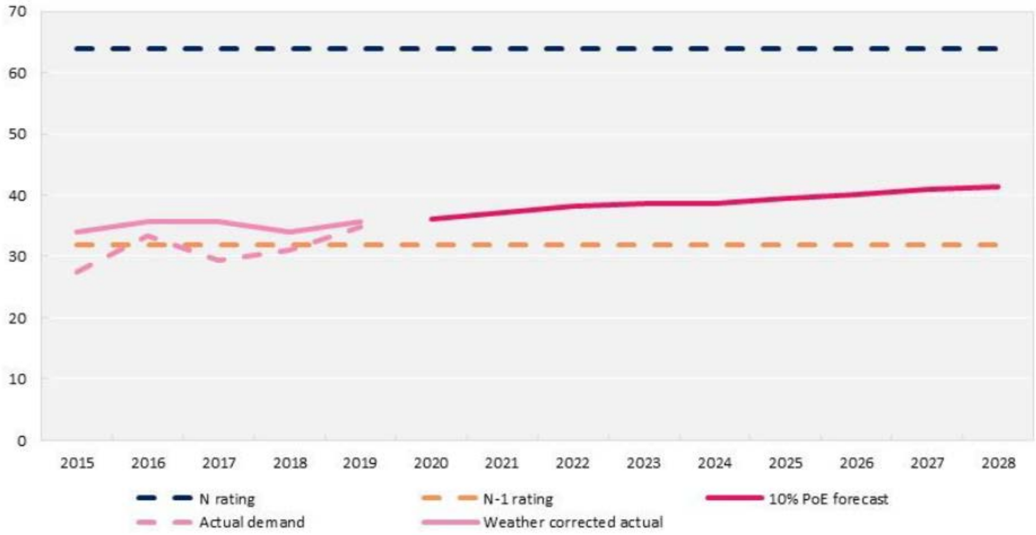
528. Figure 5.7 is from United Energy's business case and shows that the peak demand is above the N-1 cyclic rating[164] (or 'N-1 capacity'). The 10% PoE peak demand at CFD and K

[163] United Energy BUS 6.03 Malvern supply area, page 5

[164] If demand exceeds the N-1 cyclic rating (which is typically determined with one transformer at the substation out-of-service) customer load shedding may be required

substations is higher than at EM substation.[165] United Energy has provided information about developments in the Malvern supply area to support the demand forecast.

Figure 5.7: Malvern substation maximum demand forecast (10% PoE, MW)



Source: United Energy BUS 6.03, Figure 5

529. After load transfers are established, forecast shortfalls in capacity in 2028 following a transformer outage are 9MVA at CFD substation, 5MVA at EM substation, and 10MVA at K substation, respectively. A loss of supply would affect about 10,000 customers.[166] The load transfer capacity is forecast by United Energy to decline over time at each substation. We consider this to be a reasonable assumption.

530. As shown in the figure below, United Energy forecasts that several feeders from CFD, EM and K substations will exceed, or come close to exceeding, their respective utilisation ratings in the next RCP. United Energy states that:

> *'The ability to manage supply during both system-normal conditions and during emergencies (i.e., loss of a feeder due to unplanned faults) is further limited by the high utilisation of neighbouring feeders.'*[167]

531. From the load duration curve presented as Figure 12 in the business case, the three substations have a low load factor with approximately 30% of the peak demand hours experienced in just 2% (175 hrs) of the hours in the year. This is typical of predominantly residential substations. This means that at peak times, the high utilisation of a large number of feeders could lead to operational problems, but the amount of time that the feeders exceed 80% loading could be much less than 2% of the year.

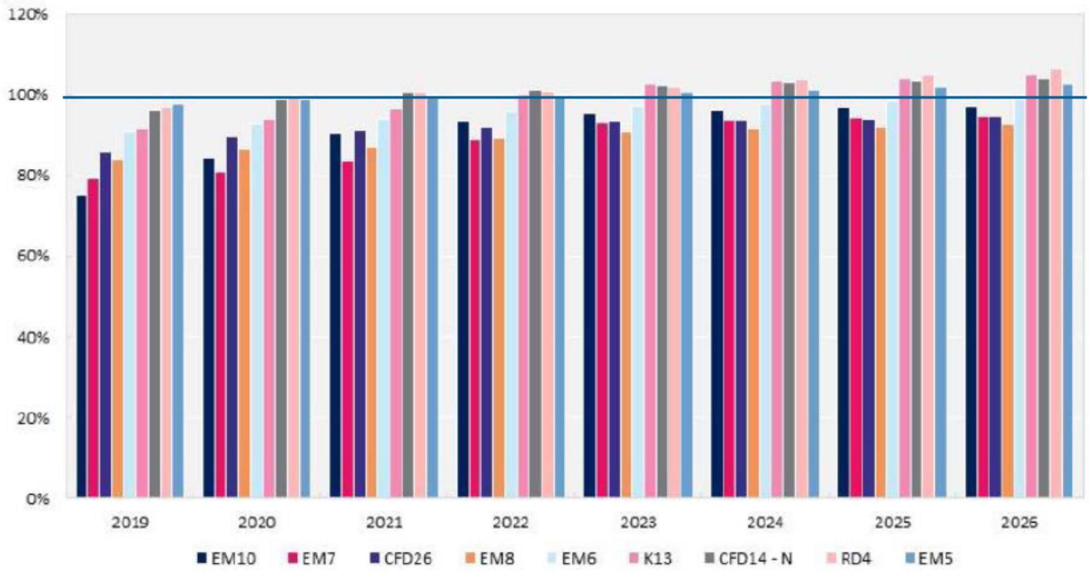
532. If United Energy had presented the feeder utilisation forecast based on the 50% PoE demand, which by definition is the median of the outcomes, the graph may have shown that feeder utilisations may not exceed 100% by the end of the next RCP (or if they do, it would be by a small amount and for relatively short periods of time). Nonetheless, feeder utilisation is high.

165 Refer to figures 4 and 6 in United Energy BUS 6.03 – EM supply area, pages 9-10

166 United Energy BUS 6.03 Malvern supply area, pages 13,14

167 United Energy BUS 6.03 Malvern supply area, pages 13,14

Figure 5.8: Malvern supply area feeder utilisation forecast (10% PoE)



Source: United Energy BUS 6.03, Figure 7

United Energy's VCR for the economic analysis is not reasonable

533. United Energy has again applied a weighted average $42,760 VCR in its model. As with the Doncaster supply area, United Energy states that '*[the] customers are predominantly residential, with a mix of small to large commercial establishments.*'[168] On the same basis as our adjustment for the Doncaster supply area, we consider that a more reasonable weighted average VCR for EM substation is $35,444/MWh.

534. The result of applying this input assumption is discussed below.

United Energy's economic analysis is limited

535. We found the same issues with United Energy's EM model as we described for the Doncaster model. In summary, despite the limitations with the model, we consider that we can still use the model in conjunction with the information in the business case to support our assessment.

Option 1 or Option 4 is likely to be the prudent approach (but with delayed timing)

536. United Energy considered six options in addition to 'Do nothing', as shown in the table below. The net economic benefit is measured against the Option 0 counterfactual.

Table 5.5: Malvern supply area - summary of United Energy's options analysis - $m, real 2019

Option	NPV net Benefit
0. Do nothing / maintain the status quo	n/a
1. Install new switchboard and three new feeders at EM	18.0
2. Install third EM transformer with three new feeders	16.9
3. Install two new feeders at K substation and one new feeder at OR	9.3
4. Non-network solution to defer preferred network option	17.9
5. Power factor correction	n/a

Source: United Energy UE BUS 6.03, Table 2 and UE MOD 6.08
Note: n/a means not available from United Energy's analysis; OR is Ormond substation

168 United Energy BUS 6.03 - EM supply area, page 5

537. Option 0 is unlikely to be the economically prudent solution given the loading level and risk and consequence of transformer and 66kV line outages. United Energy dismissed Option 5 because the power factor is already close to unity.

538. Option 2 has a lower NPV than Option 1 and a higher capital cost. Option 3 has a lower capital cost than Option 1, with a lower NPV, and it requires feeders to cross the Monash Freeway which would give rise to construction and operational risk and is less effective than the feeder routes in Option 1.[169]

539. Option 4 is based on $87,000/MW for NNS, which we consider to be a reasonable assumption based on the evidence provided.[170] The table below shows United Energy's estimate of the amount of NNS required to '*…bring the station load at risk back to the previous year's level and defer by one year the need for the balance of the option…*'[171]

540. The NNS defers Option 1 augmentation by one year.

Table 5.6: United Energy's Malvern substation estimated Non network support requirement (MW)

	2022	2023	2024	2025	2026
Non network support required	0.0	0.0	2.1	2.4	2.7

Source: United Energy BUS 6.03, Table 6, page 19

541. United Energy dismisses this option despite promoting the considerable success of its Summer Saver program as a means of deferring network capital.[172] However, we consider that, if required, 2-3MW of NNS may be a practical and economic option to defer capital investment in network options at one or more of the three substations due to the relatively low peak demand growth forecast.

542. Option 1 includes reconfiguring the distribution network and is United Energy's preferred option. By a small margin, it has the highest NPV and the second lowest capital cost. A new switchboard is required due to the lack of spare feeder circuit breakers at EM substation.

543. EM substation is preferred for augmentation over CFD or K substations because 'EM zone substation is centrally located to the forecast feeder constraints and has less energy at risk than our CFD or K zone substations. The new feeders and network reconfiguration will address the forecast feeder constraints at CFD, EM, K and RD. By permanently offloading both CFD and K, it also reduces the forecast risk at CFD and K zone substations, as well as the two sub-transmission loops…' On the basis of the information provided by United Energy, this appears to be the prudent approach to network augmentation.

544. Based on our review of United Energy's analysis, we consider that Option 1 is superior to Options 0, 2, 3, and 5. However we consider that United Energy should not dismiss the application of NNS as a means of deferring capital investment.

The economically optimum timing is likely to be 2026/27

545. United Energy's probabilistic planning model with its weighted demand forecast, load transfer, and VCR assumptions results in 2024/25 as the economically optimum timing[173] for Option 1, as shown in the figure below. We note that United Energy plans to complete the work in 2023/24.

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169 United Energy, BUS 6.03 – EM supply area, page 19

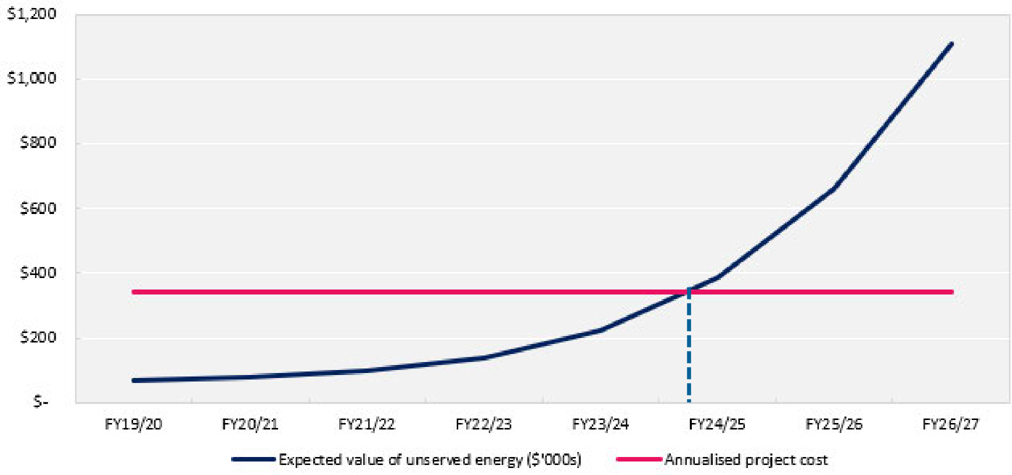
170 United Energy, Attachment UE ATT102 - CulterMerz - Review of demand management - Feb2019 - Public, CutlerMerz, Review of demand management unit rates

171 United Energy BUS 6.03 – EM supply area, page 15

172 United Energy, Regulatory Proposal 2021-26, pages 16, 18, 46, 89, 102-103, 108, etc

173 The point at which the annual value of unexpected unserved energy exceeds the levelised (or annualised) cost of the solution to 'avoid' the risk cost is the economically optimum timing'

Figure 5.9: Malvern supply area - UE's assessment of ENS vs annualised cost of Option 1 - $k, real 2019



Source: United Energy, MOD 6.08

546. United Energy undertook a sensitivity analysis under 'best' and 'worst' case scenarios and concluded that Option 1 was still the preferred solution. It did not consider the sensitivity of the timing of the proposed work under these scenarios.

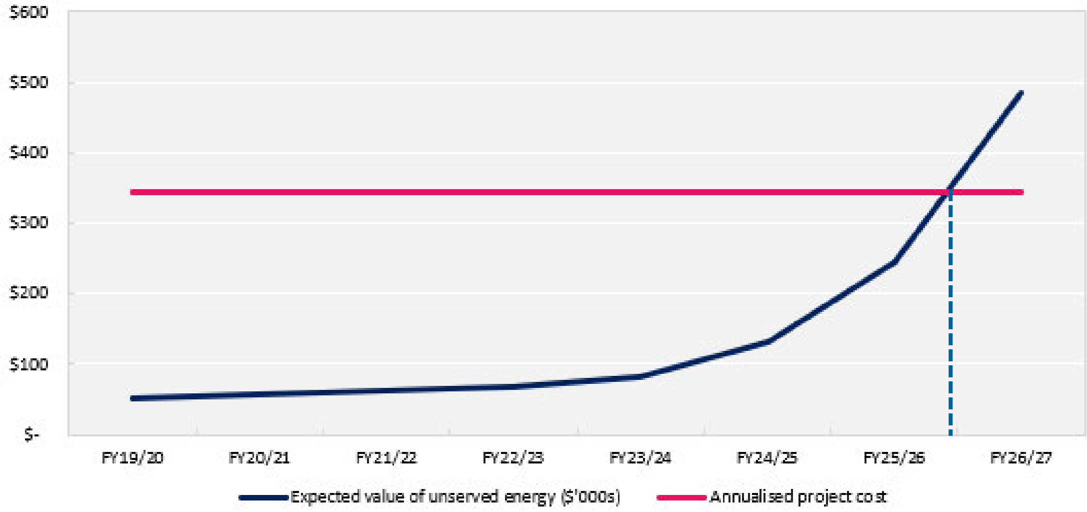
547. We therefore undertook our own sensitivity analysis, using United Energy's model with:

- Our substituted VCR value, as discussed earlier;
- 100% weighting to the 50% PoE demand forecast (giving a lower expected unserved energy) as a proxy for a lower demand growth rate (but with United Energy's VCR value);
- Our substituted VCR value plus 100% weighting to the 50% PoE demand forecast.

548. We also updated the model with the actual weather-corrected peak demand from 2019 and 2020 provided by United Energy.[174] Applying the revised VCR value defers the project by two years to 2026/27. Applying only the alternative demand forecast weighting defers the project by one year to 2025/26. The result of applying the two 'EMCa input assumptions' is shown in the figure below: the economic timing of stage 2 is deferred to 2026/27 (i.e., by two years). This would reduce the capex requirement for the Malvern Supply area to $4.3m (i.e., an adjustment of -$3.2m). Although we have reservations about the NPV calculations (as discussed above), it is likely that Option 1 retains its slight economic advantage over the other options with the revised input assumptions.

[174] United Energy response to AER information request IR021

Figure 5.10: EMCa sensitivity study – energy not served vs annualised cost of Option 1 - $k, real 2019



Source: United Energy MOD 6.06 with EMCa revised inputs: VCR = $35,444; 100% weighting to 50%PoE

Cost estimate is likely to be reasonable

549. United Energy has provided a detailed cost breakdown for the scope of work[175] and schematics of the substation and feeder augmentations (refer to Appendix B of the business case).

550. We understand that United Energy has recent experience in designing, costing, and delivering substations 'brownfield work' and HV feeder projects, and it should therefore have reasonable building-block information for this project.

551. On this basis, we consider it likely that the cost estimate is set at a reasonable level.

Summary

552. We consider that United Energy has presented a case for taking action within the next decade to address the forecast peak demand growth and energy-at-risk in the Malvern supply area.

553. Using United Energy's model, we have analysed the sensitivity of the option selection and timing to two key input assumptions: the assumed VCR and the demand forecast weighting. We applied (i) a VCR that we consider is likely to better reflect the actual characteristics of the supply area, rather than the Victorian average VCR which United Energy has assumed, and (ii) 100% weighting to the 50% PoE demand forecast.

554. The results suggest that completion of the EM substation augmentation project may be able to be prudently deferred beyond the next RCP, perhaps with a relatively small amount of non-network support. We note that United Energy has successfully applied its Summer Saver program in similar circumstances.

5.4.4 Keysborough area strategy

Overview of project

555. Keysborough is one of the fastest growing suburbs in United Energy's network. Keysborough (KBH) substation supplies 9,500 customers.

556. KBH substation is less than six years old. It has a single 66/22kV 20/33MVA transformer and five 22kV feeders, but there are no spare circuit breakers. It is designed to accommodate three transformers and KBH substation can host a relocatable transformer.

557. Peak demand is above the nameplate rating of the transformer but below the N cyclic rating. 'This risk is currently managed through available distribution feeder transfer capacity, and

175 UE RIN001 - Workbook 1 - Forecast templates - Jan2020 - Public, template 2.3(a)

the readiness to host a relocatable transformer in the event of a major transformer outage.'[176] Several KBH substation feeders are forecast to exceed 100% utilisation within the next RCP.

558. To address the risks posed by the increasing load, United Energy propose to:

- install a second transformer at KBH substation; and
- reconfigure the contiguous 22kV distribution network with two new 22kV feeders.

559. United Energy refers to this as Option 1. The forecast capital cost is $6.6m with the project planned to be started in 2021/22 and completed by 2022/23.

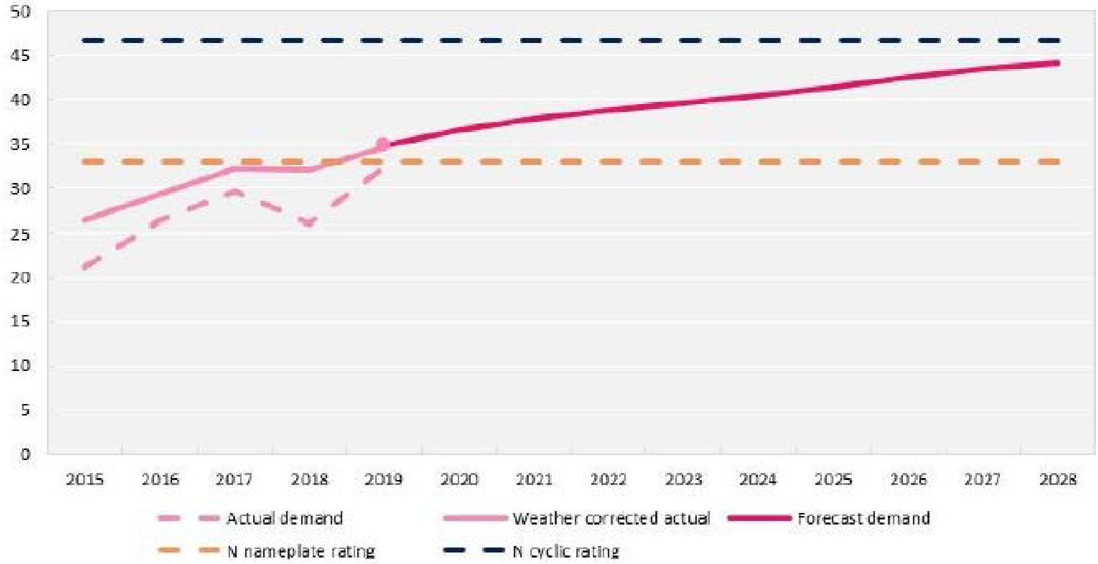
Our assessment

There is sufficient evidence for taking action at KBH substation within the next 10 years

560. United Energy's 10% PoE forecast for KBH substation is shown in the figure below. Growth in maximum demand is forecast to be 2.8% p.a. over the next 10 years.

561. After load transfers are established following a transformer outage, an 18 MVA shortfall in capacity in 2028 is forecast. Loss of supply could be to as many as 3,750 customers. The load transfer capacity is forecast by United Energy to decline over time at each substation. We consider this to be a reasonable assumption.

Figure 5.11: Keysborough substation maximum demand forecast (10% PoE, MW)



Source: United Energy, BUS 6.04, Figure 4

562. As shown in the figure below, United Energy forecasts that several feeders at KBH substation will exceed, or come close to exceeding, their respective utilisation ratings in the next RCP.

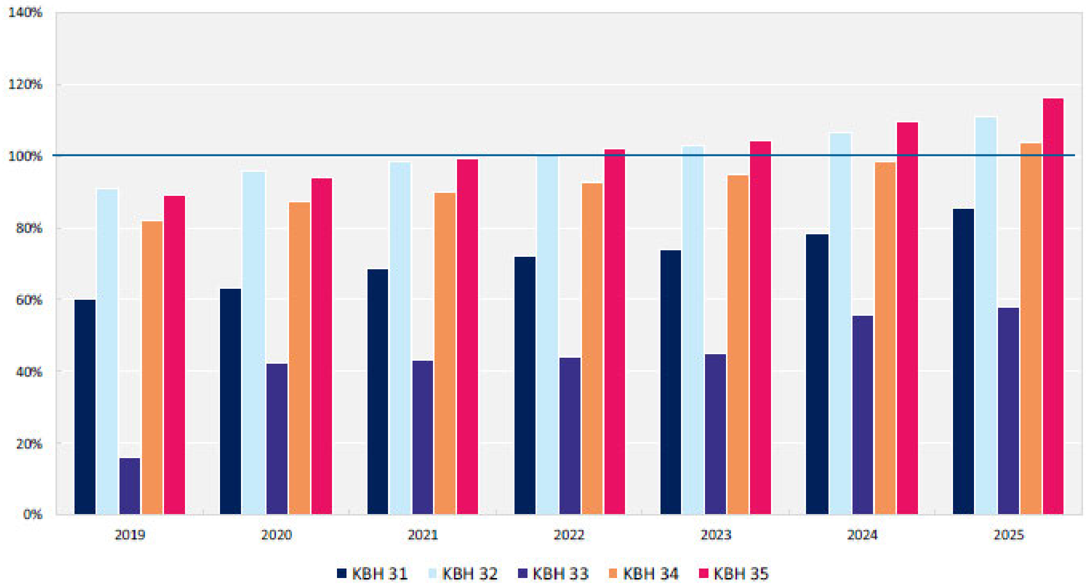
563. From the KBH substation load duration curve presented as Figure 7 in the business case, approximately 15% of the peak demand experienced is 2% (175 hrs) per year. This means that at peak times, the high utilisation of a large number of feeders could be operationally problematic, but the amount of time that the feeders exceed 90% loading could be much less than 2% per year.

564. If United Energy had presented the feeder utilisation forecasts based on 50%PoE demand, which, by definition, is the median of the outcomes, the graph may have shown that feeder utilisations do not exceed 100% by the end of the next RCP (or if they do it would be by a

[176] United Energy BUS 6.04 Keysborough supply area, page 9

small amount and for relatively short periods of time). Nonetheless, feeder utilisation is high on three of the feeders.

Figure 5.12: Keysborough supply area feeder utilisation forecast (10%PoE)



Source: United Energy, BUS 6.04, Figure 5

United Energy’s VCR for the economic analysis is not reasonable

565. United Energy has applied a weighted average $42,760 VCR in its model. United Energy states that ‘*KBH supplies predominantly residential customers, with a mix of light industrial and commercial establishments.*’[177] In the absence of any other detail on customer segment demand from United Energy, and cognisant that an individual commercial or industrial customer will demand more energy than an individual residential customer, we consider that a 60%10%:30% residential/commercial/industrial weighting[178] is a more reasonable input assumption. This results in a weighted average VCR for KBH substation of $35,231.

566. The result of applying this input assumption is discussed below.

United Energy’s economic analysis is limited

567. We found the same issues with United Energy’s KBH model as we described for the Doncaster substation model. In summary, despite the limitations with the model, we consider that we can still use the model in conjunction with the information provided in the business case to support our assessment.

The expected energy at risk should be reduced by accounting for the relocatable transformer

568. United Energy advised that the relocatable transformer can be mobilised and connected at KBH substation within 48 hours, despite the transformers being stored in-service (i.e., they are not ‘cold spares’).[179] It is not clear from the economic model whether this has been accounted for; however, the business case refers to this facility.

177 United Energy BUS 6.04 Keysborough supply area, page 5

178 Residential VCR = $26,800/MWh; Commercial $48,410/MWh; Industrial $47,700

179 United Energy BUS 6.04 Keysborough supply area, page 12

Option 1 or Option 5 is likely to be the prudent approach (but with delayed timing)

569. United Energy considered six options in addition to 'Do nothing', as shown in the table below. Its preferred approach is Option 1. The net economic benefit is measured against the Option 0 counterfactual.

Table 5.7: Keysborough supply area - summary of United Energy's options analysis - $m, real 2019

Option	NPV benefit
0 Maintain the status-quo	N/A
1 KBH second transformer and two new feeders	3.1
2 Permanent load transfer to adjacent zone substations via feeder works	1.9
3 Permanent load transfer followed by KBH second transformer and one new feeder	3.0
4 Improved load transfer followed by KBH second transformer and two new feeders	2.7
5 Non-network solution to defer preferred network option	2.9
6 Power factor correction	N/A

Source: United Energy BUS 6.04, Table 2 and UE MOD 6.07. Note: n/a means not available from United Energy's analysis

570. Option 0 is unlikely to be the prudent solution given the loading level on the substation and the risk and consequence of transformer and 66kV line outages. Option 6 was not considered credible because United Energy advised that the power factor is already close to unity.

571. Option 2 as presented by United Energy has a lower net benefit than Option 1 and a lower capital cost. As discussed above, we consider this analysis to be flawed because of limitations in the model. However, from the description of the subsidiary work to enable a more balanced comparison with the merits of the other options, we consider that it is likely to cost as much as Option 3 (or more).

572. Option 3 has a 5% higher capital cost than Option 1 with a similar net benefit. It defers the timing of the 2nd KBH transformer by one year based on United Energy's analysis. In the economic model, the permanent transfer work is scheduled for 2020 at a cost of $2.0m, which is a year prior to providing any augmentation under the other augmentation options. The reason for this is not clear but deferring the permanent transfer by 2-3 years (which we consider to be feasible based on the information provided) is likely to result in the Option 3 net benefits being higher than Option 1's. The advantage of Option 3 over Option 1 is that it offers the potential to defer the KBH second transformer if the load growth is not as strong as forecast. We discuss this further below.

573. Option 4 provides a 6MVA additional transfer capacity in the case of a transformer circuit outage. The capital cost is higher and the NPV benefit is lower than Options 1, 3 and 4 and it is therefore unlikely to be the prudent approach.

574. Option 5 is based on $87,000/MW for NNS, which we consider to be a reasonable assumption based on the evidence provided.[180] The table below shows United Energy's estimate of the amount of NNS required to '*…bring the station load at risk back to the previous year's level and defer by one year the need for the balance of the option…*'[181]

575. The NNS would defer Option 1 augmentation by one year.

[180] United Energy, Attachment UE ATT102 - CulterMerz - Review of demand management - Feb2019 - Public, CutlerMerz, Review of demand management unit rates

[181] United Energy BUS 6.04 – Keysborough supply area, page 16

Table 5.8: United Energy's Keysborough substation estimated Non network support requirement (MW)

	2021	2022	2023	2024	2025
Peak demand at risk after load transfers (10%PoE)	6.5	8.3	9.9	11.1	12.8
Non network support required	0.0	0.0	2.1	2.4	2.7

Source: United Energy BUS 6.04, Table 7, page 16

576. United Energy dismissed this option despite promoting the considerable success of its Summer Saver program as a means of deferring network capital. However, we consider that, if required, 2-3MW of NNS may be a practical and economic option to defer capital investment in network options at one or more of the three substations due to the relatively low peak demand growth forecast.

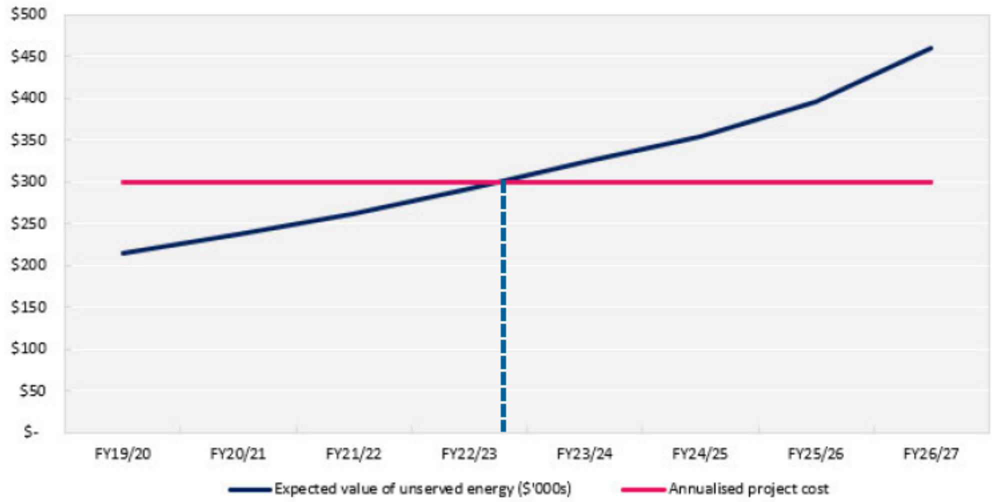
577. United Energy's preferred Option 1 includes installation of a second KBH transformer and two new feeders to manage feeder utilisation constraints. It has (marginally) the highest NPV and the lowest capital cost of the credible options.

578. Based on our review of United Energy's analysis, we consider that Option 1 is superior to Options 0, 2, and 6. However we consider that Option 3 has considerable merit if demand growth is lower than United Energy forecasts. The use of NNS, perhaps via United Energy's Summer Saver program, may also be an economically prudent 'sub-option'.

The economically optimum timing is likely to be 2026/27 but with Option 3

579. United Energy's probabilistic planning model, with its weighted demand forecast, load transfer and VCR assumptions, leads to 2023/24 as the economically optimum timing[182] for Option 1, as shown in the figure below. We note that United Energy plans to complete the work in 2022/23.

Figure 5.13: Keysborough supply area - UE's assessment of ENS vs annualised cost of Option 1 - $k, real 2019



Source: United Energy, UE MOD 6.07

182 The point at which the annual value of unexpected unserved energy exceeds the levelised (or annualised) cost of the solution to 'avoid' the risk cost is the economically optimum timing'

580. United Energy undertook a sensitivity analysis under 'best' and 'worst' case scenarios and concluded that Option 1 was still the preferred solution. It did not consider the sensitivity of the timing of the proposed work to these scenarios.[183]

581. We therefore undertook our own sensitivity analysis, using United Energy's model with:

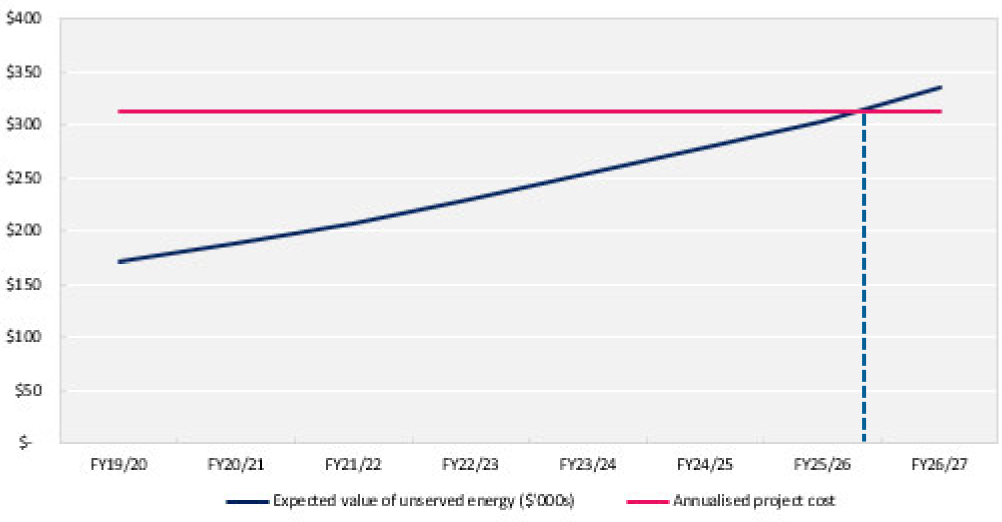
- Our substituted VCR value ($35,231/MWhr), as discussed earlier;
- 100% weighting to the 50% PoE demand forecast (giving a lower expected unserved energy) as a proxy for a lower demand growth rate (but with United Energy's VCR value);
- Our substituted VCR value plus 100% weighting to 50%PoE demand forecast.

582. We also updated the model with the actual weather corrected peak demand from 2019 and 2020 provided by United Energy.[184] Applying the alternative VCR value defers Option 1 to 2024/25. Applying only the alternative demand forecast weighting does not defer the project. The result of applying the two EMCa input assumptions defers Option 1 to 2025/26.

583. We also studied the sensitivity of Option 3 to the EMCa input assumptions. Applying the alternative VCR value defers Option 3 to 2025/26. Applying only the alternative demand forecast weighting defers Option 3 to 2024/25. The result of applying the two EMCa input assumptions defers Option 3 to 2026/27. This would reduce the capex requirement for the Keysborough supply area to $4.0m (i.e., an adjustment of -$2.6m).

584. With the deferral of the Option 3 permanent load transfer work into 2021/22 (i.e., rather than in 2019/20, as modelled), the net benefit of Option 3 is likely to be close to that of Option 1.[185] As stated earlier, the advantage of Option 3 is that it provides the possibility to defer the installation of the 2nd transformer for a few more years if load growth is not as strong as forecast.

Figure 5.14: EMCa sensitivity study – KBH energy not served vs annualised cost of Option 3 - $k, real 2019



Source: United Energy, MOD 6.07 with EMCa revised inputs: VCR = $35,231; 100% weighting to 50%PoE

Cost estimate for Option 3 is likely to be similar to Option 1

585. The Option 1 and Option 3 capital costs are the same in United Energy's spreadsheet. We understand that United Energy has recent experience in designing, costing, and delivering substation brownfield work and HV feeder-related work, and it should therefore have reasonable building-block information for this project. On this basis we consider that it is

[183] United Energy UE BUS 6.04 – Keysborough supply area, page 17

[184] United Energy response to AER information request IR021

[185] Modelling limitations do not allow this to be determined

likely that the cost estimate for Option 3 at $6.6m (from UE MOD 6.07) for the permanent load transfer, 2nd transformer, and extra feeder is likely to be reasonable.

Summary

586. We consider that United Energy has presented a case for taking action within the next decade to address the forecast peak demand growth and energy-at-risk in the Keysborough supply area.

587. Using United Energy's model, we have analysed the sensitivity of the option selection and timing to two key input assumptions: the assumed VCR and the demand forecast weighting. We applied (i) a VCR that we consider is likely to better reflect the actual characteristics of the supply area, rather than the Victorian average VCR which United Energy has assumed, and (ii) 100% weighting to the 50% PoE demand forecast.

588. The results suggest that Option 3 rather than Option 1 is likely to be the more prudent augmentation approach. Option 3 would provide 'option value' in that if load growth is lower than forecast, the second KBH substation transformer may be able to be prudently deferred beyond the next RCP, perhaps with a relatively small amount of non-network support. We note that United Energy has successfully and economically applied its Summer Saver program in similar circumstances.

5.4.5 Mornington area strategy

Overview of project

589. Mornington (MTN) substation supplies 23,000 customers and is one of the fasted growing suburbs on the Mornington Peninsular.

590. MTN substation was rebuilt in 2012 with two 66/22kV 20/33MVA transformers and eight 22kV feeders. There is one spare feeder circuit breaker. It is designed to accommodate three transformers and host a relocatable transformer.

591. Peak demand is above the N-1 capacity but below the N cyclic rating. Several MTN substation feeders are forecast to exceed 100% utilisation within the next RCP.

592. To address the risks posed by the increasing load, United Energy propose:

- Staged installation of two new feeders at MTN substation; and
- Installation of a third transformer at MTN zone substation.

593. United Energy refer to this as Option 1. The forecast capital cost is $7.6m. The project is planned to start in 2020/21 and be completed by 2025/26.

594. United Energy propose to install a third MTN substation transformer with a new feeder by December 2025 at a forecast capital cost of $7.1m. This is the second stage of a two-stage project which commenced with establishing a new feeder at MTN substation and reconfiguring the distribution network. This first stage is scheduled to start in 2020/21 and be completed in 2021/22 at a total cost of $0.9m (with $0.5m in 2021/22).

Our assessment

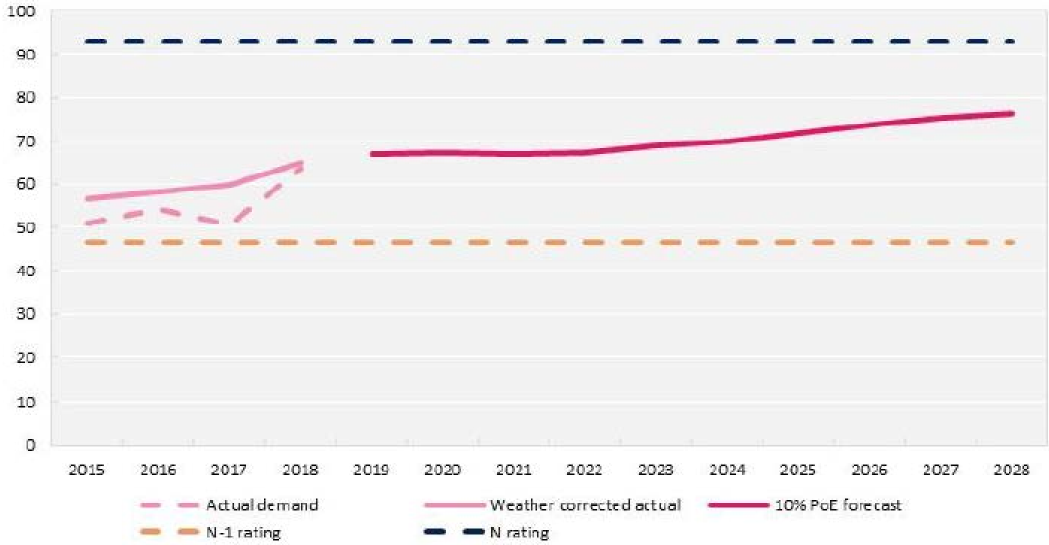
595. With the exception of the business case's section 5 (Recommendation), which includes an updated timing assessment for stage 2 only (i.e. following completion of the stage 1 MTN feeder), the business case and the supporting model have been derived with stage 1 of the project included as part of the options analysis. As noted above, the stage 1 MTN feeder is scheduled to be commissioned by 2021/22. We first reviewed the business case and model as presented and then updated our findings based on the adjustment to timing evident from the revised information in section 5 of the business case.

There is sufficient evidence for taking action at MTN substation within the next 10 years

596. United Energy's 10% PoE forecast for MTN substation is shown in the figure below. Peak demand is forecast to increase by 1.4% per annum over the next 10 years.

597. After load transfers are established following a transformer outage, a shortfall of 17MVA is forecast in 2028. Loss of supply could be to as many as 7,000 customers. The load transfer capacity is forecast by United Energy to decline over time at each substation. We consider this to be a reasonable assumption.

Figure 5.15: Mornington substation maximum demand forecast (10% PoE, MW)



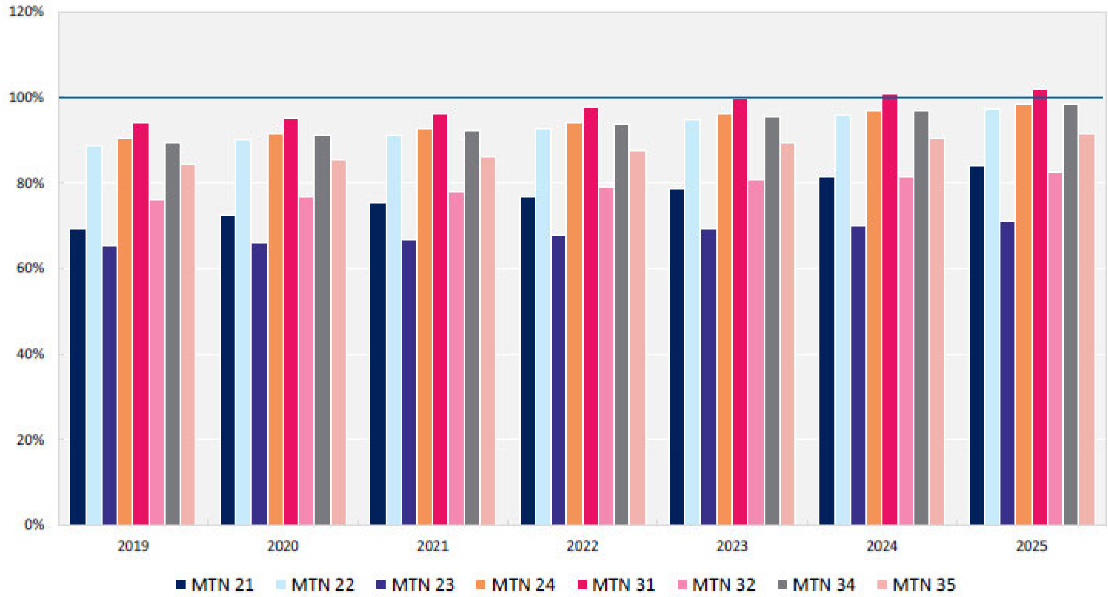
Source: United Energy BUS 6.05, Figure 4

598. As shown in the figure below, United Energy forecasts that one feeder at MTN substation will exceed 100% utilisation at peak in 2025, and several others have high utilisation.

599. From the MTN substation load duration curve presented as Figure 7 in the business case, approximately 30% of the peak demand is experienced 2% (175 hrs) per year. This means that at peak times, the high utilisation of a large number of feeders could be operationally problematic, but the amount of time that the feeders exceed 80% loading could be much less than 2% per year.

600. If United Energy had presented the feeder utilisation forecasts based on 50%PoE demand, which, by definition, is the median of the outcomes, the graph may have shown that feeder utilisations do not exceed 100% by the end of the next RCP (or if they do it would be by a small amount and for relatively short periods of time). Nonetheless, feeder utilisation is high on five feeders.

Figure 5.16: Mornington supply area feeder utilisation forecast (10%PoE)



Source: United Energy BUS 6.05, Figure 5

United Energy's VCR for the economic analysis is not reasonable

601. United Energy has applied a weighted average $42,760 VCR in its model. United Energy states that *'[t]hese customers are predominantly residential, with a mix of light industrial and commercial establishments*'. On the same basis as our adjustment for the Keysborough supply area, we consider that a weighted VCR based on a 60%:10%:30% residential/commercial/industrial PoE weighting[186] is a more reasonable base input assumption. This alternative assumption results in a weighted average VCR for MTN substation of $35,231/MWh.

602. The result of applying this input assumption is discussed below.

United Energy's economic analysis is limited

603. We found the same issues with United Energy's MTN model most as with the Doncaster model. In summary, we consider that we can still use the model in conjunction with the information in the business case to support our assessment.

The expected energy at risk should be reduced by accounting for the relocatable transformer

604. United Energy advises that the relocatable transformer can be mobilised and connected at MTN substation within 5 days, despite the transformers being in-service (i.e., they are not 'cold spares').[187] It is not clear from the economic model whether this has been accounted for, however the business case repeatedly refers to this facility.

Option 1 is the prudent approach (but with delayed timing)

605. United Energy considered six options in addition to 'Do nothing', as shown in the table below. Its preferred approach is Option 1. The net economic benefit is measured against the Option 0 counterfactual.

186 Residential VCR = $26,800/MWh; Commercial $48,410/MWh; Industrial $47,700

187 United Energy BUS 6.05 Mornington supply area, page 12; noting that in the case of the relocatable transformer for Keysborough substation, the relocation time is quoted as for the KBH business case (page 12)

Table 5.9: Mornington supply area – summary of United Energy's options analysis - $m, real 2019

Option	NPV Net Benefit
0 Maintain the status-quo	n/a
1 MTN33 feeder followed by MTN 3rd transformer and second new feeder	5.1
2 MTN 3rd transformer with two new feeders	5.0
3 Permanent load transfer to adjacent zone substations via feeder works	0.7
4 Permanent load transfer followed by MTN 3rd transformer and one new feeder	5.0
5 Non-network solution to defer preferred network option	4.9
6 Power factor correction	n/a

Source: United Energy UE BUS 6.05, Table 2 and UE MOD 6.08
Note: n/a means not available from United Energy's analysis

606. Option 0 is unlikely to be the prudent solution given the loading level on the substation and the risk and consequence of transformer and 66kV line outages. Option 6 was not considered credible because United Energy advised that the power factor is already close to unity.

607. Option 2 is marginally cheaper than Option 1 with a marginally lower net benefit. Feeder works are completed with the third transformer (rather than in two stages, before and after the transformer, as in Option 1). The key disadvantage of this option is that it reduces the opportunity to defer the third transformer (e.g., if load growth slows).

608. Option 3 as presented by United Energy has much lower net benefit than Option 1 and a much lower capital cost. As discussed above, we consider this analysis to be flawed because of limitations in the model. However, from the description of the subsidiary work to enable a more balanced comparison with the merits of the other options, we consider that it is likely to cost as much as Option 4 (or more).

609. Option 4 has a slightly higher capital cost than Option 1 with a similar NPV. In the economic model, the permanent transfer work scheduled for 2020/21 – 2021/22 at a total cost of $0.9m ($0.5m in 2021/22), which is a year earlier than any augmentation under the other options. The reason for this is not clear but deferring the transfer work by even one year is likely to give the same net benefit as Option 1. The advantage of Option 3 over Option 1 is that it offers the potential to defer the MTN third transformer if the load growth is not as strong as forecast. On the downside, the incremental capital cost is $0.2m ($2019) higher than Option 1 for little incremental benefit. On balance, it is unlikely to be the prudent approach.

610. Option 5 is based on $87,000/MW for NNS, which we consider to be a reasonable assumption based on the evidence provided.[188] The table below shows United Energy's estimate of the amount of NNS required to '*…bring the station load at risk back to the previous year's level and defer by one year the need for the balance of the option…*'[189]

611. The NNS defers Option 1 augmentation by one year.

Table 5.10: United Energy's Mornington substation estimated Non network support requirement (MW)

	2024	2025	2026	2027	2028
Peak demand at risk after load transfers (10%PoE)	9.0	11.3	13.6	15.7	16.6
Non network support required	0.0	0.0	2.3	4.4	5.2

Source: United Energy BUS 6.05, Table 7, page 16

188 United Energy, Attachment UE ATT102 - CulterMerz - Review of demand management - Feb2019 - Public, CutlerMerz, Review of demand management unit rates

189 United Energy BUS 6.05 –Mornington supply area, page 16

612. United Energy dismissed this option despite promoting the considerable success of its Summer Saver program as a means of deferring network capital. However, we consider that, if required, 2-3MW of NNS may be a practical and economic option to defer capital investment in network options at one or more of the three substations due to the relatively low peak demand growth forecast.

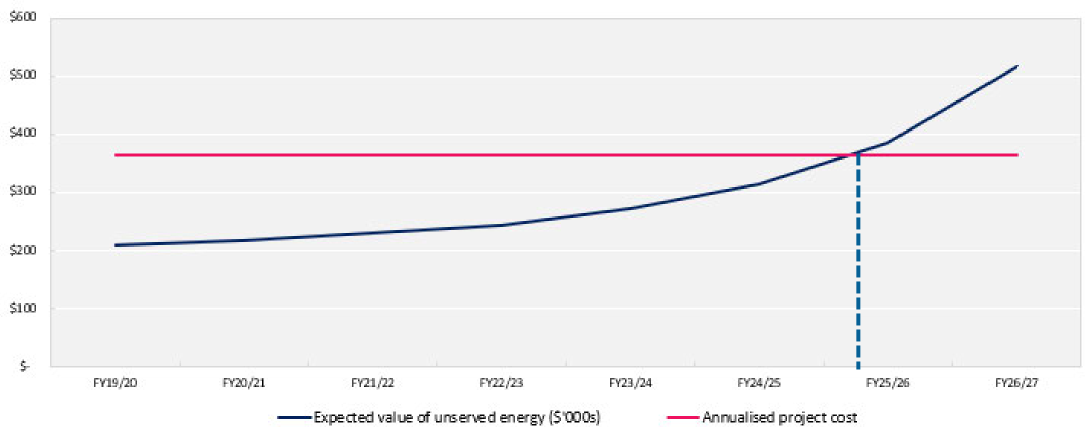
613. United Energy's preferred Option 1 is based on first installing a new feeder by 2021/22 (to help offload the highly utilised feeders) and then installing a third transformer and another feeder at MTN substation by 2025/26. Option 1 has (marginally) the highest net benefit and the second lowest capital cost of the credible options.

614. Based on our review of United Energy's analysis, we agree that Option 1 is superior to the other options. However, we consider that United Energy should not dismiss the application of NNS (Option 5) as a means of deferring capital investment.

The economically optimum timing is likely to be beyond the end of the next RCP

615. United Energy's probabilistic planning model with its weighted demand forecast, load transfer, and VCR assumptions results in 2025/26 as the economically optimum timing[190] for Option 1, as shown in the figure below. United Energy plans to complete the work in 2025/26.

Figure 5.17: Mornington supply area – UE's assessment of ENS vs annualised cost of Option 1 - $k, real 2019



Source: United Energy MOD 6.08

616. United Energy undertook a sensitivity analysis under 'best' and 'worst' case scenarios and concluded that:[191]

- Worst-case scenario – Option 1 is still preferred; and
- Best-case scenario – Option 2 (MTN third transformer with two new feeders) has higher net economic benefits and would be preferred.

617. United Energy did not consider the sensitivity of the timing of the proposed work to these scenarios. We therefore undertook our own sensitivity analysis, using United Energy's model with:

- Our substituted VCR value, as discussed earlier;
- 100% weighting to the 50% PoE demand forecast (giving a lower expected unserved energy) as a proxy for a lower demand growth rate (but with United Energy's VCR value); and
- Our substituted VCR value plus 100% weighting to the 50% PoE demand forecast.

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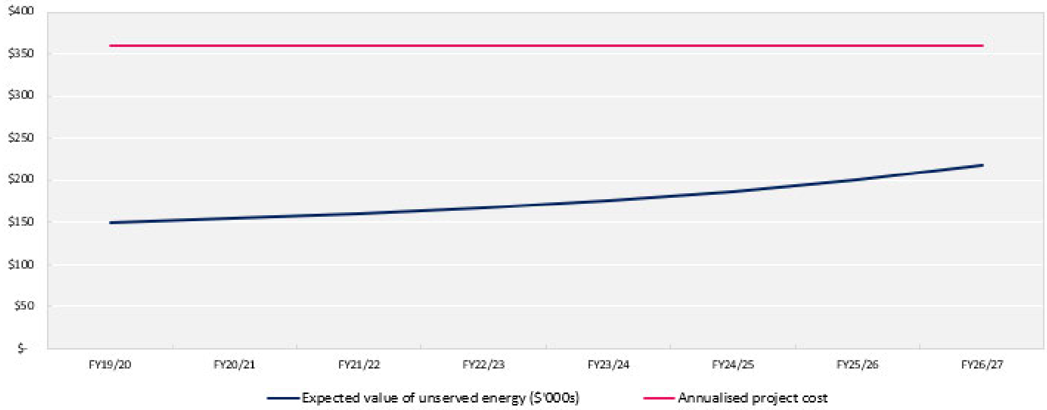
190 The point at which the annual value of unexpected unserved energy exceeds the levelised (or annualised) cost of the solution to 'avoid' the risk cost is the economically optimum timing'

191 United Energy UE BUS 6.05 – Mornington supply area, page 17

618. We also updated the model with the actual weather corrected peak demand from 2019 and 2020 provided by United Energy.[192] Applying the revised VCR value defers Option 1 to 2026/27. Applying only the alternative demand forecast weighting defers Option 1 well beyond the next RCP. The result of applying the two ‘EMCa’ inputs assumptions is shown in the figure below, with the impact being that the economic timing of Option 1 is deferred well beyond the next RCP. This approach would reduce the capex requirement in the next RCP to $0.5m to complete the stage 1 MTN feeder (i.e., an adjustment of -$6.6m).

619. Although we have reservations about the NPV calculations (as discussed above), it is likely that Option 1 retains its slight economic advantage over the other options with the revised input assumptions.

Figure 5.18: EMCa sensitivity study – energy not served vs annualised cost of Option 1 - $k, real 2019



Source: United Energy, MOD 6.08 with EMCa revised inputs: VCR = $33,131; 100% weighting to 50%PoE

Updated analysis post-stage 1 installation does not change our finding

620. In the Recommendation section of its business case, United Energy presents an updated diagram showing the expected unserved energy vs annualised project cost after the installation of the MTN feeder. The expected unserved energy curve is flatter after transfer of load early in the next RCP and the economically optimum timing for stage 2 is deferred, but still indicates that Option 1 (stage 2) should be completed in 2025/26, using United Energy’s modelling assumptions.

621. Based on United Energy’s updated analysis, but with what we consider to be more reasonable input assumptions, the economic timing for stage 2 would still be beyond the next RCP.

Summary

622. We consider that United Energy has presented a case for taking action within the next decade to address the forecast peak demand growth and energy-at-risk in the Mornington supply area.

623. Using United Energy’s model, we have analysed the sensitivity of the option selection and timing to two key input assumptions: the assumed VCR and the demand forecast weighting. We applied (i) a VCR that we consider is likely to better reflect the actual characteristics of the supply area, rather than the Victorian average VCR which United Energy has assumed, and (ii) 100% weighting to the 50% PoE demand forecast.

624. The results suggest that Option 1 is likely to be the prudent augmentation approach, with the new MTN feeder completed as stage 1 in the next RCP as planned, but the third MTN substation transformer and second new feeder may be able to be prudently deferred beyond the next RCP.

192 United Energy response to AER information request IR021

5.4.6 Remainder of 2021-2026 capex

The remaining $1.7m capex is directed to installation of load shedding schemes

625. United Energy has forecast $1.7m for installing automatic load shedding schemes at nine substations at a cost of approximately $0.2m over two years for each substation.

Observations

626. Automatic load shedding schemes are to help prevent cascading failures and/or total loss of supply.[193] United Energy's Network Planning Guidelines confirm that automatic load shedding schemes are to prevent transformers from damage due to excessive loading and outline the cases in which they should be considered:[194]

> *'Augmenting a two-transformer zone substation with sub-transmission line breakers or an automatic load shedding scheme should be considered for inclusion in the Demand Strategy and Plan in the year the following conditions apply:*
>
> * *The forecast station load exceeds the 2-hour emergency rating; or*
>
> * *The value of the energy at risk does not warrant the installation of a third transformer.*

627. Two of the schemes are planned to commence in 2025/26 and one scheme is scheduled to commence in 2020/21.

628. Two of the planned schemes are at Caufield (CFD) and Gardiner (K) substations in the Malvern supply areas. The peak demand is forecast to exceed the N-1 capacity within the next RCP. Based on the recommended approach to augment Malvern substation, not CFD or K substations, these latter substations would appear to satisfy the criteria.

629. Similar comments apply to the three schemes planned to be installed at substations in the Mornington supply area: Frankston South (FSH), Sorrento (STO), and Rosebud (RBD).

630. On the basis that: (i) five of the nine planned load shedding schemes have a reasonable basis for proceeding as planned; and (ii) United Energy has recent experience in installing these schemes, it is reasonable to assume that the other four are justified and that the unit cost is reasonable.

5.5 Subtransmission lines

Overview

631. Only four demand-driven subtransmission lines projects are planned for the next RCP, with total capex of $1.2m:

- Sub-transmission feeder works – CBTS ($0.6m);
- BT-MR 66kV - thermal uprate ($0.2m);
- GWNO combine with EB loop ($0.2m); and
- Upgrade disconnector & droppers switch on TSTS-DC #2 ($0.1m).

Observations

632. The feeder work associated with CB Terminal Station is '*the UE capex component of CBTS fourth transformer project required for the relocation of UE sub-transmission line assets.'*[195] Reference is also made to UE BUS 9.04 for the approach. The justification for this

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193 United Energy response to AER information request IR011, Project list 6.01

194 United Energy Network Planning Guidelines | Document No. UE GU 2200 | Version 10, page 61

195 United Energy response to AER information request IR011, Project list 6.01

component is likely to be dependent on the AER's assessment of the prudency and efficiency of the expenditure supported by that business case.

633. The approach for the three other projects is based on when '… *the annualised value of the energy-at-risk exceeds the annualised capital cost of the investment with the preferred option being the one that delivers the least lifecycle cost.'*[196] United Energy provides no further justification, noting that the criterion stipulated is consistent with United Energy's approach to determining the economic timing of projects.

5.6 HV Feeders

5.6.1 Feeder projects associated with Focus Projects

634. Three feeder projects with total forecast capex of $4.7m are associated with the proposed augmentation solution for the Malvern supply area discussed in section 5.4.3. One feeder project with total forecast capex of $1.0m ($0.5m in the next RCP) is associated with the proposed augmentation solution for the Mornington supply area, as discussed in section 5.4.5.

5.6.2 Key Feeder projects

Overview

635. United Energy has provided a business case[197] covering eight projects[198] which are forecast to incur a total of $11.0m capex in the next RCP, as shown in the table below. In the table, we have incorporated the expenditure shown in United Energy's Project List[199] which only includes the capex in the next RCP, whereas the business case also includes planned capex in the current RCP.[200]

Table 5.11: United Energy's key feeder projects: 2021-2026 regulatory period -$m, real 2021

Feeder project	Optimal year for commissioning	DM deferral period (years)	Cost in 2021-2026 RCP
Install new HGS 11 feeder	2021/22	4	1.0
Install new OR feeder	2021/22	3	0.8
RBD 11 Feeder Extension	2022/23	2	2.2
Install new feeder FSH 24	2022/23	4	1.7
Install new feeder DSH 12	2022/23	-	1.0
Install new EB feeder	2024/25	1	1.6
Install new WD feeder	2024/25	1	1.1
Install new LD34 feeder	2025/26	2	1.6
Total			**11.0**

Source: United Energy response to AER IR011, question 3 - Project list 6.01 and Table 1.1 in United Energy BUS 6.07

[196] United Energy Network Planning Guidelines | Document No. UE GU 2200 | Version 10, page 12

[197] United Energy BUS 6.07 - HV feeder upgrades

[198] Two other projects are scheduled for completion in the current RCP

[199] United Energy response to AER IR011, question 3 - Project list 6.01

[200] United Energy BUS 6.07 - HV feeder upgrades

Observations

Two of the projects are underway

636. The new HGS feeder and OR feeder projects are scheduled to commence in the current RCP and finish in 2021/22. The remaining six projects are all scheduled to start and finish in the next RCP

United Energy's solutions 'tool kit' for thermal or PQ issues are consistent with industry practices

637. United Energy states that it considers a number of options 'in identifying suitable mitigation measures to alleviate thermal capacity and transfer capacity issues on distribution feeders',[201] including:

- permanent load transfers to neighbouring feeders;
- feeder reconductoring;
- thermal uprate;
- reactive power compensation;
- new feeder ties or extensions;
- new feeders; and
- non-network alternatives.

638. These solutions are consistent with the approaches taken within the industry to address distribution feeder thermal and power quality (typically voltage) issues related to high supply demand.[202]

639. The eight projects each address feeder utilisation issues.

640. The proposed new FSH feeder project scheduled for completion in 2022/23 illustrates United Energy's approach to justifying the augmentations. The figure below shows the current predicted (not treated) and treated feeder utilisations. As is the case in the other seven projects, network augmentation and NNS options are considered, with the lowest cost option selected. In this case the comparison is between: (i) thermal uprate/reconductoring of FSH 31; (ii) a new FSH 24 feeder ($1.7m); and (iii) 0.6 MW of demand side management (or NNS, for a four-year deferral). United Energy appears to have applied the NNS option, given the benefit of deferring $1.7m for 4 years would more than offset the additional opex of approximately $52,000 p.a.[203]

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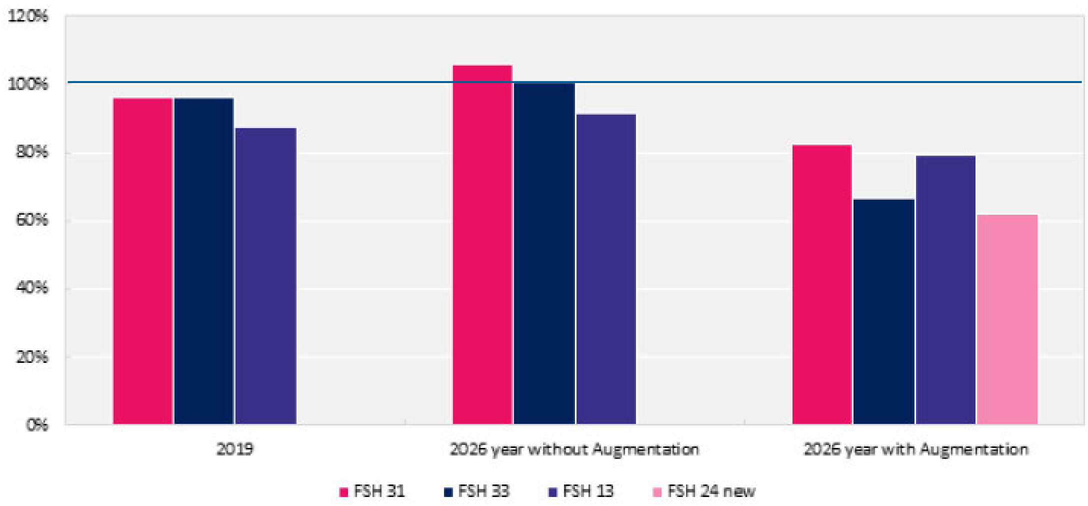
201 United Energy BUS 6.07 - HV feeder upgrades, page 6

202 Statcoms have also been used in some states to provide voltage regulation, which is not mentioned in any of the solutions proposed in the large projects that are the subject of UE BUS 6.07

203 Based on $87,000/MWh (as discussed elsewhere in this report)

Figure 5.19: Forecast FSH feeder utilisation (selected feeders)



Source: United Energy BUS 6.07, Figure 3.1, p9

The impact of lower than forecast demand growth may be significant

641. Lower growth than forecast by United Energy may allow further prudent deferral of projects currently planned for completion in the last one or two years of the next RCP perhaps with prolonged application of NNS.

642. United Energy has not provided an economic model to support its analysis. We expect that sensitivity analyses (e.g., lower demand forecast) would show that there is a reasonable likelihood of being able to economically defer some of the planned work beyond the next RCP. This is because in some cases, the duration of excursions of load above 100% utilisation is likely to be small at substations with minor 'breaches' of the 100% level with the current demand forecast assumption.

5.6.3 Remainder of feeder project expenditure

Overview

643. The remaining expenditure in this category covers:[204]

- 23 feeder projects with a combined capex forecast of $5.9m; and
- One project which is described as 'Demand Management – HV feeders' with total capex of $1.8m in the next RCP.

Assessment

644. All 23 feeder projects are demand-driven and reference is made to the expenditure forecasting approach in United Energy's Regulatory Proposal,[205] which we have commented upon in section 5.3. The projects fall into one of two groups:

- The first is an ongoing program to fit HV switches that allow load transfers between adjacent feeders to balance demand (total regulatory period expenditure is $1.0m). United Energy provides no further justification of this forecast capex; and
- The remaining 22 projects are various feeder reconductoring, works to facilitate load transfers, new feeders, feeder extensions and other unspecified upgrades. Each project is forecast to cost an average of $0.2m in the next RCP. It is unclear what part of section 6.1.2 of their Regulatory Proposal provides further information about these projects.

[204] United Energy MOD 6.01

[205] United Energy Regulatory Proposal 2021-2026, Section 6.1.2

645. 11 of the 22 feeder augmentation projects in the second group are set to commence in the final year of the regulatory period (2025/26) with forecast expenditure totalling $1.7m. Even a slight reduction in peak demand growth over the next five years is likely to provide the opportunity to defer some expenditure beyond the next RCP.

646. The ‘Demand management project’ includes capex reductions from 2019/20 to 2022/23 totalling $9.2m. In the balance of the next RCP, capital costs of $6.4m are accumulated.

5.7 Distribution Substations and LV Feeders

5.7.1 Introduction

647. There are three programs in the next RCP: (i) Distribution substations (DSS) P1, P2 and P3 annual programs which includes LV feeder (also referred to as LV circuit) upgrades; (ii) Pole transformer upgrades (and associated LV circuits), and (iii) the remainder, which comprises capex reductions from demand management programs from the Summer Saver program.

648. We discuss items (i) and (iii) together in section 5.7.2.

5.7.2 DSS P1, P2, P3 annual programs

Overview

649. The DSS program is a continuation of an ongoing program to address overloaded distribution substations and LV circuits which would otherwise lead to asset failure and outages in peak summer weather conditions.[206]

650. The DSS program expenditure is split between the Distribution Substations category ($18.0m) and LV Feeders ($6.1m) category. There is also offsetting DSS Demand management capex from the Summer Saver Program. In presenting our observations below, we do not attempt to distinguish between the Distribution Substations and LV Feeders allocation.

Observations

The P1, P2, P3 programs refer to descending order of priority

651. Under the DSS program, UE proposes a staged, prioritised program (priority 1, 2 and 3 referred to as P1, P2 and P3):[207]

- P1 – sites with predicted fuse operation occurrences (i.e., customer outages) of three or more and/or actual peak utilisation greater than or equal to 160% of cyclic rating during the recent summer;
- P2 – sites with predicted fuse operation occurrences equal to two and/or actual peak utilisation greater than or equal to 140% of cyclic rating during the recent summer; and
- P3 – sites with predicted fuse operation occurrences equal to one and/or actual peak utilisation greater than or equal to 120% of cyclic rating during the recent summer.

652. The DSS forecasting methodology is based on an economic assessment comparing ‘the expected unserved energy cost of ‘doing nothing’ (status quo) at each site versus the lowest cost technically acceptable (LCTA) augmentation capex solution and the expected Summer Saver demand management program operating costs.’[208]

206 United Energy Regulatory Proposal 2021-2026, page 101

207 United Energy Regulatory Proposal 2021-2026, page 102

208 United Energy response to AER Information Request IR031, question 29

653. With the exception of our concerns about forecast unserved energy based on a 70:30 weighting between the 50% PoE and the 10% PoE discussed elsewhere in this report, United Energy's approach appears to be reasonable.

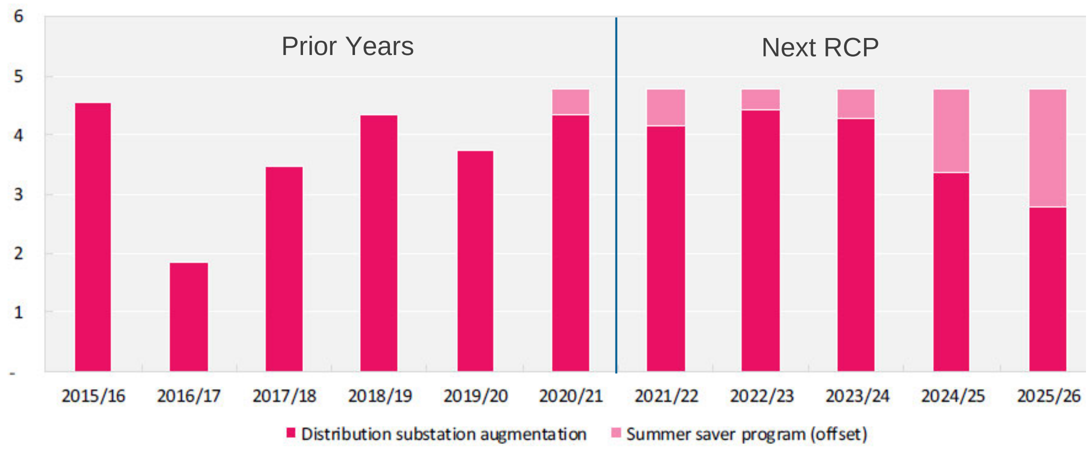
The proposed expenditure is less than the forecasting methodology identifies

654. United Energy advises that the forecasting methodology described above identifies around $40m augex for 820 distribution and LV circuit sites to be economically justified for augmentation from 2020 onwards.

655. As shown in the figure below, United Energy forecasts a reduction in the capex required due to '…the expansion of demand management [via its Summer Saver program] which we expect to continue to increase (further reduce capex) over time as more P3 sites are targeted for augmentation.[209]

656. Including the offsetting Summer Saver program, the average annual capex over the next RCP is slightly less than in the current RCP. Given United Energy's assessment approach, it is reasonable to assume that there is an adequate opex-capex trade-off in pursuing the Summer Saver Program.

Figure 5.20: United Energy propose distribution substation system augmentation -$m, real 2021



Source: United Energy Regulatory Proposal 2021-2026, Figure 6.6, page 103

Potential for overlap with the Solar enablement program is likely to be small

657. United Energy states that: '[w]e have ensured the investment proposed for maintaining our distribution substation system does not overlap with our solar enablement program…[t]he drivers for these works are fundamentally different…' [210]

658. Based on the information provided in addition to what we describe above, we consider that there is unlikely to be a material overlap with the Solar enablement program, particularly given the reduced volume of augmentation work that we propose with the latter.

Summary

659. We consider that the forecast expenditure may be biased towards overstating the actual efficient level because of our expressed concern with the forecasting methodology, but with that exception set aside: United Energy's approach and forecast capex (at about the same level as the current RCP) appears to be reasonable.

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[209] United Energy response to AER Information Request IR031, question 29

[210] United Energy Regulatory Proposal 2021-2026, page 103

5.7.3 Pole transformer upgrades (200-500kVA) and DSM (< 200kVA)

Overview

660. United Energy forecasts $4.0m for 200-500kVA pole transformer upgrades and $0.9m in the next RCP for upgrading smaller pole transformers in the Distributions Substation category. Similarly, it forecasts $1.3m for 200-500kVA pole transformer upgrades in the next RCP under the LV Feeders category and $0.3m for upgrading smaller pole top transformers.

Observations

661. The expenditure line items are for transformers that have failed due to overload and which will be replaced with a larger capacity transformer. United Energy states that the program '*is a unitised cost per volume program with the forward forecast based on the 2015-2018 historical averages.*'[211]

662. United Energy provides the historical actual unit rates from 2015-2018 for the 200-500kVA pole transformer upgrades, as shown in the table below. The reason for the average unit rate fluctuations from year to year are not explained, but we assume it is linked to the unique mix of transformer upgrade sizes in each year.

Table 5.12: Historical volumes and unit costs for 200-500kVA pole transformer upgrades - $2019

	2015	2016	2017	2018	Average
Volume	104	57	37	64	66
Unit rate	8,454	15,087	28,289	10,387	15,554
Forecast annual expenditure					**1,018,801**

Source: United Energy response to AER information request IR031

663. On this basis, we consider that a historical average is a reasonable approach to forecasting future requirements.

5.8 Other assets

5.8.1 Introduction

664. United Energy has proposed multiple projects in this expenditure category:

- Solar enablement ($42.4m);
- Communication devices: annual program ($6.9m);
- Digital network: network devices ($6.8m);
- Network communications: 3G shutdown ($6.0m);
- Communication devices: 5-minute settlement ($3.4m);
- Power quality ($3.2m);
- Upgrading of keys as a result of patent expiry ($3.1m); and
- Another 35 projects with aggregate forecast capex of $27.4m, for an average of $0.8m per project.

5.8.2 Solar enablement

665. This project is discussed as part of our assessment in section 6.

[211] United Energy response to AER Information Request IR031, question 29

5.8.3 Communication devices: annual program

666. United Energy states that this is a 'business-as-usual' installation program to install communications devices to enable transportation of AMI data into its IT systems. Forecasts are based on *'…2018 volumes escalated for the forecast growth rate in new metering connections and the historical rate of communication device failures.'* [212]

667. This project is discussed as part of our assessment of the 'parent' ICT project in section 7.

5.8.4 Digital network: network devices

668. This project is discussed as part of our assessment of the 'parent' ICT project in section 7.

5.8.5 Network communications: Telstra 3G retirement

Overview of project

669. United Energy's business case states that *Telstra's 3G communications network will be retired over the 2021–2026 regulatory period to make way for 5G technology.*[213] United Energy propose upgrading the devices or components of devices that currently operate on the Telstra 3G communications network.

Our assessment

670. United Energy quotes advice from Telstra dated 9 October 2019 that it would shut down its 3G network in 2024.[214] This affects many 3G devices that United Energy uses for operations. We have ascertained that United Energy'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 United Energy to exit from use of Telstra's 3G network by 2024.

671. United Energy considered three options to address the implications of the 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 United Energy's assessment, the net cost is the least negative and has a lower capital cost than Option 3.

672. Powercor and CitiPower have also proposed the same approach.

Justification for the cost estimate is likely to be reasonable

673. United Energy has identified 562 control boxes/RTUs/PQMs and 340 access points requiring replacement. The unit costs are derived from:

- materials costs - based on actual quoted rates for purchasing 4G equipment;
- labour rates - based on contracted rates; and
- labour time - based on internal estimates.

674. Based on the detail United Energy has provided and has included in its model,[215] we consider that United Energy's forecast capex is likely to be a reasonable estimate.

5.8.6 Communications devices: 5-minute settlement

675. This project is discussed as part of our assessment of the 'parent' ICT project in section 7.

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212 United Energy response to AER IR011 – Project list 6.01 – q3

213 United Energy BUS 6.01, page 5

214 UE ATT006 - Telstra 3G service closure - 2019 - Public Telstra. See also 3G Service Closure Redefine your business with a new generation of technology, 9 October 2019 <www.telstra.com.au/content/dam/shared-component-assets/tecom/campaigns/3g-exit/3G-Service-Closure_v2.pdf>

215 United Energy MOD 6.05 – 3G shutdown

5.8.7 Power quality

Overview of project

676. United Energy forecasts incurring $3.2m capex in the next RCP, as follows:

- $2.4m over the course of the next RCP on power quality rectification capex at a flat annual rate that ‘*addresses non-compliant low voltages at existing sites*’;[216] and
- $0.8m over the course of the next RCP on power quality meters (analysers).

Observations

Power quality rectification capex appears to be based on historical data

677. United Energy has not provided any insight into its forecasting methodology; however, the last two years of the current RCP have the same annual capex ($472k) as each year in the next RCP. We assumed that all seven annual amounts are forecasts and that the 2019/20 estimate is either a full year extrapolation of expenditure incurred to date in 2019/20 or, more likely, a repeat of the last available actual amount in 2018/19.

Power quality rectification capex is much lower than CitiPower’s and Powercor’s similarly-named programs

678. At a total of $2.4m with a flat expenditure profile, United Energy’s power quality capex is much lower than Powercor’s $11.0m and CitiPower’s at $8.2m, respectively, both of which have inclining forecast capex profiles.

679. The Powercor and CitiPower programs appear to cover a broader range of PQ issues than United Energy’s (low voltage only), so it is likely that the definitions differ.

Power quality meter/analyser capex is not explained in detail

680. United Energy advises that its forecast power quality expenditure includes:[217]

- MV feeder PQ meters - annual program to install PQ analysers at the end of MV feeders based on critical customer areas where known disturbing loads are connected; and
- Terminal station PQ meters - installed on buses at all Terminal Stations in order to monitor the performance of PQ against Use of System (UoS) Agreements.

681. The average cost of the Terminal Station analysers is $0.1m and five sites have been identified.

682. United Energy has allowed $60k per annum for the ongoing MV feeder analysers.

5.8.8 Upgrading of keys as a result of patent expiry

Overview

683. United Energy forecasts $3.1m capex in the next RCP for this program.

Observations

No economic modelling has been provided in support of the project

684. As no information was provided to support this multi-million dollar program in its Regulatory Proposal, we asked United Energy for additional information. In its response, United Energy states that:[218]

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216 United Energy response to AER IR011 – Project list 6.01 – q3

217 United Energy response to AER IR011 – Project list 6.01 – q3

218 United Energy Response to AER information request IR031, q29(vi)

- It currently uses 'mechanical keys and padlocks as the primary means of preventing unauthorised access to zone substations, ACRs, ground substations, kiosks, and air-break switches';
- Mechanical keys present 'security, reliability and safety risks'; and
- Electro-mechanical locksets, including integrated and automated systems to support real-time monitoring, have become the industry standard. It plans to replace them with *electro-mechanical keys and locking systems as its existing patents expire*.

Cheaper alternatives may be available

685. United Energy has not provided an options analysis (or a description of the options it has considered or may consider). However, it is apparent that it has based its cost on replacing the locks and keys and purchasing software and the software licence based on its selected option.

686. We are aware of an alternative to replacing the entire lockset that we understand is significantly less expensive.

5.8.9 Remaining projects

687. There are 35 remaining projects with total forecast expenditure of $27.4m. Brief descriptions of each project are provided, but there is insufficient information for the reasonableness of the expenditure to be established.

5.8.10 Summary

688. We have presented observations on only three programs in this category, noting that: (i) four programs are discussed elsewhere in this report; and (ii) there is insufficient supporting information provided for the remaining 35 projects to offer any observations about the proposed $27.4m capex.

689. Of the three programs for which we provided observations:

- 3G shutdown – we consider that it is prudent for United Energy to plan for the shutdown in 2024 and that the costs are likely to be reasonable;
- There is insufficient information provided in support of the PQ and the Key upgrade programs for us to make an assessment of the reasonableness of the forecast expenditure. We note that, in the case of the PQ program, forecast costs appear to reflect a historical level.

5.9 Findings and implications for United Energy's non-DER augex forecast

United Energy's probabilistic planning and economic modelling

690. We consider United Energy's probabilistic planning model to be reasonable with one exception: determining the value of unserved energy on a weighting of 70% of the demand forecast based on the 50% PoE forecast and 30% at the 10% PoE forecast. We also consider that use of the weighted substation VCR is preferrable to United Energy's application of the Victorian average VCR. We have sought to account for these issues by undertaking our own sensitivity analyses using United Energy's models (where they are available) to test the robustness of the selected options and the timing of the proposed work to negative variances. From this analysis we consider that United Energy's proposed demand-driven expenditure is higher than it is likely to incur.

Focus projects

691. The AER asked us to assess four Focus Projects:

- Doncaster supply area,
- Malvern supply area,
- Keysborough supply area, and
- Mornington supply area.

692. For three of the four projects we consider that United Energy has selected the appropriate option. For Keysborough supply area we consider that an alternative option is preferrable.

693. We undertook sensitivity analyses which lead us to conclude that, in all four projects, there is an opportunity to prudently defer some or all of the proposed scope of work beyond the next RCP.

Remainder of Subtransmission Substations, Switching Stations, Zone Substations

694. The remaining capex in this Group is directed towards installation of nine load shedding schemes. Based on the information provided, the work at five of the nine substations appear to satisfy the Network Planning Guidelines and it is reasonable to assume that the other four schemes are likewise justified. As United Energy has recent experience in installing these schemes, we consider the cost is likely to be reasonable.

Subtransmisison lines

695. Only four demand-driven subtransmission line projects are planned for the next RCP. United Energy has provided little information in support of the proposed capex. Accordingly, we consider that United Energy has not sufficiently demonstrated that its proposed expenditure is prudent and efficient.

HV Feeders

696. In addition to the feeder projects associated with Focus Projects, United Energy has provided a business case covering the eight largest feeder projects. The remaining expenditure covers 24 other projects.

697. United Energy did not provide economic analyses or any form of sensitivity analyses to demonstrate the robustness of the proposed eight largest feeder projects. We consider that sensitivity analyses would show that there is a reasonable likelihood of being able to prudently defer some of the planned work beyond the next RCP.

698. Approximately half of the other 24 feeder augmentation projects are scheduled to commence in the final year of the next RCP. Even a small reduction in peak demand over the next five years is likely to provide the opportunity to prudently defer some of the expenditure beyond the next RCP.

Distribution substations and LV Feeders

699. The ongoing distribution substation (DSS) and LV circuits program includes capex offsets from the assumed impact of United Energy's Summer saver program. Despite this offset, the overall forecast capex in the next RCP is 15% higher than in the current RCP. We consider that sensitivity analyses indicate that the forecast expenditure for the DSS program is likely to be biased towards overstating the capex requirement in the next RCP.

700. United Energy has based its forecast capex for the LV feeder program on the historical average, which we consider to be a reasonable approach. We consider the capex forecast to be reasonable.

Other assets

701. We consider that United Energy has provided sufficient evidence to demonstrate that its proposed expenditure for the Telstra 3G retirement project and the Spectrum changeover project is likely to be prudent and efficient.

702. United Energy has provided insufficient evidence to demonstrate that the remainder of the proposed expenditure is prudent and efficient.

6 REVIEW OF PROPOSED SOLAR ENABLEMENT EXPENDITURE

In this section, we review United Energy's proposed expenditure for solar enablement, and which includes expenditure for 533 LV augmentations and a proposed opex step change for an enhanced compliance program and for LV transformer tapping.

We consider that United Energy has a reasonable solar enablement strategy involving a combination of compliance measures, transformer tapping and utilising a DVMS that United Energy already has in place, before undertaking LV augmentations where these are warranted on a case-by-case basis. However, we have significant concerns with the way in which United Energy has developed the forecast of its expenditure requirements.

The large majority of the proposed expenditure is capital expenditure for the LV augmentations. In seeking to justify these augmentations, we consider that United Energy 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 estimate that the majority of the claimed benefits could be achieved from a much smaller program.

We also consider that United Energy's assumed unit cost for transformer tapping is unreasonably high, as is its proposed compliance program step change.

6.1 Introduction

703. United Energy 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 United Energy proposes is for capex to augment the network; however, United Energy also proposes to increase opex on several measures that can mitigate the need for, or extent of, such network augmentation.

6.2 United Energy's proposed Solar Enablement program

6.2.1 United Energy's proposed augex

704. United Energy proposes incurring $42.4m[219] over the next RCP for a network augmentation program to enable increased PV to be deployed. This would involve upgrading the network at 533 LV locations, and includes a combination of LV augmentation alone, new transformers and some LV augmentation in conjunction with new transformers.

[219] Excluding real cost escalation

Table 6.1: Solar Enablement project – Augex component - $m, real 2021

Project Title	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Solar Enablement Initiative	7.5	9.6	8.7	9.2	7.5	42.4
Total	**7.5**	**9.6**	**8.7**	**9.2**	**7.5**	**42.4**

Source: EMCa analysis of United Energy MOD 6.01 (excludes real cost escalation)

6.2.2 United Energy's proposed operational initiatives and associated opex step changes

705. In addition, United Energy proposes an opex step change totalling $4.2m, with the majority of this to allow for an increased program of manually tapping distribution transformers to help to maintain LV distribution voltages within Code[220] limits and a component that is proposed to institute a compliance program.

Table 6.2: Solar Enablement Opex Step Change - $m, real 2021

Project Title	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Solar Enablement Initiative	0.9	0.8	0.8	0.8	0.8	4.2
Total	**0.9**	**0.8**	**0.8**	**0.8**	**0.8**	**4.2**

Source: EMCa analysis of 'United Energy - RIN001 - Workbook 1 - Reg Determination - 31 January 2020' (includes real cost escalation)

United Energy's transformer tapping program

706. United Energy 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. United Energy's modelling of the impact of this initiative is limited by needing to ensure that the LV voltage on a particular section of the network stays within the minimum voltage threshold (as defined in the Code). In other words, in responding to high voltages which may occur at some times of the day/week, United Energy has also sought to ensure that it does not cause undervoltage compliance issues. United Energy has determined that some transformers are able to be tapped multiple times and this has been allowed for in its model. United Energy has based the cost of tapping on a rounded equivalent of the average cost per site tapped in 2019.[221]

United Energy's proposed monitoring and compliance program

707. PV inverter system installers are required to ensure that inverters are set to comply with the requirements of AS4777 and United Energy'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.

708. United Energy 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.*'[222] United Energy has forecast the monitoring and compliance cost based on the cost to implement remote monitoring and a 5% rate of non-compliance.

[220] Victorian Electricity Distribution Code, Version 9A, clause 4.2.2 (Table 2, Standard nominal voltage variations)

[221] Response to IR044 – Solar Enablement, page 1

[222] UE BUS 6.06 – Solar enablement, page 34

6.2.3 Supporting material that United Energy provided

709. In its submission, United Energy has provided information, evidence, and contextual information regarding its proposed solar program. We briefly summarise the main content of these documents below.

Material provided with United Energy's regulatory submission

1. *United Energy's business case (UE BUS 6.06) and associated model (UE MOD 6.02)*

In its business case United Energy 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 United Energy's stakeholder engagement process, how this has shaped United Energy's proposed program and mechanisms for managing constraints.

United Energy'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' (UE ATT196).*

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 United Energy's cost benefit assessment.

4. *Other Supporting material provided with Regulatory Submission*

United Energy provided a range of attachments (refer to ATT145, ATT146, ATT147, ATT148, ATT149, ATT150). 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.

710. Subsequent to its submission, United Energy has provided further information and claims regarding its proposed program. We summarise these below.

Information and claims subsequent to United Energy's regulatory submission

United Energy provided additional information in its presentation to EMCa, with 9 PowerPoint pages devoted to the solar enablement program. United Energy also provided responses to three Information Requests as follows:

1. *IR017: 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 United Energy had taken account of the future impact of batteries and electric vehicles. United Energy also provided information showing its assessment of the benefits year-by-year for each proposed LV upgrade.*
2. *IR027: The IR sought the NEIR solar forecast report, however United Energy explained that NIEIR did not provide a report. The response provides information on the claimed basis for United Energy's assumptions regarding augmentation and tapping costs, however it refers to the business case already provided for the quantitative information. The response explains how United Energy has taken transformer tapping into account in assessing the need for augmentation, explains that it had not undertaken sensitivity analyses and describes steps being taken to mitigate inverter settings non-compliance.*
3. *IR044: United Energy provided a range of information under this heading, including:*
    a. *Derivation of its average tapping cost (of $1,500);*[223]
    b. *A response on compliance drivers, in which United Energy 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, with a forecast of 23% by the end of the RCP, which aligns with its business case.*

223 From United Energy's response to IR044 – Solar Enablement (including table 1 on page 1). $nominal in 2019.

6.2.4 Main elements of United Energy's justification for its proposed program

Distributed solar penetration and implications for LV distribution networks

711. 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.

712. 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. However, in its Business Case, United Energy states that while it considers that '…*any approach to enabling solar should contribute towards rather than detract from our Code obligations*,' United Energy states that its primary intended outcome is not targeted at Code compliance.[224]

713. United Energy'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.

United Energy's current state and forecasts

714. United Energy 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.

715. United Energy currently has 11% solar penetration[225] and overall the network is not currently experiencing significant constraints to solar export quantities. Based on United Energy's modelling, it still expects that by 2021/22 only a relatively small number of customers' inverters on 4.3% of its LV transformers, may experience tripping under certain circumstances sufficient to warrant consideration of LV augmentation.[226] United Energy expects solar penetration to increase to 23% by 2025[227] 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.

United Energy's analytical approach to determining the future incidence of export limitation issues[228]

716. Using capability derived from its smart grid / smart metering program, United Energy 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.[229]

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224 UE BUS 6.06 – Solar enablement, page 14

225 UE BUS 6.06, page 9. Measured as a percentage of total customer numbers

226 United Energy's analysis presents export constraint information on 533 out of its 12,500 transformers, which is 4.3%. We observe minimal constraint over the RCP on the majority even of this 'worst' subset of 533

227 Ibid, page 9. United Energy attributes this forecast to advice from NIEIR

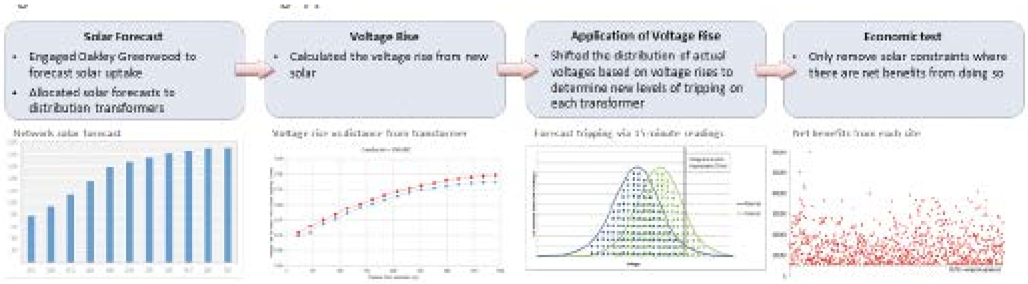
228 Ibid, page 6

229 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

717. United Energy states that it has sought to find the least cost way to address a constraint by '…applying smart settings to customers' inverters, 'tapping' down distribution transformer (transformer) voltages and undertaking efficient network investment.'[230]

718. Figure 6.1 illustrates the process that United Energy has followed.

Figure 6.1: United Energy's modelling approach to forecasting required capex for solar enablement LV upgrades



Source: United Energy BUS 6.06 Solar enablement – Jan2020, Figure 3, p.6

719. United Energy has proposed LV network capex for the sum of LV upgrades (largely transformers) that individually pass its economic test (i.e., the upgrade project has a positive NPV).

United Energy's economic model

720. United Energy 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, United Energy has forecast the amounts of energy (MWh) for which exports might be curtailed from inverters tripping due to overvoltage;[231]
- United Energy 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 United Energy from a study undertaken by Jacobs, and comprises Jacob's assessment of the '*reduction in total generation costs (fuel and operating and maintenance costs) and the value of carbon abatement.*'[232]
- United Energy applies a unit cost estimate of $76,375 (in $2019) per LV augmentation project. This is derived from an unweighted arithmetic average of four types of upgrades, which United Energy individually costs at between $42,800 and $138,100 per augmentation (in $2019).
- From this, United Energy calculates the PV of the benefits of undertaking each potential LV upgrade over a 30 year period, using a discount rate of 2.75%. Although not explicit in its model, we understand that it is from this analysis that United Energy has forecast the need for the proposed 533 upgrades, being all such upgrades for which United Energy determines a positive NPV from this modelling.

721. United Energy bases its proposed solar enablement upgrade capex on undertaking these 533 LV upgrades within the next RCP.

[230] UE BUS 6.06 – Solar enablement, page 6

[231] We understand that this modelling was similar to that undertaken by Powercor and CitiPower – however unlike Powercor and CitiPower, United Energy did not provide the information in its model to demonstrate this

[232] UE ATT054 – Jacobs – Market benefits for solar enablement (15 August 2019)

6.3 EMCa assessment

6.3.1 Topics considered in our review

722. In our review, we have focused largely on United Energy's claimed economic benefits. Of the substantial amount of material that United Energy has provided, we have accepted the following either as reasonable for the purpose of advising on this component of United Energy's expenditure allowance, or we have considered it to be not directly relevant to the assessment:

- **Stakeholder engagement:** We acknowledge United Energy's stakeholder engagement process and the feedback that United Energy obtained through this process. Our observation is that United Energy 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 United Energy's analysis, we consider it likely that some of the other options that it canvassed may also be adopted and may act to mitigate the need for the proposed program.
- **PV uptake assumptions:** We have been unable to investigate these. United Energy has referred to the National Institute of Economic and Industry Research (NIEIR) as the source of its advice, but has been unable to provide a report on this forecast. Whilst this forecast is highly relevant to United Energy's forecast, we have necessarily based our review on other factors, which we describe in section 6.3.3.
- **Market benefit value:** We have not investigated this beyond the scope of the supporting document that United Energy provided.[233] This appears to be a reasonable and well-founded source for the value that United Energy has adopted. In other information that United Energy has provided, it appears to contradict the advice that it was provided for this value. For example, United Energy 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*.'[234] While we have not analysed evidence other than what United Energy has provided and have therefore not analysed the alternative values referred to, we do not see any indication in the Jacob's report that would position its recommended value as a conservative estimate.
- **Modelling of voltage impacts of solar:** We have not investigated this beyond the supporting description that United Energy provides.[235] We consider that the description of load flow modelling in association with the forecast solar uptake rate and United Energy's AMI data on its network at the individual customer level, is likely to have provided a reasonable basis for such estimation.

723. We have noted United Energy'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*.'[236] Further, under its Distribution Licence, United Energy has an obligation to offer to connect solar[237] and therefore must manage resulting voltage excursions within the parameters of the Code.

724. 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 United Energy has used to support its augmentation program;
2. The relationship that United Energy has claimed between the 30-year economic assessment horizon and the economic life used for depreciating LV network assets (including transformers);

233 UE ATT055: Report by Jacobs

234 UE response to IR044, page 9

235 For example, in section B.1.3 of its business case (UE BUS 6.06)

236 Response to UE IR044, page 1. This in turn references section 4.1 of version 11 of the Code

237 Ibid, page 2

3. Factors that could lead to the proposed augmentation program being overstated; and
4. United Energy's assessment of the appropriate timing of each proposed augmentation, including its justification for this taking place within the current RCP.

725. In our assessment of United Energy's proposed opex step change, we consider United Energy's estimated volume of required tapping and its assumed unit cost for this.

6.3.2 Guiding principles for our review

726. 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:** It is unclear from United Energy's model how many solar customers it is typically seeking to be able to accommodate on each LV network. However, if we were to conservatively assume in the order of 50 to 100 customers per network, then at United Energy's proposed LV augmentation cost averaging around $76,000 for each such upgrade, this represents a network upgrade investment of around $700 to $1,500 per customer. This is not an insubstantial amount, especially when compared with the 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.

727. We consider that principles such as these will serve to guide United Energy towards the most appropriate actions being taken to accommodate distributed solar and to enable customers to achieve the benefits of their own investments.

6.3.3 Review of United Energy's justification for proposed augex

Analysis period

United Energy has not adequately considered the uncertainty inherent in seeking to justify capex based on a 30-year analysis of assumed PV export benefits

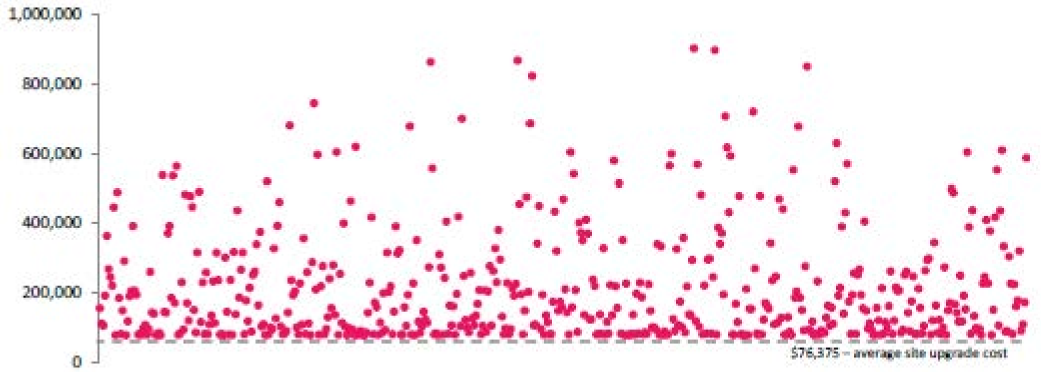
728. Whilst we consider that modelling of both tripped export volumes and individual upgrade economics at the level of granularity that United Energy has undertaken is a useful approach, we have significant concerns with aspects of this modelling and therefore with the conclusions that United Energy has drawn from it.

729. Our primary concern is with United Energy seeking to justify the proposed expenditure based on modelling over a period of 30 years, and with its assumption that the benefits will be maintained over this period.[238] 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 United Energy has assumed to 2051/52.

730. It is evident from United Energy's representation of the NPVs of the 533 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, as can be seen in Figure 6.2 below.

[238] United Energy appears to model these benefits specifically for 14 years, but then assumes that those benefits continue at the modelled year 14 level for a further 16 years. (See tab 'NPV of benefits' on United Energy's updated version of UE MOD 6.02, provided as response to IR017)

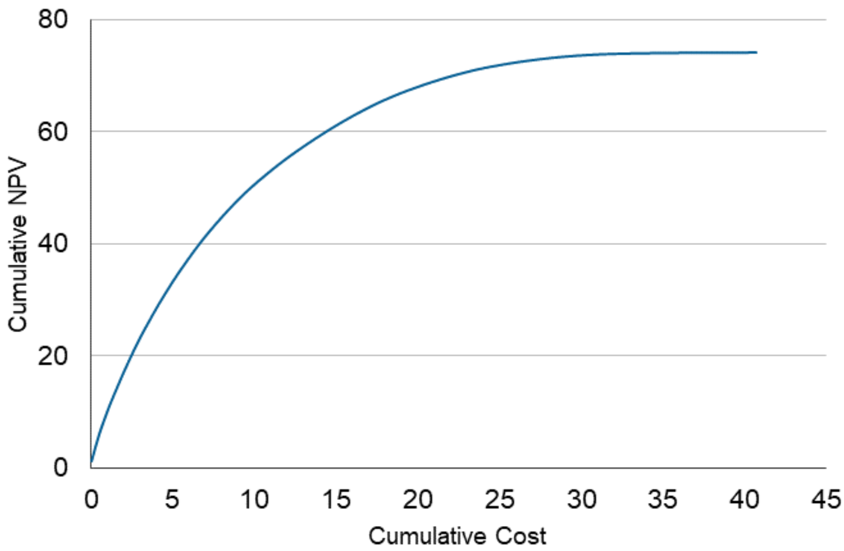
Figure 6.2: United Energy's representation of the NPV of its proposed 533 LV augmentations



Source: United Energy BUS 6.06, Figure 11 (The Y axis is the PV of benefits for each proposed upgrade)

731. In Figure 6.3 below, we show the cumulative NPV of each of the LV augmentations that United Energy has proposed, ordered with the highest NPV augmentations first, based on United Energy's analysis. There is a clearly decreasing marginal benefit. Our analysis indicates that 92% of the aggregate NPV of the program would be achieved from a program only half the size of that proposed.

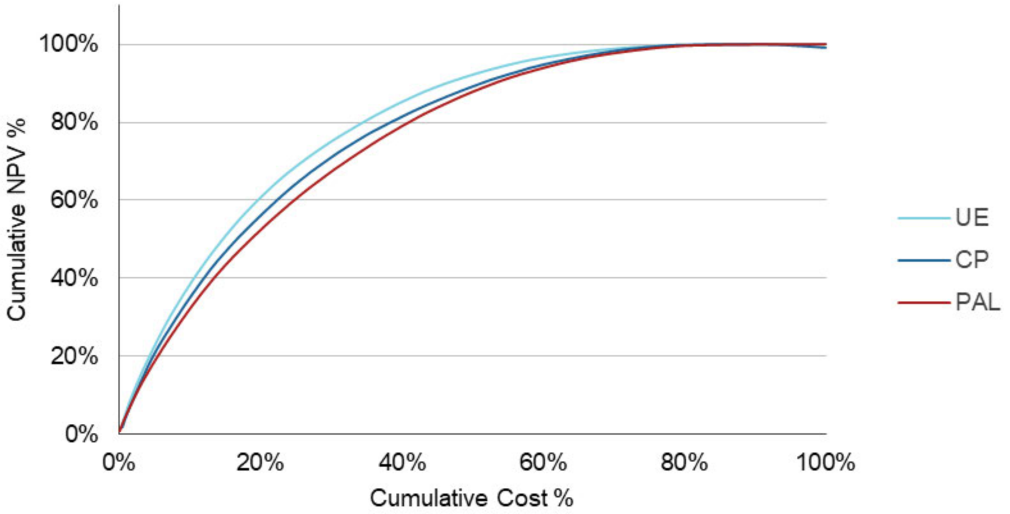
Figure 6.3: Cumulative NPV of United Energy's proposed 533 LV upgrades - $m, 2020



Source: EMCa analysis from UE MOD 6.02

732. United Energy has not provided sufficient information to be able to run sensitivity analysis on scenarios involving analysis over different period. We compared a normalised version of United Energy's ordered cumulative NPV with the equivalent curves for Powercor and CitiPower. We find that the three businesses are relatively similar, with United Energy being closer to CitiPower.

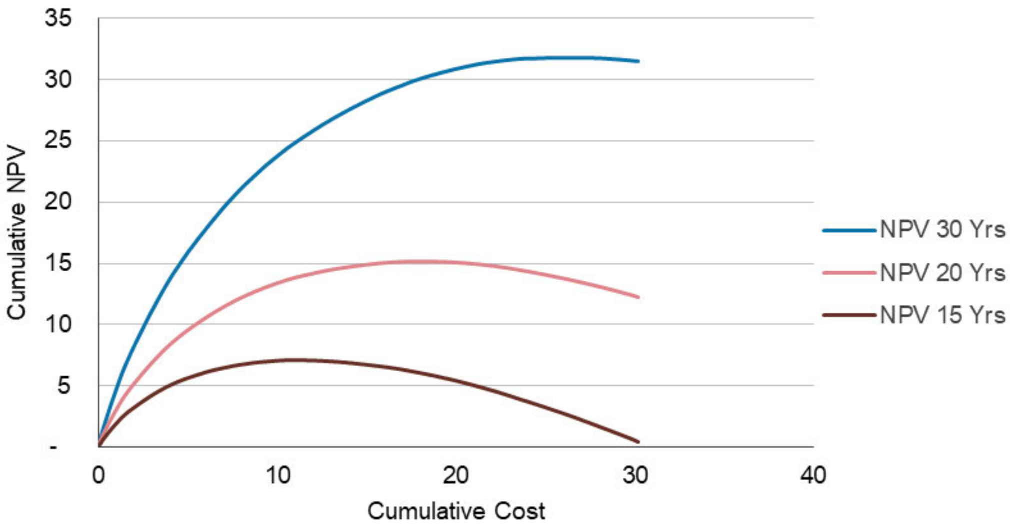
Figure 6.4: Normalised cumulative NPV of proposed augex upgrades – comparison between United Energy, Powercor and CitiPower



Source: EMCa analysis from UE MOD 6.02 and equivalent models for Powercor and CitiPower

733. To provide an indication of sensitivity, we show in Figure 6.5 below an equivalent sensitivity analysis for CitiPower, where we tested for sensitivity of CitiPower's result to the time period considered. The lower two lines in Figure 6.5 show the implication of adopting 20-year and 15-year horizons respectively, for the NPV 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. In aggregate, if all of the upgrades were done, the NPV of the program would be effectively zero.

Figure 6.5: Cumulative NPV of the proposed 319 LV augmentations proposed by CitiPower, over different analysis horizons - $millions



Source: EMCa analysis from CitiPower MOD 6.02

734. 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. We observe that United Energy adopts a 20-year horizon in its economic analysis to justify augex for general load growth, and which would typically be seen as more amenable to forecasting. 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 other measures being introduced within that timeframe, including those that United Energy canvassed, such as changes to tariff structures and possible further compliance requirements.

735. It is impossible to build such unknowns 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 United Energy has proposed.

We refute United Energy's claim that use of a shorter NPV analysis period would imply a position that use of solar would decrease

736. United Energy has provided further information in its IR responses, relevant to the question of the NPV time-period and uncertainty. We address these points below.

737. United Energy 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.'[239]

738. We refute this statement – it is not axiomatic that adopting an NPV analysis period shorter than United Energy has proposed implies a view that the use of solar will decrease. We describe above a number of reasons to explain why it would be reasonable to adopt a shorter analysis period than United Energy has adopted. None of these rely on an assumption of decreased solar.

We do not accept United Energy's argument that the NPV analysis period must equal the depreciation life of the relevant asset

739. 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. Whilst 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.

740. United Energy 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.'[240] United Energy has then extended this argument to suggest that a shortened depreciation period would lead to higher network prices resulting from its SE program.[241]

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239 Response to United Energy IR044 – Solar Enablement, 3 July 2020, response to question 7

240 Ibid, page 11

241 Ibid, page 12

741. In its response, United Energy 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

(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.

742. We consider that United Energy 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.

743. 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, but the analysis period for which it is reasonable to consider benefits to justify the LV augmentation investment, 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.

744. 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 something of an ambit claim for United Energy 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 United Energy's claim that sensitivity analysis is unnecessary

745. In response to an IR, United Energy states that it has '…not undertaken formal sensitivity analysis…'. United Energy 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.'[242] This seems to us 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 this cost - just by inspection of United Energy'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 say a 10% lower NPV threshold, such as would result from a higher unit cost per LV upgrade.

746. Particularly with a forecast over 30 years, all assumptions and all aspects of United Energy'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. United Energy's case is weakened by the lack of such sensitivity analysis, and by its claims that such analysis is unnecessary.

United Energy has not justified its claim that its assumptions are conservative

747. United Energy claims that *'(t)he value of DER we have used is very* conservative'.[243] Our assessment of this claim is as follows:

242 United Energy's response to IR027, question 3, page 2

243 United Energy response to IR044, question 7.

- While United Energy asserts that it considers that the value of DER that it has used is conservative, this value is as recommended by United Energy's advisor – Jacobs. The Jacobs' report does not position this as a 'conservative' value, and it appears disingenuous for United Energy to suggest that its advisor has not provided it with a reasonable estimate, especially given that United Energy has used it as such;
- United Energy states that '…*varying the value of DER in our model would only serve to expand the program….*'[244]. United Energy seems to have taken the position that it would not undertake a symmetrical sensitivity analysis;
- United Energy has assumed 100% compliance with new converter settings. This appears to us a reasonable assumption to make; it should not be for United Energy to assume responsibility for undertaking augmentation investment, which brings costs to all consumers, in order to redress non-compliance by another party; and
- United Energy states that it has 'not valued the additional customer benefits that can be derived from solar including retail and wholesale arbitrage opportunities, wholesale market support, transmission and distribution congestion management.'[245] While these are general claimed benefits of solar, their link to United Energy's proposed LV augmentations is tenuous. United Energy'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, United Energy would need to be able to demonstrate a counterfactual 'lost opportunity' and the extent to which it is remedied by its proposed program.

748. Against these points, we consider that there are other aspects of United Energy'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 (for example) of PV uptake, etc.

749. 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 United Energy's claim that there is not a material risk of 'stranded' investment

750. If the LV augex investments are made as proposed by United Energy, many of these have only a marginal net benefit on a 30-year analysis basis with United Energy's assumptions. For the reasons stated above, we consider that there is a material risk that the assumed 30-year benefits could be less than United Energy 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.

751. United Energy 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'.[246]

752. As we have shown in Figure 6.5, when we consider shorter analysis periods, it appears by analogy with the modelling undertaking for CitiPower that a large number of the proposed augmentations are likely to have a negative NPV. We also do not accept the proposition that uncertainty is accounted for by United Energy 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.

753. 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,

[244] United Energy response to IR044, page 10

[245] United Energy response to IR044, page 11

[246] Ibid, page 9

then we consider that there is a material risk of those augmentation investments turning out to have not been required.

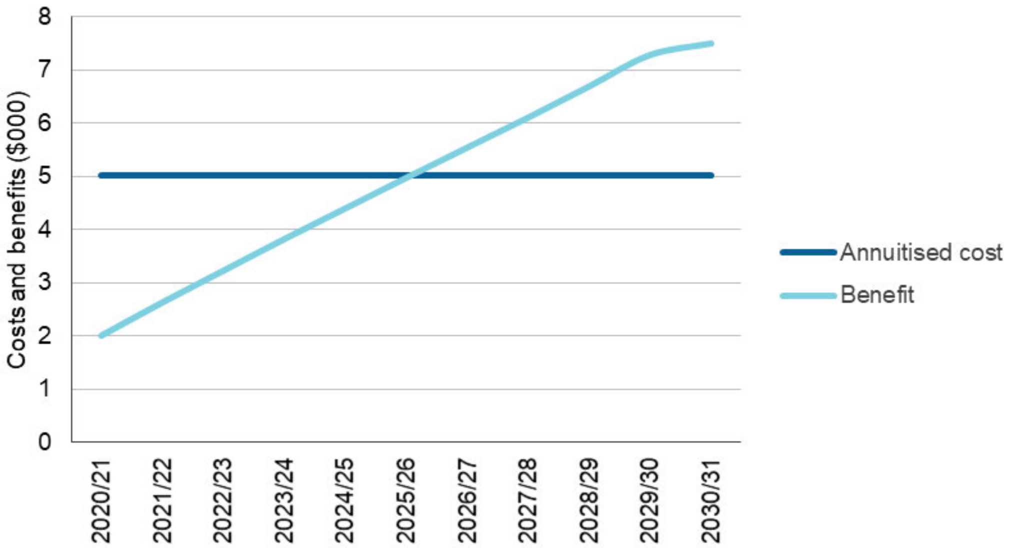
Time profile and justification within the next RCP

United Energy has misapplied analysis to forecast the time profile of its expenditure

754. It is unclear from the model and information provided how United Energy has sought to determine a time-profile for its proposed augmentation expenditure or to confirm the extent of expenditure that is justified in the next RCP. The appropriate 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 United Energy has applied this approach are illustrated in Figure 5.5 and Figure 5.9 and for other augex projects in that section.

755. In Figure 6.6 we show an example of this methodology applied to a specific LV transformer from United Energy's solar enablement analysis. In this case, it indicates that an upgrade would be warranted in 2024/25 based on United Energy's benefit assumptions including its forecast PV uptake rate for customers connected to that transformer.

Figure 6.6: Annuitised cost and modelled benefits for one of United Energy's proposed transformer upgrades[247]



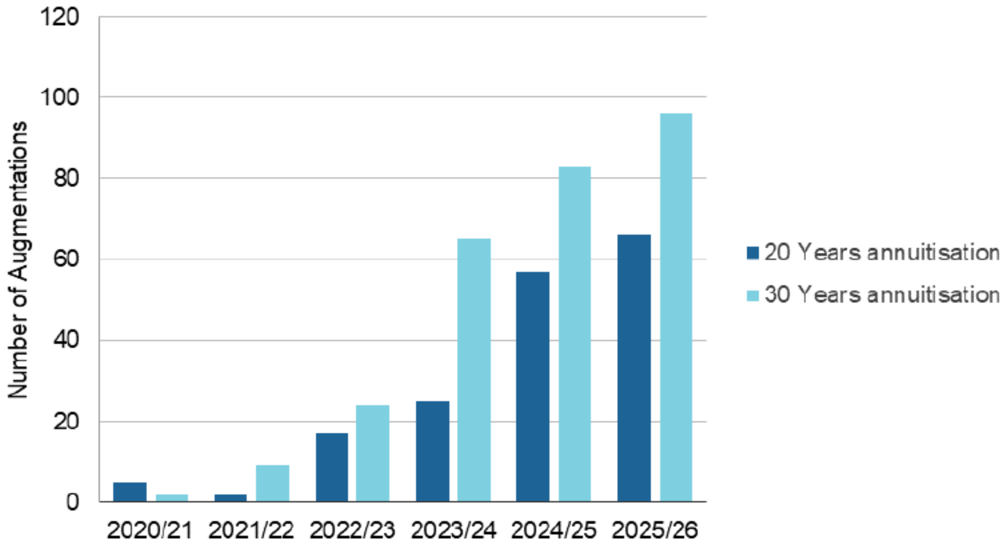
Source: EMCa analysis from the updated version of UE MOD 6.02 that United Energy provided in its response to IR017. The upgrade cost in this example is annuitized over 20 years.

756. When we apply this method to all 533 of United Energy's proposed augmentations, we find a profile of augmentations as shown in Figure 6.7. We have undertaken this analysis with augmentation costs annuitised over 30 years, as per United Energy's assumptions, and an alternative forecast in which the cost is annuitised over 20 years.

757. A very small number of augmentations are indicated for the early years, which is as we would expect given United Energy's very low current PV penetration. If the uptake rate and other benefit assumptions are as United Energy has forecast, our analysis suggests an increasing trend of augmentations over the period. However, our analysis also shows that under United Energy's cost and benefit assumptions, only 277 of its proposed 533 augmentations would be viable. If a 20-year annuitisation period is adopted (consistent with United Energy's non-DER augex justifications), then only 167 augmentations would be viable within the next RCP.

247 The modelled transformer in this example is "DARIUS ROMME"

Figure 6.7: Augmentation profile indicated by identifying year when benefits exceed costs



Source: EMCa analysis from CP MOD 6.02

758. The table below shows the time profile of expenditure that results from this timing analysis.

Table 6.3: Implied annual expenditure profile based on indicated timing for each transformer - $m, 2020

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
30 Years annuitisation	0.7	1.8	5.0	6.3	7.3	21.2
20 Years annuitisation	0.2	1.3	1.9	4.4	5.0	12.8

Source: EMCa analysis from CP MOD 6.02

759. 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 of assumptions and uncertainties as described in the preceding subsections. However, when compared with United Energy's proposed expenditure (in 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 United Energy 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 United Energy's package of solar enablement measures

760. In the context of significant uncertainty, we observe that even from United Energy's modelling, 92% 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. The rapid fall-off in incremental benefit with increasing scale of the proposed project, can be seen in Figure 6.3 and Figure 6.5. It is also evident in the large number of projects with an NPV close to the X axis in United Energy's own diagram in Figure 6.2.

761. We also observe the current PV penetration rate of 11% on the United Energy network that is relatively low when compared (for example) to a rate of around 30% in Queensland. Victoria also has a lower solar insolation rate than Queensland. United Energy's forecast of a 23% penetration by 2025/26 would seem to provide the opportunity for United Energy to

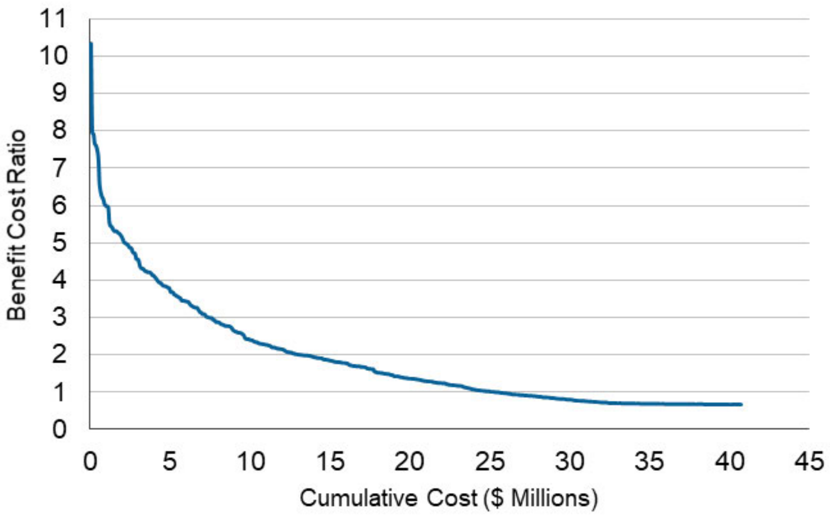
compare what it proposes with what Queensland DNSPs have already done to efficiently enable increased solar penetration on their networks.

762. United Energy'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 United Energy will find that considerably less LV augmentation expenditure is justified.

A program of around 175 to 250 upgrades would appear to provide a justifiable degree of solar enablement benefit, though with less than 170 upgrades within the next RCP

763. As an indication, we have re-expressed the United Energy cost benefit analysis in terms of Benefit/Cost (B/C) ratio, and 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 of around 1.5 to 2.0 and to allow expenditure sufficient for projects that exceed this threshold.

Figure 6.8: Ranked Benefit/Cost ratio of 533 proposed LV upgrades (20-year analysis)



Source: EMCa analysis from a combination of information in UE MOD 6.02, with the implications of a 20-year NPV derived from EMCa analysis of CP MOD 6.02

764. This would imply reasonable justification for a program involving around 30% to 47% of the augex that United Energy has proposed. This would be equivalent to around 175 to 250 LV upgrades with an augex investment of around $13m to $19m. However, while this may be a viable number of upgrades to undertake (based on current assumptions), this does not mean that this amount is justified within the next period. As we have shown in the preceding analysis, due to timing considerations, a justifiable amount within the next RCP is more likely to be in the order of $13m. This would correspond to less than 170 LV augmentations within the next RCP.

6.3.5 Review of United Energy'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 United Energy's LV network

765. Whilst United Energy reports that 75% of its customers support network investment and 'modernising' the grid with new technologies, it also reports that:[248]

[248] United Energy Regulatory Proposal, p89

'our residential customers are generally satisfied with our existing reliability and power quality levels…'

766. While there may be localised pockets with voltage-related issues, there does not appear to be widespread dissatisfaction with power quality.

Tapping program

United Energy's strategy of exploiting the benefits of tapping before applying network solutions is appropriate

767. 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 United Energy 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 United Energy's proposed strategy of employing manual tapping of distribution transformers

United Energy's estimated volume of tapping is likely to be reasonable

768. United Energy's modelling of the opportunity for voltage profile adjustment using tap changing results in a forecast of 2,111 manual tap changes in the next RCP, with a relatively flat profile of over 400 tap changes each year.[249]

769. This profile is counterintuitive given that we would expect voltage rise issues to increase over time, with increasing PV penetration levels. However, we understand that United Energy's model is based on identifying localised constraints.

770. 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. United Energy provided information that it undertook 2,194 tap changes in the 5 years 2015 to 2019,[250] so the proposed volume in the next RCP would be similar to the volume in that historical period.

771. Given that we consider United Energy'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 also likely to be a reasonable estimate.

United Energy's unit cost for tapping appears to be relatively high

772. United Energy has based its unit cost on analysis of its tapping costs in 2019. It is appropriate for United Energy to apply recent revealed costs if the revealed costs are demonstrably efficient. However, at over $1,500 per unit, United Energy's unit cost is significantly higher than AusNet Services at $865/unit.[251] We are not aware of any reasons to explain the significantly higher unit cost at United Energy.

773. In our view, United Energy'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

United Energy's monitoring and compliance program as proposed is not a justified step change

774. United Energy 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, United Energy is

249 UE MOD 6.02

250 United response to IR 044

251 AusNet Services response to IR049

within its rights to require the customer to rectify the non-compliance. United Energy proposes to spend $235k over the next RCP to establish and maintain a monitoring program, plus a further $407k over the next RCP to address instances of non-compliance.[252]

775. 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. However, we are not convinced that United Energy:

- has explored cost effective options for proactively ensuring installers to apply the correct inverter settings;
- has explored cost effective options for identifying and addressing non-compliances; and
- requires a separate program that is incremental to its business-as-usual Power Quality program for reactive rectification of PQ issues in response to customer complaints.

Links to United Energy's proposed ICT initiatives

We have considered the link to the Digital Network initiative in our ICT assessment

776. United Energy has noted linkages and dependencies between its Digital Network initiative[253] and its Solar Enablement program. Specifically:

- in its modelling of constraints to PV export, United Energy assumes that solar connections will be balanced across phases; and
- United Energy 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).[254]

777. We have considered these linkages in our assessment of United Energy's ICT expenditure forecast.

6.4 Implications to United Energy's proposed solar enablement augex and associated opex step change

778. Based on the information available to us at the time of preparing this report, we consider that United Energy has not sufficiently demonstrated that the proposed expenditure forecast for its solar enablement program is prudent and efficient.

779. As described below, we have identified a number of issues associated with the capital and operating expenditure proposed by United Energy to economically reduce the constraints on solar export in the next RCP.

780. We consider that:

- United Energy 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 therefore to (ii) overstate the reasonably justified extent of network augmentations;
- United Energy has not correctly assessed the time profile for the LV upgrades that it has proposed. We find that a corrected methodology, when applied to the benefits stream that United Energy has forecast, shows that less than half of the proposed expenditure is justified within the next RCP, with the majority of that towards the end of the period.
- United Energy has appropriately identified transformer tapping as a relatively inexpensive initiative to mitigate over-voltages prior to network augmentation – however,

252 UE BUS 6.06, Table 9, page 36. Note that these figures are in $2019

253 The business case for Digital Networks is included in CP's Information and Communication Technology (ICT) category

254 CP BUS 6.02 Solar enablement, page 17

we are not satisfied that the unit cost of proposed tap changes has been adequately justified; and

- United Energy has appropriately identified rectification of 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 United Energy's expense is the most cost effective approach.

7 REVIEW OF PROPOSED ICT EXPENDITURE

In this section, we present our assessment of United Energy's forecast ICT capex together with aspects of proposed opex step changes that are related to the proposed capex forecast and which the AER has asked us to review.

Our assessment of the AER focus projects leads us to conclude that, in each case, the proposed expenditure is overstated compared with the level of expenditure that a prudent and efficient operator would be expected to incur.

For Non-recurrent projects, we found issues with the claimed benefits based on what we consider to be overstated assumptions, particularly given the uncertainty of the duration in which the benefits will be realised. We undertook sensitivity analyses with what we consider to be more reasonable assumptions. We conclude that there are several cases in which the proposed expenditure is unlikely to satisfy the capex criteria.

For Recurrent (replacement/upgrade) projects, we found some cases in which United Energy has provided insufficient justification for the proposed level of expenditure.

We consider that the 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

781. We reviewed the information provided by United Energy to support its proposed ICT forecast, including the business cases. Our focus is to: (i) ascertain the extent to which the issues identified in our assessment of United Energy's expenditure governance, management and ICT forecasting methodologies are evident at the project/activity level; and (ii) to assess the extent to which the forecast expenditure is likely to meet the NER criteria.

782. The AER has identified a number of 'Focus' projects to us. Accordingly, we have included these in our assessment of the proposed ICT forecast within the relevant category of expenditure, as denoted below:

- ICT infrastructure cloud migration ($22.8m capex and $4.5m opex step change);
- Customer enablement program ($13.3m capex);
- SAP S/4 HANA ($25.7m capex);
- Digital Network ($19.4m);
- Intelligent Engineering ($5.4m); and
- Network Management Systems ($24.9m).

783. Some projects are supported by business cases that cover the total expenditure applicable to CitiPower, Powercor and United Energy – with apportionment of the total cost between the three entities. We identify these projects in our reviews in sections 7.4 and 7.5.

7.2 Summary of United Energy's proposed ICT expenditure

7.2.1 Overview

784. United Energy has proposed $194.3m in total ICT capex for the next RCP, at an average annual expenditure of $38.9m. In the table below, we show ICT capex by RIN Category including real cost escalation.

Table 7.1: United Energy's ICT expenditure by RIN category- $m, real 2021

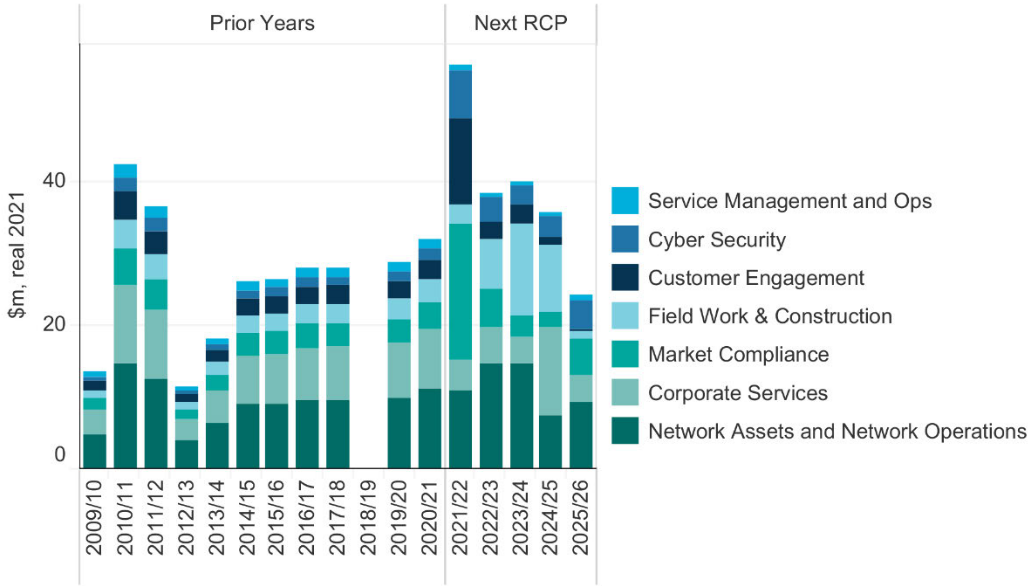
	Next RCP					
Category	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**Total**
Corporate Services	4.0	5.2	3.8	12.3	3.6	28.9
Customer Engagement	12.1	2.3	2.6	0.9	0.2	18.1
Cyber Security	6.7	3.5	2.6	2.8	3.9	19.4
Field Work & Construction	2.7	7.1	12.8	9.4	1.3	33.1
Market Compliance	19.0	5.2	2.9	2.2	5.1	34.4
Network Assets and Network Operations	11.0	14.6	14.6	7.5	9.4	57.1
Service Management and Ops	0.8	0.5	0.5	0.6	0.8	3.3
Total	**56.3**	**38.4**	**39.8**	**35.6**	**24.1**	**194.3**

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

7.2.2 ICT capex trend

785. 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. All expenditure has been inflated to Real 2021 dollars and forecast expenditure includes United Energy's proposed real cost escalation.

Figure 7.1: United Energy's historical and forecast ICT capital expenditure - $m, real 2021



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

7.2.3 Observations from ICT capex trend

786. The proposed ICT capex for the next RCP is an increase from the historical trend, with short-term increases in several of the RIN categories. The largest increase is to the Market Compliance and Customer Engagement RIN categories at the commencement of the next RCP (i.e., in 2021/22).

7.2.4 ICT projects categorised as Recurrent / Non-recurrent

787. 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: United Energy's project-level expenditure allocated to recurrent and non-recurrent expenditure classifications - $m, real 2021

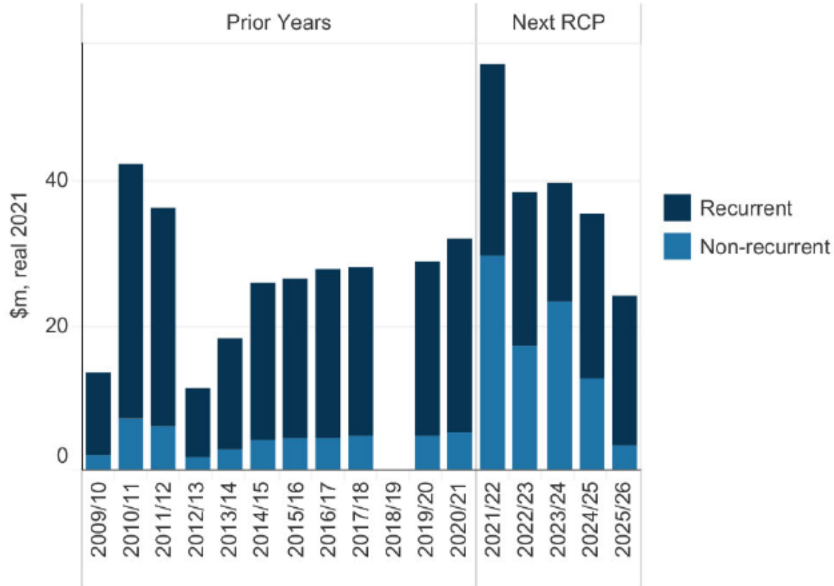
Project	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Recurrent	**26.3**	**20.6**	**15.6**	**21.4**	**19.3**	**103.2**
BI/BW	0.5	1.1	0.5	0.1	0.1	2.3
Customer Enablement		0.6				0.6
Cyber security	4.6	2.4	1.7	1.9	2.5	13.1
Device replacement	0.8	0.5	0.5	0.6	0.7	3.1
Enterprise Management Systems - Non-SAP	3.0	1.7	2.1	1.2	0.8	8.7
Facilities' security	0.1	0.6	0.7	3.2	0.1	4.7
General compliance	1.6	1.6	1.6	1.6	1.6	8.2
Infrastructure with Cloud migration	3.9	4.4	2.9	8.4	3.2	22.8
Market Systems	2.8	0.4	1.0	0.3	2.8	7.4
Network Management	5.0	5.2	4.0	4.2	6.4	24.9
SAP S/4HANA	0.9	1.5			0.7	3.1
Telephony	3.0	0.6	0.6		0.2	4.4
Non-recurrent	**29.2**	**16.6**	**22.4**	**12.1**	**3.1**	**83.4**
5 Minute Settlements	14.2	3.0	0.1	0.1	0.2	17.7
Customer Enablement	8.9	1.1	1.9	0.9		12.7
Cyber security	1.9	1.0	0.7	0.8	1.1	5.6
Digital network	4.1	6.5	5.6	1.3	1.8	19.4
Intelligent engineering		1.4	3.1	0.8		5.4
SAP S/4HANA		3.5	10.9	8.2		22.6
Total	**55.5**	**37.3**	**38.0**	**33.5**	**22.4**	**186.7**

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

7.2.5 ICT Capex trend by Recurrent/Non-Recurrent expenditure classification

788. 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, particularly 2021/22 which is driven by the 5-Minute Settlement compliance program. The reduced level of expenditure in 2025/26 results from the conclusion of most of the Non-recurrent projects.

Figure 7.2: Expenditure by Recurrent/Non-Recurrent - $m, real 2021



Source: EMCa analysis of 'United Energy - RIN001 - Workbook 1 - Reg Determination - 31 January 2020', 'United Energy - RIN008 - Workbook 8 - Historical FY CAT - 31 January 2020' (United Energy also provided historical data in Workbook 2. That data is in calendar years. While United Energy 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

789. United Energy has proposed an opex step change associated with its proposed ICT infrastructure cloud migration project. The corresponding expenditure is shown in the table below and includes real cost escalation.

Table 7.3: United Energy ICT – Related Opex step change - $m, real 2021

Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
IT Cloud Solutions	0.7	0.7	1.0	1.2	1.2	4.7
Total	0.7	0.7	1.0	1.2	1.2	4.7

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

7.3 Assessment of United Energy's ICT forecasting methods

7.3.1 Overview of United Energy's ICT forecasting methodology

790. United Energy describes its forecasting approach for ICT capex to '*only invest in ICT when there is a benefit to customers,*'[255] We summarise the approach described in its Regulatory Proposal[256] as:

- Assessing whether the existing ICT capabilities and services are no longer providing value to customers;
- Examining '*synergy opportunities'* to align ICT systems with CitiPower and Powercor;

[255] United Energy, Regulatory Proposal 2021-2026, page 120

[256] United Energy, Regulatory Proposal 2021-2026, pages 120-121

- Considering whether existing systems can withstand maturing and emerging cyber-security threats;
- Forecasting the efficient level of investment needed to retain the effectiveness and security of existing capabilities;
- Considering whether new technologies can address '*key business requirements'*; and
- Testing 'new projects with customers and other stakeholders to ensure we prioritised our investments in areas customers most value'.

791. To inform the selection of its ICT investments, United Energy advises that it:

- 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; [257] and
- Applied five IT assessment criteria to identify long term asset lifecycle management requirements for existing/legacy assets.[258]

792. United Energy's project delivery framework is described as comprising the common industry approach of initiation, scoping, design, and execution phases with approval gates as milestones.[259]

793. United Energy also describes that it has subjected the portfolio forecast to a top-down challenge:

> *'… we engaged PwC mid-way through developing our proposal to assess whether individual projects could be better prioritised or delivered more efficiently in order to optimise value for our customers;'* [260]
>
> *[We ensure] deliverability of [the] overall work program, considering project interdependencies and our IT operating model including our strategic partnerships and vendor support arrangements.'*[261]

794. United Energy describes its cost estimation methodology as follows:[262]

> *'Our forecast capital expenditure is estimated using a bottom up approach that leveraged information on historical projects relating to the target applications, and information on projects of similar nature and scope. We applied an external blended labour rate independently sourced from PwC.'*

795. The table below summarises the input parameters applied by United Energy in developing its cost estimates.

[257] United Energy, Regulatory Proposal 2021-2026, page 123

[258] United Energy ATT IR020 (b) – IT Assessment Criteria - CONFIDENTIAL

[259] United Energy, ATT007- IT Deliverability Plan, Figure 1, page 4

[260] United Energy, Regulatory Proposal 2021-2026, page 122

[261] United Energy presentation to AER/EMCa May 2020_final, slide 28

[262] United Energy, ATT007 - IT Deliverability Plan, page 11

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 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: United Energy response to IR020

7.3.2 Assessment of United Energy's ICT forecasting methodology

796. We consider that United Energy's ICT forecasting methodology is appropriate. However, we have some concerns with the application of the methodology in individual projects, particularly the assumptions underpinning:

- claimed benefits; and
- its risk analyses.

797. 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.

798. We discuss each of these concerns below and in our observations regarding the proposed expenditure for individual projects, which commences with the Digital Network project in section 7.4.2.

Benefits-modelling can be biased towards over-estimation of benefit streams

799. United Energy has obviously devoted considerable effort to modelling the costs and benefits associated with its benefits-driven ICT projects, such as Digital Networks, Customer Enablement and Intelligent Engineering.

800. However, in our view, United Energy's modelling assumptions are sometimes biased towards the over-estimation of benefits. For example:

- Several critical input assumptions are hard-coded into the model 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 customer time spent accessing the portal is very sensitive to these assumptions;
- In one case, we consider the benefits estimation approach to be 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 United Energy allows.

801. Consequently, when we test the sensitivity of the results and recommendations to variances in key parameters with what we consider to be more reasonable assumptions, we conclude that the extent of the proposed capex is not sufficiently justified.

Risk monetisation methodology considers appropriate risks, but is of limited value in comparative analysis

802. United Energy applies its IT risk monetisation approach to quantify risk across 10 risk categories, shown in the figure below:

Figure 7.3: IT risk categories modelled in United Energy's IT risk monetisation models

IT Risk + **Business Risk**

There are 4 IT Risks:
1. Outages
2. Suitability
3. System sustainability
4. Cyber security breach

There are 6 Business Risks:
1. Reliability impact
2. Compliance risk
3. Customer experience risk
4. Safety risk
5. Bushfire risk
6. Financial loss

Source: UE EMCa May 2020_final, slide 29

803. United Energy has obviously devoted considerable effort to this modelling. However, whilst we typically see its analysis leading to sharp discrimination between the 'do-nothing' counterfactual and the other options, there are typically only relatively minor differences between the other options in its risk modelling. This renders United Energy's assessment of risk as an unhelpful tool in many business cases.

Our top-down cross-checks of expenditure forecasts reveal an over-estimation bias

804. United Energy's cost estimation methodology relies on a '*bottom-up forecast based on experience of providing projects of similar nature, size, scale and complexity*.[263] United Energy 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- and which 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 our view, in these cases, United Energy 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 projects

7.4.1 Overview of proposed Non-recurrent capex

805. United Energy proposes spending a total of $83.4m over the next RCP on six Non-recurrent ICT capex projects, as shown in the table below.

Table 7.5: United Energy's proposed non-recurrent projects for the next RCP - $m, real 2021

Project	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Digital network	4.1	6.5	5.6	1.3	1.8	19.4
Customer Enablement	8.9	1.1	1.9	0.9		12.7
Intelligent engineering		1.4	3.1	0.8		5.4
SAP S/4HANA		3.5	10.9	8.2		22.6
Cyber security	1.9	1.0	0.7	0.8	1.1	5.6
5 Minute Settlements	14.2	3.0	0.1	0.1	0.2	17.7
Non-recurrent	**29.2**	**16.6**	**22.4**	**12.1**	**3.1**	**83.4**

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

263 United Energy presentation to AER/EMCa 20 May 2020 final, slide 30

806. We provide our assessment of five of the six projects in the following sections. We include our observations on the 5-Minute Settlements expenditure in section 7.6.

7.4.2 Digital Network

Overview of the proposed project

Stated need/project driver

807. United Energy advises that this project is part of its response to changing customer requirements, which require it to develop greater visibility of its low voltage (LV) network, including to facilitate increasing penetration of solar PV and electric vehicles.

808. From the project, United Energy proposes implementing '*more sophisticated, monitoring and management capabilities so that we can run the LV network dynamically.'* [264] 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.'*[265]

Options considered by United Energy

809. United Energy has considered three options:[266]

- 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 – 'Increase the current coverage of network devices in a targeted approach to improve LV visibility in addition to option 1 technological capabilities.'

810. The preferred Option 2 for this project includes forecast capex of $19.4m in the next RCP. United Energy proposes to absorb the operating expenditure '*given the importance of this project*.'[267]

811. The preferred option was selected due to the higher NPV ($125.8m for Option 2 vs $97m for Option 1, excluding operating expenditure) and a strong IRR (25.2% vs $21.7%, excluding operating expenditure) derived from application of its modelling.[268]

Composition of the proposed expenditure

812. There are eleven components to the capex required for the Digital Network project. The forecast amounts to be incurred in the next RCP are shown in the table below. Most of these components will require capex for systems refresh in subsequent regulatory control periods and significant operating expenditure.

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264 United Energy BUS 7.08 - Digital network, page 4

265 United Energy BUS 7.08 - Digital network, page 18

266 United Energy BUS 7.08 - Digital network, page 19

267 United Energy BUS 7.08 - Digital network, page 7

268 United Energy BUS 7.08 - Digital network, page 7

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	2.0
	IoT platform for Network Sensors	2.5
	IoT platform for customer sensors	1.4
	LV model extension	3.0
Analytics	Real-time grid analytics platform	2.1
	Real-time LV power flow analysis	1.1
Monitoring	Real-time grid monitoring and control	2.0
	LV management capability	1.1
	Dynamic forecasting capability	1.1
	DER – monitoring capability	1.0
Automation	DER automation	1.1
Total		**18.4**[269]

Source: UE BUS 7.08 - Digital Network, Table 4, page16. Excludes real cost escalation

The Digital Network and Solar Enablement projects are complementary

813. The Solar Enablement and Digital Network projects are complementary but address different needs. United Energy's Digital Network program as proposed will:[270]

- Assist with balancing solar PV systems across phases;
- Enable real-time visibility of voltage rises on the 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).*'

814. We have separately considered these aspects of United Energy's proposed Digital Networks project in our assessment of United Energy'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

815. United Energy has identified four sources of quantified benefits:[271]

- Optimising load control of customer appliances – 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;
- Enhance cost reflective pricing - use existing and future AMI interval data to construct more effective time-of-use tariffs and/or demand management; and
- Detecting electricity theft - identify bypass connections and unregistered DER.

269 There is a discrepancy in this table, which is sourced from UE BUS 7.08, and the amount in the Table 7.6 ($19.4) which is sourced from UE MOD 7.01

270 United Energy BUS 6.06 – Solar enablement, page 22

271 United Energy BUS 7.08 – Digital network, page 20

816. The table below summarises United Energy'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: United Energy's estimate of NPVs for benefit streams for Digital Network project - $m, real 2021

Benefit category	Sub-category	NPV Option 1	NPV Option 2
Customer load monitoring and optimisation	MVA incremental reduction	47.4	48.8
	Unconstrained DER exports	19.0	19.0
EV charging optimisation	Reduced augex	27.0	27.0
	Capacity savings for public EV charging infrastructure	0.0	16.2
	Capacity savings for commercial EV sites	0.0	3.6
Cost reflective pricing	Summer Saver program	1.9	5.2
Reduction in non-technical losses	Theft reduction	1.7	3.2
	Value of un-recorded UMS	0.0	2.8
Total		**97.0**	**125.8**

Source: UE MOD 7.13

817. United Energy describes its benefits streams as all being dependent on the availability of a real-time data platform and depending, on the benefit, a real-time grid analytics platform and real-time monitoring and control.[272] Our understanding is that real-time data cannot be achieved from the existing AMI devices without significant additional investment. AMI devices currently provide 'near' real time data. Also, United Energy 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. United Energy's proposed program will not deliver access to real-time data, nor provide 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.

818. Regardless of whether real-time data is available cost-effectively, we consider that United Energy 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** – United Energy 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 United Energy's Digital networks proposal may assist with 'optimising existing hot water load control,' our understanding of United Energy's analysis is that the benefit derives from adding more load control customers. United Energy states that the technical capabilities (and therefore the cost) from all eleven components of its Digital Network initiative denoted in Table 7.6 are required to enable the benefit stream. Whilst we consider that there is 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 United Energy are fully justified; and

[272] United Energy BUS 7.08 – Digital network, Table 6, page 21

- some of the benefits may be able to be achieved through a combination of price signals (e.g., through tariff reform) and 3rd party providers rather than solely through actions by United Energy.

- **EV charging optimisation** - United Energy describes the benefit as being derived from: (i) monitoring EV charging to understand the impact on the distribution network; and from this information; (ii) designing tariffs to encourage charging at non-peak periods; which will (iii) enable deferment of network augmentation. We consider that EV tariff design does not require real-time data. We consider that the benefits can be achieved without the level of expenditure proposed;
- **Cost-reflective pricing** – United Energy describes the benefit as being derived from: (i) extracting more insights about load and customer behaviour and better identifying network constraints; which will in turn (ii) enable it to develop more effective tariffs and voluntary demand management programs (and extend their coverage); which will in turn (iii) enable deferment of network augmentation. We do not consider that tariff design requires real-time data; and
- **Reduction in non-technical losses** – the benefits of Option 1 are proposed to be achieved by utilising Digital Network technology with its AMI data to allow United Energy to monitor network usage more precisely 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. United Energy 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,[273] or the extra monitoring devices.

Our sensitivity analysis suggests net benefits are marginal

819. The table below shows the capital and operating costs over the 20-year study period in the United Energy cost-benefit model.

Table 7.8: United Energy cost and benefit estimates for Digital Network project - $m, real 2021

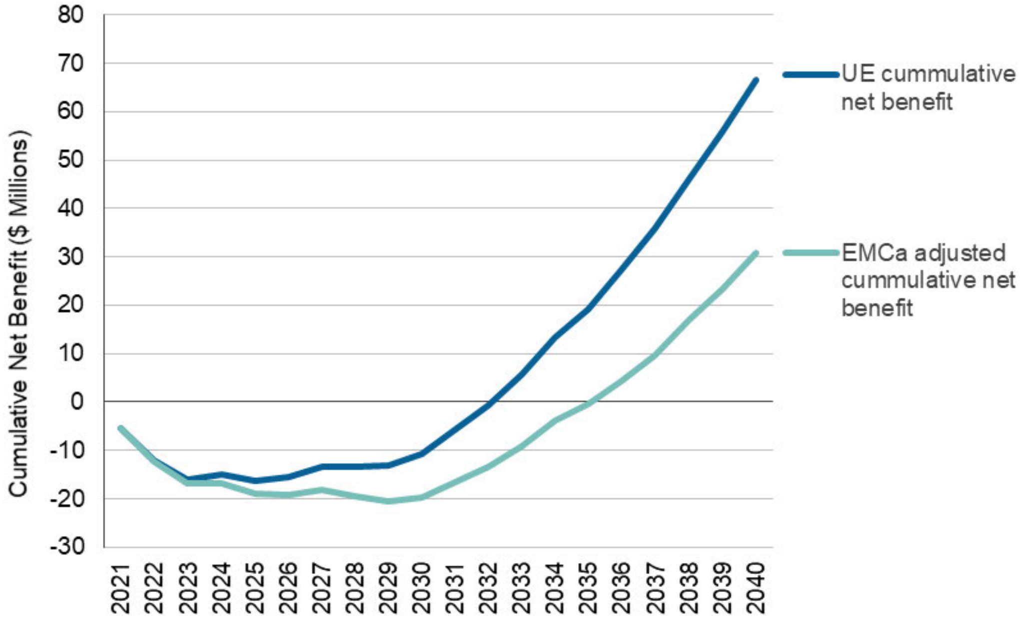
Option	PV Capex	PV Opex	PV Totex	PV Benefit	NPV
1	-30.7	-38.2	-68.9	138.9	70.0
2	-36.5	-24.7	-61.1	125.8	64.7

Source: UE MOD 7.13; NPV includes opex

820. United Energy'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 the costs. As seen from the table above, opex is a significant component of the total estimated cost. As shown in the figure below, when United Energy'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. The figure below shows the result of reducing assumed benefits by 20%, which leads to cumulative net benefits exceeding costs in 2035. In our view, there is significant uncertainty in the benefits streams continuing as forecast beyond 5-10 years and the reduction in United Energy's assumed benefits stream could be much higher than we have assumed in our sensitivity analysis.

273 Real-time data platform, IoT platform for network sensors, IoT platform extension for customer sensors per Table 6 in United Energy BUS 7.08 Digital network

Figure 7.4: United Energy Option 2: Cumulative net benefit - $millions



Source: EMCa analysis of UE MOD 7.13

Progressively extending visibility of the LV network may be prudent in the future

821. There is sufficient evidence that the future use of the LV electricity network is changing and it is increasingly likely that consumers will '*buy, trade, sell, and store electricity and participate in new service markets*.'[274] United Energy 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.'*[275]

822. Whilst extending the visibility of the LV network may be warranted in the future, United Energy has not provided compelling evidence that such visibility is required in the next RCP.

There may be a case for building the foundations of DERMS

823. United Energy reports receiving strong support for developing the foundations to dynamically control inverters from customers and other stakeholders, which in turn requires developing a Distributed Energy Resources Management System (DERMS).[276] According to its roadmap, United Energy proposes to develop DERMS in 2027/28-2028/29.[277] United Energy's business case identifies two Digital Network capabilities which are required to enable DERMS.[278]

824. Whilst we consider there may be some future merit in developing a DERMS, insufficient justification for developing the foundational initiatives was provided in the business case information presented.

Summary of our assessment

825. Our analysis suggests that the Digital Network project, as presented, does not represent a prudent investment for United Energy. United Energy has identified prospective benefits

[274] United Energy BUS 7.08 – Digital network, page 14

[275] United Energy BUS 7.08 – Digital network, page 14

[276] United Energy BUS 6.06 – Solar enablement, page 18

[277] United Energy BUS 7.08 – Digital network, page 34

[278] Dynamic forecasting capability, DER automation per United Energy BUS 7.08 – Digital Network, page 33

from its proposed project, but it has not justified the capex and opex as being required to achieve the majority of the identified benefits.

826. 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 that is required 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 United Energy, at least in the next RCP, can be derived without real time data.

827. Furthermore, the project NPV as claimed by United Energy 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 arrays are already internet connected, providing the opportunity for third parties to provide energy management services.

828. Our position is not altered by United Energy's commitment to absorb the operating expenditure. Based on our assessment, we consider that the absorption of opex by United Energy is not an efficient long-term outcome for customers.

7.4.3 Customer enablement

829. United Energy has apportioned \$12.7m to Non-recurrent expenditure and \$0.6m to Recurrent expenditure in its business case. We refer to the total amount in our assessment.

Overview of United Energy's proposed project

Stated need/ project driver

830. United Energy provides the Energy Easy portal for customers to monitor energy usage. However, 'all customer requests for connections, inspection reports, permit to work forms, and similar, are processed manually. The customer must download the forms and submit them via fax, email or physically via mail. This creates delays in completion of works, customer frustration and dissatisfaction.[279] United Energy'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.'[280]

Options considered by United Energy

831. United Energy considered three options:[281]

- Option 0 – Do nothing (\$0.0m);
- Option 1 - Automated processes, a one-stop-shop portal and enhanced customer experience - automate customer connections and requests, unify the interface with existing online portals and enhance customer experience through improved online capabilities, more effective outage SMS notifications and notifications on the efficiency of customers' rooftop solar output and exports (\$12.3m); and
- Option 2 - Automated processes, one-stop-shop, 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* (\$13.3m).

832. United Energy recommends Option 2 to achieve the following:[282]

- introduce the same eConnect tool as used by CitiPower and Powercor to automate connections and supply requests for all customers (including embedded generators);
- provide more effective SMS notifications during outages;

[279] United Energy BUS 7.02 – Customer enablement, page 5

[280] United Energy BUS 7.02 – Customer enablement, page 5

[281] United Energy BUS 7.02 – Customer enablement, Table 1, page 5

[282] United Energy BUS 7.02 – Customer enablement, page 4

- 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.

833. Although Option 2 is the highest-cost option, United Energy has selected it because it claims that '*it offers customer benefits that outweigh the efficient cost of delivering them*.'[283]

Claimed tangible benefits

834. The table below shows the sources and quantum of benefits claimed by United Energy for Option 2 from improving customer information and access to the information. The primary difference between Options 1 and 2 is that, in the latter, 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.*'[284]

835. In the table below, 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.

Table 7.9: United Energy's estimate of customer and operational benefits for Customer Enablement project – Option 2 - $m, real 2021

Source	Description of benefit	Saving p.a.	Option 2 Benefit ($m p.a.)
Customer time saved	Reduced time spent on calls to enquiries line	47,804 min	0.01
	Reduced time spent on accessing data	4,412,808 min	1.04
	Reduced time spent on website and accessing various portals	2,889,634 min	0.68
	Embedded generators' reduced time on application forms	44,280 min	0.03
	Reduced time on investigating incorrect SMS notifications	290,000 min	0.13
	Time saved from preventing fault calls	73,650 min	0.03
	eConnect customer benefits – time saved from automated application	458,910 min	0.11
	eConnect customer benefit – vale to residential customers from shorter connection times	1 day per application	8.13
Operational benefits	Reduced calls to contact centre staff	4 FTE	0.44
	Reduced staff required to process manual generator requests	0 FTE	0.00
	Estimated total average annual savings[285]	**Option 1** **Option 2**	**4.01** **4.40**

Source: EMCa analysis of UE MOD 7.21

** 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*

283 United Energy BUS 7.02, page 19

284 United Energy BUS 7.02, page 18

285 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

Claimed NPV of costs and benefits for 2021-2031 period

836. The table below summarises United Energy's cost-benefit analysis.

Table 7.10: Summary of United Energy's cost-benefit analysis for Customer Enablement project - $m, real 2021

Option	PV capex	PV Benefit	NPV
Option 0	0	0	0
Option 1	-17.0	56.6	39.6
Option 2	-18.3	62.7	44.4

Source: UE MOD 7.21

Our assessment

837. Based on its interpretation of customer survey results, United Energy proposes spending $13.3m in Recurrent and Non-recurrent capex in the next RCP and a further $6.6m over the following five years to provide eight customer service enhancements. United Energy estimates that the customer enablement project will reap a net economic benefit of $44.4m over 10 years. However, the claimed benefits are derived primarily from three initiatives:

- earlier connections (via introduction of eConnect);
- reduced time spent on accessing data (via introduction of mobile phone app); and
- time saved on the website and accessing various portals (via AI and single login ID).

838. For all three initiatives, we have fundamental concerns about the claimed benefits as discussed below.

eConnect benefit calculation is overstated

839. United Energy assumes that the eConnect service will speed up the connection process for customers by one day and that customers value this improvement at an amount equivalent to the Victorian average value of customer reliability (VCR). This equates to a benefit of $8.5m per year.

840. In our view, applying the VCR is inappropriate. Providing a connection with power is not equivalent to interrupting an existing customer's power supply. United Energy itself ascribes a value of $80 to connecting a customer one day early, which is 'UE's ancillary network charge for 'express move in' during business hours.' We consider this to be a more reasonable value.

841. Valuing the faster connection process at $80 per day for the assumed 15,297 connection applications per year reduces the annual benefit stream to $1.2m.

Benefits in the two other largest sources are biased by unreasonable assumptions

842. United Energy'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 United Energy customers – using $0.236 as the value of a saved customer minute; and
- operational benefits to United Energy from reduced call centre activity as a result of reduced customer calls.

843. United Energy 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.

844. Of greater concern is United Energy's assumption regarding the number of customers that will register to use its website and portals. Two of its largest benefit streams are derived from reduced customer time to access its portals. United Energy forecasts that it will have

an average of 735,468 customers over the next RCP and assumes that an average of 50% of these customers (367,734) will be portal users during the whole of the next RCP:

- to calculate the benefit of 'Reduced time spent on accessing data', United Energy assumes all 367,734 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', United Energy assumes that 100% of the assumed registered users (i.e., 367,734) will avoid 4 minutes of wasted time per year; and
- it assumes that there is no overlap in these two benefit streams.

845. We consider that these assumptions are unreasonable for the following reasons:

- United Energy has not provided any justification for the assumption that: (i) there will be 367,734 (50%) portal users; (ii) each of these customers will access the web site on average 4 times per year, and (iii) each customer will save 3 minutes per portal access. We note that approximately 15% of VPN's customers are registered to use its equivalent portal. If this ratio were applicable to United Energy, it would have approximately 110,000 registered users of its portal. In this context we consider it to be unlikely that 367,734 of United Energy's customers will use the portal on average four times a year over the next RCP; 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 (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.

Alternatives to United Energy's proposed mobile app may erode assumed benefits

846. United Energy proposes $1.0m incremental capex in the next RCP for providing near real-time data[286] on a mobile phone app on the assumption that:[287]

- 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 electricity usage data into their existing applications and products, thus reducing United Energy's costs to develop a stand-alone application .

847. It is not clear to us why United Energy 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, but alternatively they may choose to contract with their retailer or a third party for that information or for those parties to optimise their energy production and use for maximum customer benefit.

848. Consequently, in our view, the benefits claimed by United Energy in its business case may already be captured by 'competitors' and/or may be eroded quite quickly by competitors who have more to gain in offering customers this type of service.

849. It is our view that speculative investments by United Energy 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.

Using more reasonable user registration numbers renders the project uneconomic

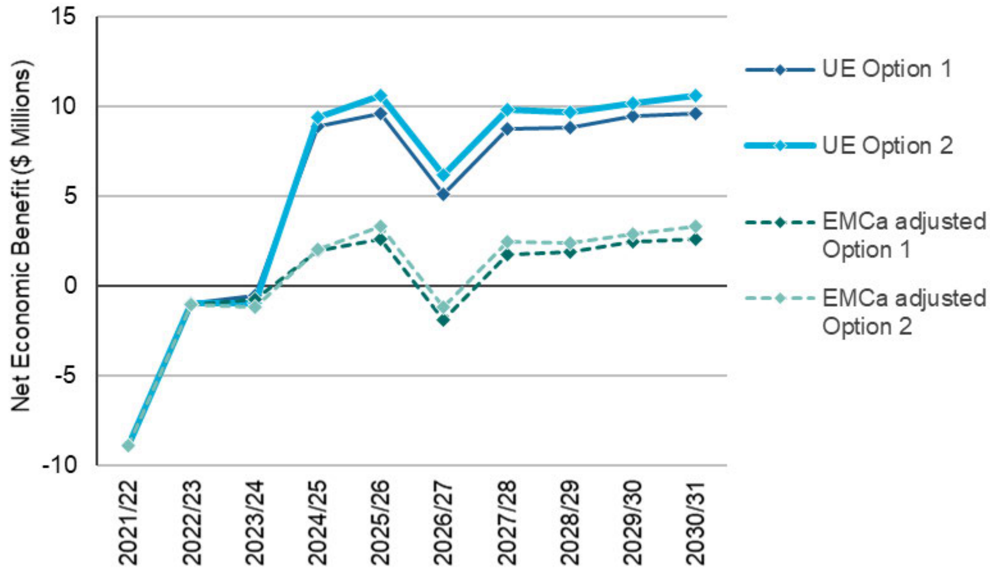
850. The figure below shows that the project NPV is sensitive to the assumed number of users and the benefit ascribed to improving the timing of connections by one day. Even without accounting for our concerns about other factors that may impact the claimed net economic

[286] United Energy proposes that myEnergy data will be refreshed every 4 hours, United Energy BUS 7.02, page 18

[287] United Energy BUS 7.02, page 18

benefit, by reducing the assumed registered users by 30% and the benefit from eConnect connections to $80/day saved, the project does not achieve breakeven until the next RCP. The NPV of Option 1 with these assumptions is -$1.0m, but Option 2 has a positive NPV of $1.8m, due largely to the benefit stream from the eConnect portal. Without the eConnect portal, the NPV of Option 1 is -$8.1m and the NPV of Option 2 is -$5.3m.

Figure 7.5: Cumulative net benefit for Customer Enablement project - $m, real 2021[288]



Source: EMCa analysis using PAL MOD 7.21 Note: NPV are totals for United Energy and Powercor

Summary of our assessment

851. We have considered United Energy's cost benefit analysis and consider that neither options 1 or 2 as presented are likely to be NPV positive without the assumed eConnect benefit. This indicates that the capital required to provide the eConnect functionality is important, but that incurring expenditure for some other features may not be prudent.

852. 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 (that might include contact centre AI), improving the effectiveness of SMS notifications, and the eConnect portal. We consider that these features are likely to address the core complaints from customers (as reported in United Energy's business case) at a reduced cost.

853. United Energy 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.

7.4.4 Intelligent engineering

Overview of the proposed project

854. United Energy proposes to spend an estimated $5.4m 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'*.[289] This is referred to as Option 2 by United Energy.

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288 EMCa modified inputs applied: number of users of portals reduced by 30% and daily benefit of 1 day faster connections through eConnect reduced to $80/day/connection

289 United Energy BUS 7.07 Intelligent Engineering, page 5

Options considered by United Energy

855. United Energy has identified three options, as shown in the table below.

Table 7.11: United Energy options summary for Intelligent Engineering project - $m, real 2021

Option	Capex Next RCP	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	4.7	-6.3	6.6	0.3
2 - Base intelligent engineering capability plus DBYD mobile application	5.4	-7.2	14.5	7.3

Source: EMCa analysis of United Energy BUS 7.07

Our Assessment

The project drivers present a reasonable case for action

856. Firstly, United Energy advises 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:[290]

- '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.'

857. United Energy further advises that:[291]

- as the Victorian Government aligns its assets to GDA2020[292] and improves its cadastre, the growing disparity between its asset data (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.

858. United Energy also advised that the limitations of the Victorian cadastre and United Energy's GIS described above means it cannot provide accurate location information of underground assets. United Energy therefore does not allow digging within 30 meters of the indicated location of its assets in its GIS (using the DBYD service) which can result in delays. Furthermore, United Energy claim 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.[293]

859. United Energy identified issues with its Map Insights platform[294] which relies on United Energy's GIS data with overlays from the Victorian government cadastre and other external sources. United Energy advised that '*due to lack of accuracy between our GIS and other*

290 United Energy BUS 7.07 Intelligent Engineering, page 5

291 United Energy BUS 7.07 Intelligent Engineering, page 5

292 Australia's Geospatial Reference System

293 United Energy BUS 7.07 Intelligent Engineering, page 7

294 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 (United Energy BUS 7.07, page 7)

external mapping sources, we are unable to extend our platform to a wider range of stakeholders at present.'[295]

860. On the basis of widening data discrepancies between United Energy's GIS 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 RCP rather than waiting until the next RCP.

Our sensitivity analysis suggests the net benefits are likely to be achievable

861. United Energy has proposed four initiatives to: (i) reduce safety risk and the costs of asset damage; (ii) improve operational efficiency for United Energy and third parties; and (iii) improve asset information exchange with stakeholders.[296] The initiatives comprise:

1. introducing a master data management system;
2. conflating its GIS records to the physical earth;
3. enhancing Map Insights platform; and
4. improving DBYD accuracy and access to information.

862. The benefits are inter-related, with United Energy identifying lower customer costs ($2.0m pa) from: [297]

- the time saved from fewer delayed projects ($130k); and
- the time saved from having a mobile DBYD app ($1.8m).

863. Operational benefits commence in 2023/24 with a maximum annual benefit of $1.1m realised following completion of the project in 2025/26 (the 10 year average is $0.9m).[298] In our opinion, the benefit quantification approach is reasonable, although the assumptions underpinning the savings are not substantiated.

864. Given the somewhat speculative nature of the benefit assumptions underpinning United Energy's NPV results, we considered that it was prudent to undertake a sensitivity analysis. United Energy did not provide sensitivity analysis results, nor the facility to do so directly in its model.

865. Nonetheless, we have used United Energy'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.

866. 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.

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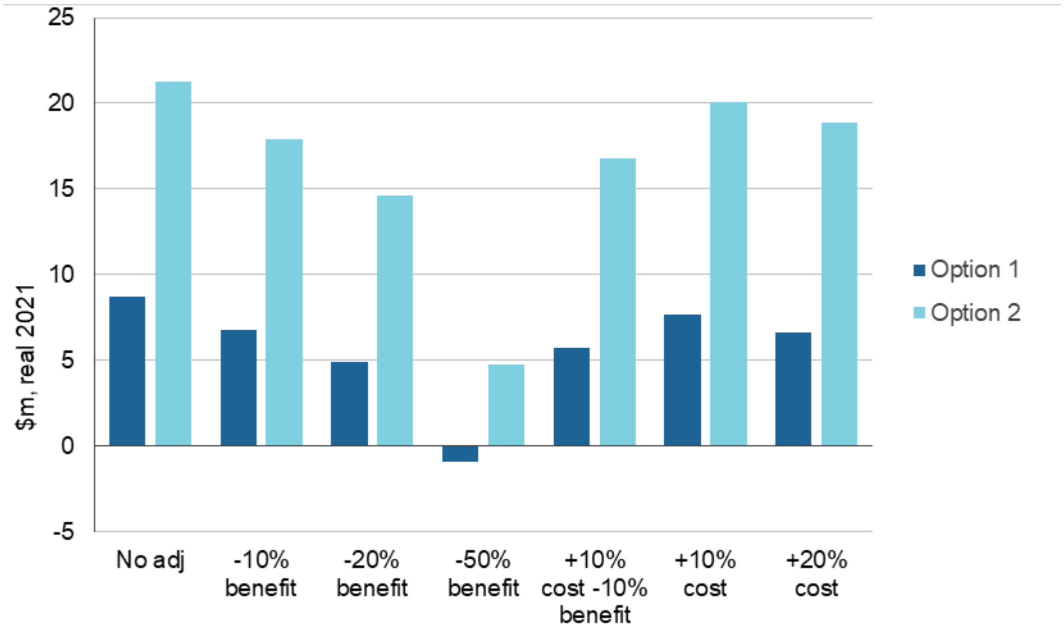
295 United Energy BUS 7.07 Intelligent Engineering, page 7

296 United Energy BUS 7.07 Intelligent Engineering, page 5

297 United Energy MOD 7.11, Benefits worksheet

298 United Energy MOD 7.11, Benefits worksheet

Figure 7.6: Sensitivity analysis of United Energy project benefits for Intelligent Engineering project - $m, real 2021



Source: EMCa analysis of Powercor MOD 7.11 which also applies to United Energy

United Energy's proposed Option 2 is likely to maximise net benefits

867. As a further check on the prudency of Option 2, we considered whether there was merit in United Energy proceeding with only the highest value aspects of its project, namely the DBYD mobile app and fewer on-site inspections.

868. 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.

Summary of our assessment

869. Whilst we have concerns that the benefits claimed by United Energy 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 proposed initiatives have merit as a bundled program of work.

870. Our analysis suggests that the project capex for United Energy's Option 2 of $5.4m is likely to be prudent and reflective of an efficient level.

7.4.5 SAP Upgrade

871. The SAP upgrade project is common to United Energy, Powercor and CitiPower. Capital costs are allocated 25% to Powercor, 25% to CitiPower, and 50% to United Energy. The project includes both Recurrent and Non-recurrent expenditure. Unless otherwise stated, our assessment is of the total costs and benefits attributable to VPN/UE (i.e., United Energy plus Powercor plus CitiPower).

Overview of the proposed project

872. SAP Enterprise Resource Planning (ERP) software is used to run VPN's and United Energy's payroll, HR, finance, 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.

873. 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

874. VPN/UE have identified five options for providing a '*stable, compliant and fit-for-purpose*'[299] ERP, as shown in the table below.

Table 7.12: VPN/UE's options summary for SAP Upgrade project - $m, real 2021[300]

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

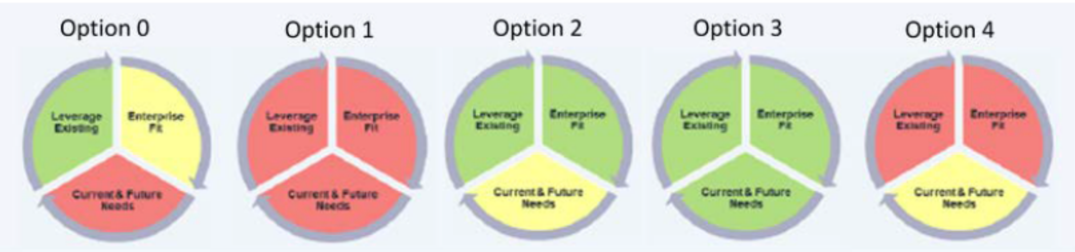
Summary of VPN/UE's options analysis

875. The figure below presents a summary of VPN/UE's options analysis. The three dimensions that it considered are:[301]

- 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
- Current and future needs – 'Solutions must be sustainable, scalable, and secure.'

876. 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 7.7: Summary of VPN/UE's initial SAP options analysis



Source: EMCa modification to PAL BUS 7.01, Table 5

VPN/UE's preferred option

877. VPN/UE has chosen Option 3 because:[302]

299 Powercor BUS 7.01 SAP S4HANA, page 4

300 Options 1-4 include costs for maintaining currency of SAP ECC6 in addition to the SAP S/4HANA upgrade. Costs are total costs for United Energy, Powercor and CitiPower

301 Powercor BUS 7.01 SAP S4HANA, page 18

302 Powercor BUS 7.01 SAP S4HANA, page 28

- It avoids the significant risks and operational expenditure of options 0 and 4;
- Continues with direct SAP vendor support without disruption;
- It is the most affordable way to achieve and maintain a stable, compliant, and fit-for-purpose ERP;
- It supports integration of the three businesses, allows new capabilities to be built, and simplifies future ERP maintenance and support needs; and
- It 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

878. VPN/UE has used a combination of quantitative and qualitative analysis to select the preferred option. The qualitative assessment summarised is supported by information in the business case and the dimensions considered provide a reasonable perspective on organisational fit.

879. 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[303] and Business impacts.[304] Whilst we do 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

880. Option 0, do nothing, will not incur zero costs, as United Energy'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 cost benefit analysis, United Energy should not define the costs of options 1 to 3 relative to a zero-base counterfactual.

881. 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 of reducing opex, deferring upgrade costs and reducing dependency on the OEM vendor. United Energy has provided a comparison of the different reliability/stability performance between Powercor/CitiPower and United Energy over the period 2017-2020. During this time, United Energy had over 15 times the volume of incidents.[305]

882. 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.'*[306] 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.

883. We are also satisfied that deferring replacement of SAP ECCC6 beyond 2025 is unlikely to be prudent as:[307]

- There will be a decrease in the provision of system fixes and support packs through to 2025 from SAP;
- United Energy/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;

303 Outage, suitability, and system sustainability – as descr bed in Table 15, p31, PAL BUS 7.01

304 Reliability, compliance risk, customer experience risk, safety risk, bushfire risk, and financial risk – as described in Table 15, pp 32-33, PAL BUS 7.01

305 United Energy BUS 7.01 SAP S4HANA, Table 8, page 22

306 United Energy BUS 7.01 SAP S4HANA, page 22

307 United Energy BUS 7.01 SAP S4HANA, pages11-13

- 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).

884. 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…'*[308] 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

885. 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.

886. 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*.'[309] 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'*[310] and where 'this option' is the single instance proposed in Option 3.

887. 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.

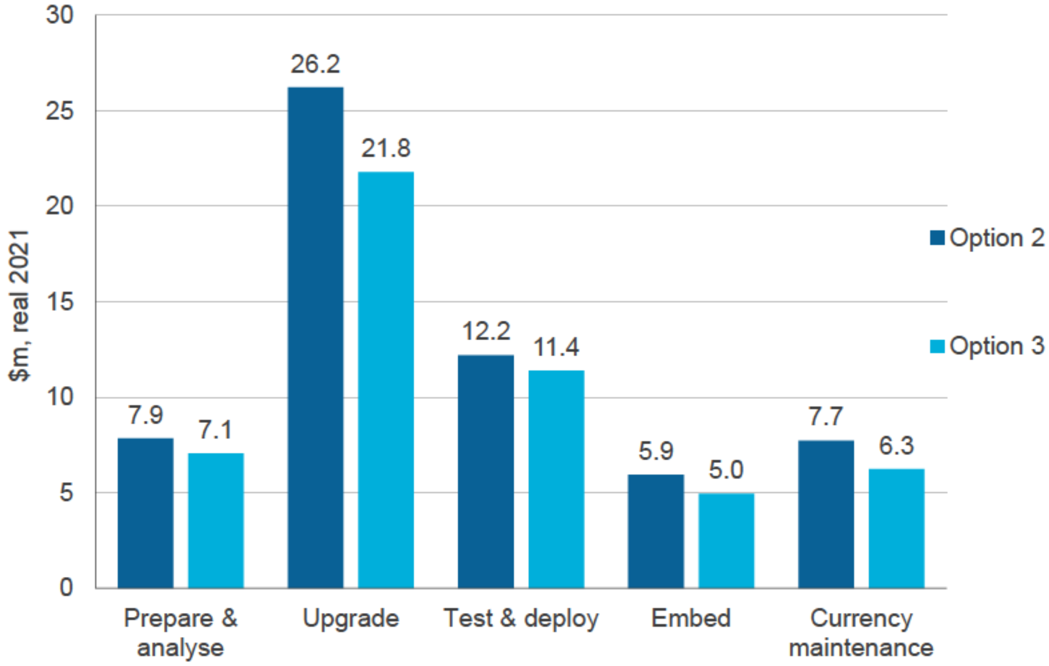
888. With this in mind, we looked closely at the costs allowed for Options 2 and 3 for preparation versus the costs involved for establishing and maintaining two instances of SAP (Option 2) and one instance (Option 3). The figure below shows the comparative cost estimates for various aspects of the work.

308 Powercor BUS 7.01 SAP S4HANA, pages 25

309 Powercor BUS 7.01 SAP S4HANA, Table 11, page 24

310 Powercor MOD 7.03 SAP risk

Figure 7.8: Comparison of VPN Option 2 and Option 3 cost assumptions for SAP Upgrade project - $m, real 2021



Source: EMCa analysis of PAL MOD 7.02, also applies to CitiPower and United Energy

889. It is possible that VPN/UE has allowed for extra time and resources in its ‘Prepare & analyse’ cost estimate, given that the ‘Prepare & analyse’ cost for Option 3 is, at $7.1m, significant and comprises 35,000 hours of labour and $5.7m of materials and contracts.[311]

890. 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.

891. Based on the number of SAP modules and the organisational business process complexity for 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. We note that, while more complex, the Option 2 cost of $60m is also reasonable.

Maintaining the currency of the two SAP instances during the transition period is prudent, but the cost seems unreasonably high

892. 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% (total of $2.4m) by refreshing the SAP ECC6 versions in either 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

893. VPN and United Energy have selected a reasonable range of options for dealing with the 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 experience, to conclude that upgrading to SAP S/4HANA within the next RCP (Option 3) is likely to be the prudent approach.

894. Our analysis suggests that refreshing the existing ERP in 2021/22 and 2022/23 is unlikely to be prudent – we consider that only one refresh (e.g., in 2022/23) prior to the 2024/25 go-live

[311] Powercor MOD 7.02 SAP cost

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

Overview of the proposed project

895. United Energy proposes $13.1m Recurrent capex to maintain current levels of cybersecurity capabilities and Non-recurrent capex of $5.6m to enhance its cyber security posture, for total forecast capex in the next RCP of $18.7m. Its justification for the 'enhancement' capex is based on the consequences of a cyber security breach, which are potentially significant, and:[312]

- 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 (Cth) was developed in recognition of the evolving national security risks to infrastructure including electricity assets;
- Its self-assessment against the Australian Electricity Sector Cyber Security Framework (AESCSF) developed by industry and AEMO;
- Its regulatory obligations under the Australian Privacy Act 1988 which, among other things, requires United Energy to take reasonable steps to protect personal information it holds; and
- It is ranked as one of United Energy's top 10 risks on its risk register.

896. United Energy considered four options in its cyber security business case, as summarised in the table below. United Energy has selected Option 2 for a proposed cost of $18.7m, comprising $13.1m in Recurrent and $5.6m in Non-recurrent expenditure.[313]

Table 7.13: United Energy's options summary for Cybersecurity project - $m, real 2021

Option	Cost	Risk
0 Do Nothing - do not invest in maintaining cyber security capabilities	0.0	150.2
1 Maintain Currency – maintain existing cyber security capabilities as is	13.1	44.8
2 Optimise Effectiveness – build on Option 1 by optimising the effectiveness of existing cyber security capabilities by increasing coverage	18.7	22.4
3 Expand Analytics Capability – build on Option 2 by expanding cyber security monitoring and behavioural analytics capabilities	27.2	11.8

Source: United Energy BUS 7.04, Table 1, page 6

Our assessment

Cybersecurity obligations do not yet apply to DNSPs

897. The AESCSF provides a consistent means for businesses to assess and improve cyber security maturity, but its use is currently voluntary. Whilst we understand that the intention is for mandatory maturity levels to be introduced into regulations in time, this has not yet been done.

312 United Energy BUS 7.04 Cyber security, pages 6-9

313 We note that the expenditure provided in BUS 7.04 Cyber security, Table 7 is reversed between recurrent and non-recurrent expenditure

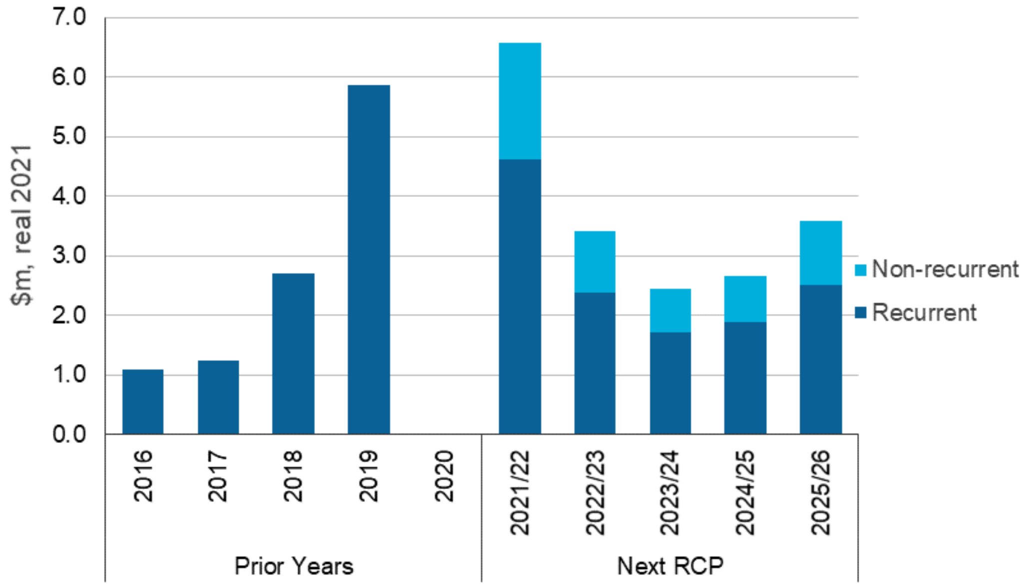
898. Nonetheless, given the escalating risk of cyber threats, which is evident from recent cyber-attacks in Australia,[314] a prudent distribution network operator should align its cyber security posture to align with the recommended MIL2/SP-2 level.[315]

United Energy proposes a 60% reduction in Recurrent cybersecurity capex

899. The figure below compares the available 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.

900. Compared to the four available years of historical capex, United Energy proposes almost the same average annual Recurrent capex in the next RCP. Based on the level of detail provided in United Energy's cost model, we consider the Recurrent capex estimate to be reasonable.

Figure 7.9: United Energy's historical and forecast cybersecurity capex - $m, real 2021[316]



Source: EMCa analysis of United Energy's response to IR020 (Table 3) and UE MOD 7.05

Options 0, 1, and 3 are not prudent approaches

901. 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), or United Energy's cyber security risk exposure. In our view, a prudent operator would not pursue these options.

902. Option 3 provides enhanced 'security monitoring and behavioural analytics' in addition to the full scope of Option 2 (as discussed below) to *'uplift our 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.'*[317] United Energy concludes that Option 3 does not provide sufficient additional security benefits given the additional investment of $8.5m over 5 years.

[314] E.g. refer to https://www.theguardian.com/australia-news/2020/jun/19/

[315] Recent updates to the AESCSF framework (version 2019-8) incorporated Security Profiles (SP) in which distr bution 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

[316] VPN provided actual for 2016 – 2019 based on calendar year (Powercor/United Energy response to IR020) while 2021/22 – 2025/26 are based on financial year. We converted 2016 – 2019 into real $2021

[317] United Energy BUS 7.04 Cyber security, page 19

903. In our view of the Options considered by United Energy, we agree that Option 2 is preferable to Options 0, 1 and 3.

United Energy's outcome measured against the AESCSF maturity levels is reasonable

904. United Energy's business case is silent on what Maturity Indicator Level (MIL) it expects to achieve from the proposed Option 2 investment. We therefore asked United Energy to explain:

- What the proposed capex achieves in terms of the MIL and in terms of the 23 NIST[318] categories that underpin the five NIST functions per the AESCSF; and
- Where the proposed work program positions United Energy against the MIL/SPs following completion of the proposed capex program.

905. In summary, United Energy's response is that it: (i) sought to ensure that it has 'balanced coverage' defined by the NIST functions and AESCSF domains; and (ii) did not use the MIL/SP target as its primary driver, and that it forecasts *a 'a MIL between 2-2.3 at the end of the RCP.'* [319]

906. Based on the information provided and from our experience,[320] we consider that United Energy'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

907. It was not clear to us from its business case how United Energy accounts 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, United Energy advises that: [321]

> *'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.'.*

908. United Energy also states that its cybersecurity proposal assumes that it will ensure the portfolio of IT assets remain in-support throughout the next RCP. We are satisfied with this explanation and consider that the incremental expenditure proposed is unlikely to double count costs.

United Energy's cost estimate is reasonable

909. Based on our assessment of United Energy's cost estimation methodology, we are satisfied that the cost estimate for Recurrent and Non-recurrent expenditure is likely to be representative of an efficient level.

Summary of our assessment

910. United Energy proposes $13.1m in Recurrent capex and $5.6m in Non-recurrent opex. Our assessment suggests that United Energy's forecast cyber security capex for the next RCP is commensurate 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;

[318] National Institute of Standards and Technology

[319] United Energy's response to IR020, question 10

[320] Including from providing advice to Australian businesses in Australia and overseas, and from reviewing utilities' cyber security expenditure and expenditure forecasts

[321] United Energy's response to IR020, question 12

- 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 the AEMO.

911. However, as far as we are aware, there is currently no regulatory obligation to achieve MIL 2 (or higher).

7.5 Assessment of selected Recurrent ICT capex

7.5.1 Overview of proposed Recurrent ICT capex

912. United Energy proposes spending a total of $103.2m over the next RCP on Recurrent ICT capex, as shown in the table below.

Table 7.14: United Energy's proposed recurrent ICT projects - $m, real 2021

Project	2021/22	2022/23	2023/24	2024/25	2025/26	Total
BI/BW	0.5	1.1	0.5	0.1	0.1	2.3
Customer Enablement		0.6				0.6
Cyber security	4.6	2.4	1.7	1.9	2.5	13.1
Device replacement	0.8	0.5	0.5	0.6	0.7	3.1
Enterprise Management Systems - Non-SAP	3.0	1.7	2.1	1.2	0.8	8.7
Facilities' security	0.1	0.6	0.7	3.2	0.1	4.7
General compliance	1.6	1.6	1.6	1.6	1.6	8.2
ICT Infrastructure Refresh and Cloud migration	3.9	4.4	2.9	8.4	3.2	22.8
Market Systems	2.8	0.4	1.0	0.3	2.8	7.4
Network Management	5.0	5.2	4.0	4.2	6.4	24.9
SAP S/4HANA	0.9	1.5			0.7	3.1
Telephony	3.0	0.6	0.6		0.2	4.4
Recurrent	**26.3**	**20.6**	**15.6**	**21.4**	**19.3**	**103.2**

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

913. Recurrent capex is incurred in 12 projects, including Facilities Security (which is discussed in section 8). We discuss a further three projects in our assessment of Non-recurrent capex, namely: (1) Customer Enablement; (2) SAP S/4HANA; and (3) Cybersecurity. These projects are discussed in section 7.4.3, section 7.4.5 and section 7.4.6, respectively. 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 refresh and cloud migration

Overview of the proposed project

914. The majority of United Energy'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.

915. For the next RCP, United Energy 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 its on-premise infrastructure to cloud hosting.

916. United Energy recommends Option 2 – balanced (or hybrid) cloud migration at a capital cost of $22.8m and an opex step change of $4.5m, 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 United Energy

917. The table below summarises United Energy's risk-cost assessment of the four options.

Table 7.15: United Energy's summary of options for ICT Infrastructure cloud migration project - $m, real 2021[322]

Option	Description	Capex	Incremental opex	NPV expenditure	Risk
0 - Do nothing	No refresh/growth of existing on-premise infrastructure; no migration to cloud	0.0	0.0	0.0	222.2
1 - On-premise infrastructure refresh	Do not migrate existing on-premise infrastructure to cloud hosting	31.9	0.0	29.2	3.9
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	22.8	4.5	25.0	3.9
3 - Aggressive cloud migration and refresh remaining on-premise infrastructure	Migrate core ICT applications plus 10% of non-core applications pa to cloud hosting; refresh remaining on-premise infrastructure.	22.4	6.4	26.5	3.9

Source: UE BUS 7.10, Table 6

Our assessment

United Energy's selected strategy to move progressively to the cloud is sound

918. Option 0 is not a viable option. It is not based on good industry practices and serves only as a counterfactual for assessment of Options 1-3.

919. Option 1 - on premise infrastructure refresh - is not recommended by United Energy 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.

920. United Energy'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. United Energy identifies the benefits of adopting a hybrid cloud approach as including:[323]

- '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

322 The NPV analysis is undertaken over 5 years

323 United Energy ATT 046 BDO Cloud review, page 17

- Provide greater ability to manage peak demands aligned to business needs.'

921. The identified benefits are consistent with our experience and the trend we observe within the industry. We therefore consider United Energy's strategy of moving progressively to the cloud, as proposed in Options 2 and 3, to be superior to Option 1.

922. United Energy's preferred 'balanced' strategy (Option 2):[324]

- 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.

923. United Energy obtained advice from an expert consultant that Option 2 '…reflected the best value and most achievable option for an alternate IT Hosting strategy during the next regulatory reset period.'[325] 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: [326]

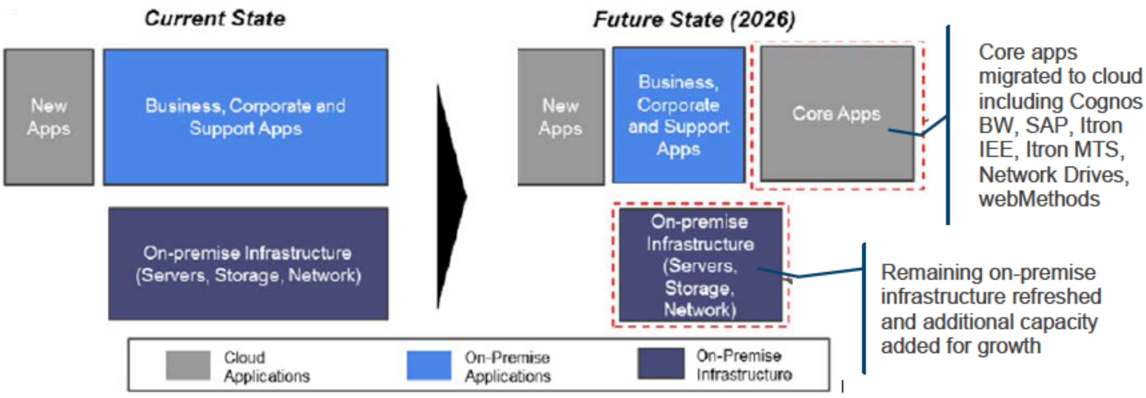
> *'Adopting this scenario carries some additional risk, as it requires CitiPower, Powercor & United Energy to continue developing a high level of internal maturity in cloud adoption and understanding of its application compatibility with cloud based platforms.'*

924. We are not in a position to comment on United Energy's relative maturity regarding cloud adoption. In accepting its consultant's advice in adopting Option 2, we assume that United Energy acknowledges its relative lack of maturity compared with cloud adoption. However, we note that its risk analysis (shown in Table 7.15) does not distinguish between the risk cost of Options 2 and Options 3.

925. 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.

926. The figure below illustrates the current and future states of the planned cloud migration and refresh of remaining on-premise infrastructure following implementation of United Energy's preferred option.

Figure 7.10: Current and Future state following implementation of United Energy's preferred option 2



Source: EMCa modified version of United Energy's Figure 3, page 18, UE BUS 7.10 Cloud infrastructure

927. As shown in the diagram above, United Energy 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.

324 United Energy ATT 046 BDO Cloud review, page 5

325 United Energy ATT 046 BDO Cloud review, page 29

326 United Energy ATT 046 BDO Cloud review, page 21

We had similar concerns with respect to the BI/BW[327] business case costs. Based on a response from VPN[328] (noting that the business case structure and IT integration strategies for VPN and United Energy are the same), the demarcation of proposed capex and opex across the three business cases is follows:

- The Cloud infrastructure business case (UE BUS 7.10):
  - 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 (UE 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 (UE 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.

928. 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, we note that if the Cloud project slipped even slightly VPN/UE will not have the data ready for commencement of the SAP/HANA project.

The proposed Option 1 capex for refreshing and growing the on-premise infrastructure is not adequately justified

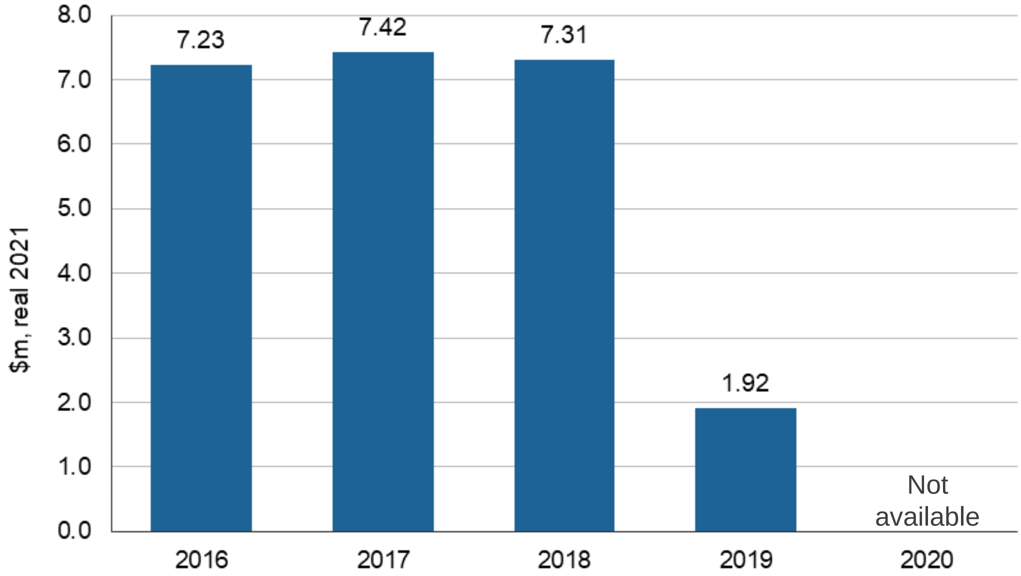
929. We requested the historical recurrent IT infrastructure capex from United Energy as a means of testing the reasonableness of the $9.1m reduction in on-premise capex for Option 2 compared to Option 1 (on-premise infrastructure refresh).

930. The figure below shows the historical data provided. The annual average capex is $6.0m. The reason for the lower 2019 capex is not explicitly explained and the 2020 figure was not provided.

[327] Business Intelligence/Business Warehouse

[328] VPN response to IR048

Figure 7.11: Historical ICT and forecast infrastructure capex - $m, real 2021



Source: EMCa analysis of United Energy response to IR020 Table 3 and UE BUS 7.10, Table 12

931. United Energy's forecast of a 14% increase in data storage requirements over the next RCP is cited as a reason for higher ICT capex for on-premise infrastructure refresh costs.[329] We consider that increasing storage requirements are likely over the next RCP for the reasons stated by United Energy. However, in our experience, on-premise infrastructure costs have been falling significantly, particularly the per unit cost of storage, which is likely to explain why infrastructure costs from 2016 to 2018 have been flat rather than increasing with growth in customer numbers and in volumes of business-related and asset-related data. We consider that, for Option 1, falling costs of storage are likely to offset the 14% increased storage requirements over the duration of the next RCP.

932. United Energy's average annual capex for the next RCP is $4.6m. This is less than the 2016-2018 annual average historical capex, but more than the four-year average of $6.0m. We note that United Energy advises that it has based its forecast ICT costs on vendor quotes where available, but the basis for the costs in this business case is not explicitly stated. Relevant cost information in the cost model is hard-coded without reference to sources.

933. Without knowing the 2020 capex to allow for a better comparison with the historical trend, it is difficult to assess the reasonableness of United Energy's proposed recurrent capex for Option 1. However, the capex estimate does not appear to be excessive.

United Energy's estimate of the cost of the residual on-premise infrastructure included in Option 2 appears to be overstated

934. To determine the reduction in infrastructure costs afforded by shifting some infrastructure to the cloud, United Energy has first identified the assumed proportions of infrastructure material costs that are currently used by each of the core and non-critical applications that United Energy propose transitioning to the cloud. The negative percentages (indicating reductions) are summarised in the table below.

[329] United Energy BUS 7.10 – Cloud infrastructure, pages 12-13

Table 7.16: United Energy's assumed material-related capex reductions from migration to IaaS (next RCP)[330]

Application	Server	Storage	Database (Exadata)	Backup	Network	Database (HANA)	Option 2 materials saving ($m, 2021)
Itron IEE	-1%	0%	-10%	-10%	-1%	0%	-0.8
Itron MTS	-1%	0%	-5%	-5%	-1%	0%	-0.4
SAP ERP	-1%	0%	-10%	-10%	-1%	0%	-0.8
Cognos BW	-2%	0%	-10%	-10%	-1%	-100%	-2.0
SharePoint	-3%	0%	0%	0%	-1%	0%	-0.1
webMethods	-1%	0%	-10%	-10%	-1%	0%	-0.9
Non-critical apps	-5%	0%	-10%	-10%	-1%	0%	0.0
Network drives	-1%	0%	-10%	-10%	-1%	0%	-0.9
Total	**-15%**	**0%**	**-65%**	**-65%**	**-8%**	**-100%**	**-5.9**

Source: UE MOD 7.15 per Option 2

935. The reduction to capex afforded by Option 2 (compared to Option 1) is derived by applying the negative percentages to the materials component of cost, resulting in a reduction of $5.9m and the model assumes a further 20% of this amount will be labour savings and 35% of this amount will be contracts savings, for a total savings of $9.1m.

936. United Energy did not provide compelling justification in its model or in its business case for the assumptions used in Table 7.16. 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, United Energy advised that: [331]

- 'Our estimated capex reduction for migrating these non-core eligible applications are based on the current share of infrastructure for each application'; 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.'

937. We have reviewed the proposed percentages in the table above in light of our experience, the response to the information request, and the information in Table 15 in the business case. We consider United Energy's estimates to be reasonable, with one exception – United Energy has not included any storage capex cost reductions from its proposed cloud migration activity. This omission is not explained explicitly.

Opex step change appears to be reasonable

938. United Energy advises that migrating applications to cloud hosting was based on vendor roadmaps[332] and external consultant advice.[333] 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 United Energy to source vendor estimates as the basis for its forecast. Based on our review of the itemised costs, they appear to be reasonable estimates.

330 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 UE's model. United Energy did not explicitly include storage cost reduction – we have inserted 0%

331 United Energy's response to IR020 question 14

332 United Energy BUS 7.10 Cloud infrastructure, page 13

333 United Energy ATT046 – BDO Report for cloud – Nov2019

The proposed opex reduction in the next RCP to account for fewer on-premise infrastructure is reasonable

939. United Energy estimates the reduction in opex from migration to cloud hosting as 5% of the capex reduction. United Energy did not provide justification for this amount in its business case or model. In response to our request for more information, United Energy advised that '*achieving material operating expenditure savings will only occur in future regulatory periods.'*[334] Based on our experience, we consider that United Energy's estimate for the next RCP is reasonable.

Summary of our assessment

940. Our assessment suggests that:

- United Energy'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.
- United Energy's selected Option 2 'balanced cloud migration' appears to be an appropriate choice and is informed by external advice.
- United Energy's estimates for capex and opex savings and opex increases for its preferred option are based on reasonable methodologies.
- United Energy's proposed capex for refreshing and growing its remaining on-premise infrastructure has not been adequately justified.
- United Energy's opex step change to cover the cloud hosting fees of $4.5m[335] is likely to be reasonable.

7.5.3 Network Management Systems

Project overview

941. United Energy proposes to invest $24.9m 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 our ability to effectively monitor and manage our electricity network.'*[336]

942. United Energy considered the three options shown in the table below and selected Option 1.

334 United Energy's response to IR020 question 14

335 Included as $4.7m in the RIN, which includes real cost escalation

336 United Energy BUS 7.05 - Network management, page 4

Table 7.17: Options summary – United Energy Network management systems - $m, real 2021

Option	Capex	PV capex	Risk
0 - Do nothing - do not upgrade, maintain current software versions in relation to our network management systems.	0.0	n/a	50.3
1 - Refresh current suite of network management systems - Perform prudent technical upgrades to maintain core currency and regulatory compliance, whilst targeting alignment and simplicity	24.9	22.9	13.4
2 - Replace the network management systems with alternative solutions	50.4	46.8	13.4

Source: UE BUS 7.05 Table 1 and UE MOD 7.07

Our assessment

Option 0 is not consistent with good industry practice

943. United Energy'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'[337] for core systems/applications. The most significant risk arises from systems not being supported by the vendors[338] or alternative third-party suppliers. United Energy 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 $50.3m, arising primarily from the risk of non-compliance. Whilst we have some issues with the input assumptions underpinning the monetised risk,[339] 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

944. Option 2 as described by United Energy involves replacing the network management systems with alternative solutions which provide similar functionality. United Energy states that *'[t]his option would involve significant organisational and technology change. Considerable changes to operational business processes would introduce an increased risk of interruptions to network operations/performance. This in turn would 'impact on supply reliability, safety and customer service.'*[340]

945. United Energy 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 of refreshes and upgrades are a fraction of the option 2 cost of installing new systems.

946. It is clear from the information provided by United Energy[341] and from our own experience, that the benefits of Option 2 are unlikely to outweigh the higher cost in any reasonable assessment.

337 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

338 That is, beyond published end-of-support dates

339 E.g. 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

340 United Energy BUS 7.05 - Network management, page 17

341 Including the description of the disadvantages of Option 2 in Table 9 of United Energy BUS 7.05 - Network management

947. We note that United Energy also considered a variation of Option 2 in which a subset of systems would be replaced with alternatives. Like United Energy, we consider this sub-option to be inferior to Option 1 because of integration-related issues.

United Energy does not discuss the option of cloud migration in the business case

948. United Energy'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 (UE BUS 7.10). In response to our question, United Energy advises that its OT applications are '*not considered eligible for cloud migration and will therefore remain on premise.*[342]

949. It is not clear from the response how cloud migration fits into the OT vendors' plans for the future; however, we infer from United Energy'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

950. The figure below shows United Energy's network management systems roadmap which identifies multiple upgrades and refreshes during the course of the next RCP. Whilst we acknowledge that building up significant technology debt is not commensurate with good industry practice, the frequency of system upgrades and refreshes appears to be excessive.

951. We discussed our concern with United Energy at our meeting with them. In summary, its feedback was consistent with its forecasting approach described in the business case which is that: (i) timing is based on vendor product support schedules and historical 5 year infrastructure replacement cycle; and (ii) forecast costs are based on historical costs.

952. In our review of United Energy's Market Systems business case, discussed in section 7.6.2, we note that it 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'.*[343] We consider that this 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 United Energy regarding its Network management systems.

953. United Energy's proposed annual average capex for the next RCP is $1.2m (30%) higher than expected Network management systems expenditure in the current RCP.[344] Some of the increase may be due to the SAP/HANA integration task; however, the extent of the difference is not explained satisfactorily.

954. We therefore remain concerned about the prudency and efficiency of the proposed upgrade cycle because the value of each upgrade may not be realisable.

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[342] United Energy response to IR020, question 14(b)

[343] United Energy BUS 7.06 – Network management, page 5

[344] United Energy response to IR020, question 4 based on data provided for 2016-2019

Figure 7.12: United Energy network management systems roadmap

System	Product	2021/22	2022/23	2023/24	2024/25	2025/26
Network Management Core						
SCADA DMS/OMS	Mosaic NMS	NMS Upgrade	Mosaic Upgrade		NMS Upgrade	Mosaic Upgrade
Supply Quality	Sensor IQ	Upgrade				Upgrade
Switching	NARS – Network Access Request System	Upgrade	Upgrade			Upgrade
Protection Systems	Schneider Electric ION			Upgrade		
Network Geospatial						
GIS	Smallworld CORE		Upgrade	S4HANA Integration		Upgrade
GIS Network Viewer	Smallworld Network Viewer+	Maintenance Release	Upgrade	Maintenance Release	Maintenance Release	Upgrade
Network Reporting and Analytics						
Outage Reporting	Oracle Utilities Analytics	Upgrade			Upgrade	
Network Data Processing	Future Grid PostgreSQL	Maintenance Release	Maintenance Release	Maintenance Release	Maintenance Release	Maintenance Release

Source: United Energy BUS 7.05 Network Management, Appendix C

Summary of our assessment

955. We remain unconvinced of the prudency and efficiency of United Energy's proposed frequency of upgrades/refreshes given the 30% uplift in average annual capex from the current RCP and the overall frequency of upgrades and refreshes. Our analysis suggests that an amount 10-15% less than proposed is likely to represent an efficient level.

7.6 Observations on remainder of proposed ICT capex

7.6.1 5 Minute Settlement (Non-recurrent)

956. United Energy's business case provides the supporting information for its proposed incremental opex, Non-recurrent ICT capex, and augex for communications devices to meet its 5-minute settlement compliance obligations.[345] We have made observations regarding all three expenditure components in this section.

Overview of the proposed project

957. Any Victorian smart meter installed after December 2018 must have the capability to record five-minute interval energy data by 31 December 2022. United Energy advised that its ICT systems do not currently comply with the relevant changes to the Rules. To resolve this compliance issue, United Energy proposes $17.7m in ICT capex, $3.9m in incremental opex and $3.4m in network communications capex, for total capex of $25.0m.

Our observations

Obligations must be met by 31 December 2022

958. United Energy 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.

[345] AEMC, Rule determination, National Electricity Amendment (Five Minute Settlement) Rule 2017

IT systems upgrade costs are based on relatively old information

959. To manage the expected increased volume of data that United Energy is responsible for under the five-minute settlement rule change, United Energy has identified that it will need to:[346]

- 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.

960. United Energy advises that 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.

961. United Energy's labour time estimates are based on historical costs, referring to its metering contestability project in 2017 and its IT systems upgrade project to accommodate AMI meters in the AMI roll-out.[347]

962. Whilst using historical costs is typically a reasonable starting point for cost estimation, recency of the information is fundamental to achieving a reasonable estimate. Given the quantum of capex involved 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 assumptions. The labour rates are based on information provided by PwC (per UE MOD 12.02), which should be a reasonable source.

963. We would expect that benchmarking of the unit costs and the capex and opex per customer for United Energy and the other 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

964. United Energy has provided a breakdown of the volume and unit costs assumed in its forecast for increasing the WAN and data processing capacity. United Energy leverages off recent unit costs and they appear to be reasonable.

Communication network costs appear to be reasonable

965. United Energy has estimated the capex for additional communications devices by: (i) identifying the four types of devices required; (ii) estimating 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) applying unit rates derived from recent costs.[348]

966. This approach seems reasonable. United Energy has provided a cost model with a detailed breakdown of components of the unit cost and the volumes of devices.[349] The cost model differentiates between the communications devices required for 5-minute settlement obligations and for its other related projects including the 3G-shutdown and for its annual repex program. There appears to be no overlap or duplication of costs. The communications network costs therefore appear to be reasonable estimates.

Opex step change approach appears to be reasonable

967. United Energy 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

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346 United Energy BUS 7.09 5 minute settlement, page 10

347 United Energy BUS 7.09 – 5 minute settlement, page 14, 19

348 United Energy BUS 7.09 5 minute settlement, page 19

349 UE MOD 6.03 – AMI comms

between IT systems; and (ii) to manage the increase in manual validations of meter data exceptions.

968. United Energy 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 to be reasonable. A step change is evident in its forecast from 2022/23 onwards.[350]

Summary of our observations

969. With the exception of the lack of compelling information to support the cost estimate for IT systems upgrades, our observations suggest that United Energy's approach and estimated cost to meet its 5-minute settlement obligation seems reasonable.

7.6.2 Market Systems (Recurrent)

Project overview

970. United Energy proposes to invest $7.4m in the next RCP on maintaining the currency of its market systems (which provide storage and validation of meter reading data and manage market-compliant communications and customer requests). United Energy 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	PV 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.	6.5	5.9	89.3
1 - Prudent technical upgrades - remain within vendor support by adopting every second software version release upgrade	7.4	6.8	21.4
2 - Vendor released technical upgrades - perform system upgrades as released by vendors, maintaining pace with newest available versions as they are released	12.3	11.3	3.0

Source: CP BUS 7.06, Table 1

Observations

971. 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.*'[351]

972. Unlike Option 2, Option 1 extends asset life beyond the vendors' recommended upgrade timelines at what United Energy considers to be acceptable risk levels, by delaying upgrades and associated costs until necessary. United Energy refers to this as an 'N-1' strategy. United Energy also advises that whilst '*its vendors will continue to support the previous version (N-1) of its market systems, they will not support prior versions (N-2 or earlier).*'[352]

973. 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.

350 United Energy BUS 7.09 5 minute settlement, Table 9

351 United Energy BUS 7.06 Market systems, page 19

352 United Energy BUS 7.06 Market systems, pages 12

Figure 7.13: United Energy's Market Systems currency roadmap

Source: UE BUS 7.06 – Market systems, Figure 3, page 22

974. United Energy's average annual market systems capex in the current RCP (2016-2019) was $1.1m, whereas its forecast annual average capex for the next RCP is $1.5m. This represents an increase of +32%, noting that the 2020 expected capex has not been provided.

7.6.3 Business Intelligence and Warehousing (Recurrent)

975. 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

976. 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 project - $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 United Energy, 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 United Energy, Powercor and one for United Energy.	8.3

Source: UE BUS 7.03 BI BW, Table 1, p4

Our observations

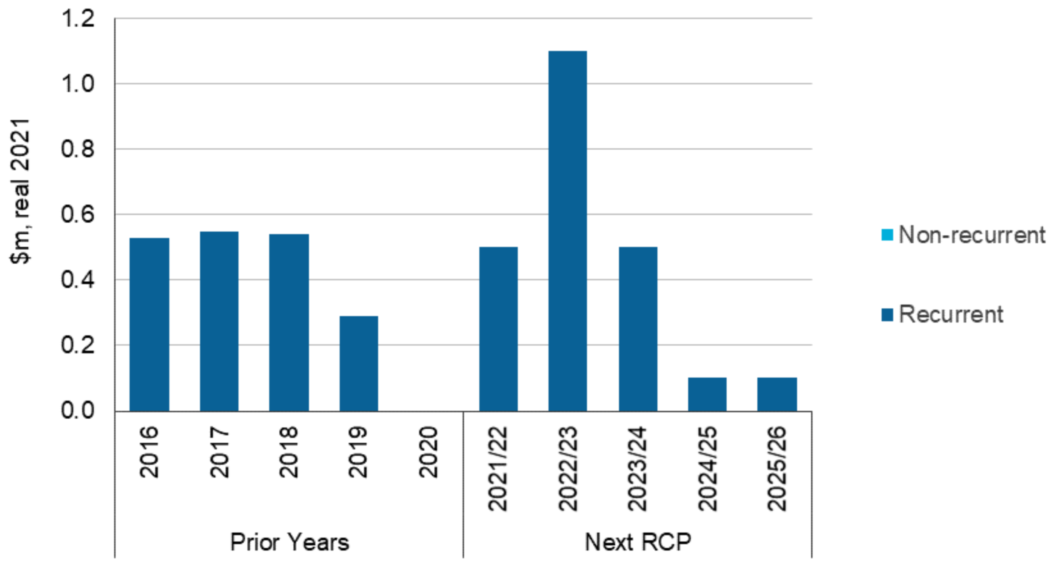
977. Option 0 is not consistent with good industry practice.

978. 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. Consolidating on an integrated common Data Lake platform as a foundation to a consolidated Enterprise Data Warehouse & Analytics platform is the recommended approach. We agree that this appears to be a prudent approach. United Energy identifies a business risk due to having a single core data warehouse system and concludes that the benefits outweigh the risks.

979. As a crosscheck, we asked United Energy to provide the BI/BW 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 annual historical capex of $0.48m (2016-2019) for United Energy is only 4% higher than United Energy's forecast capex of $0.46m p.a. for the next RCP.

980. In the absence of any other information, the allocation to United Energy and the quantum of expenditure for the next RCP appears to be reasonable.

Figure 7.14: United Energy's historical and forecast BI/BW capex - $m, real 2021



Source: EMCa analysis of information provided in response to IR020 and UE BUS 7.03

7.6.4 Device replacement (Recurrent)

Project overview

981. United Energy proposes to invest $3.1m in the next RCP on maintaining the currency of its end-user devices.[353] United Energy considered three options as described in the table below and selected Option 1. United Energy states that '*this option would result in decreasing performance across the board, leading to higher operating expenditure, poorer network reliability and increased safety risks.*'[354]

[353] Computers, laptops, mobile phones and tablets, videoconferencing units, projectors and display screens.

[354] United Energy BUS 7.12 Device replacement, page 10

Table 7.20: United Energy - Options summary for Device replacement - $m, real 2021

Option	Capex
0 - Do nothing - do not replace devices	0.0
1 - Replace devices at end of useful life	3.1
2 - Replace the devices in bulk at the beginning of the period	4.3

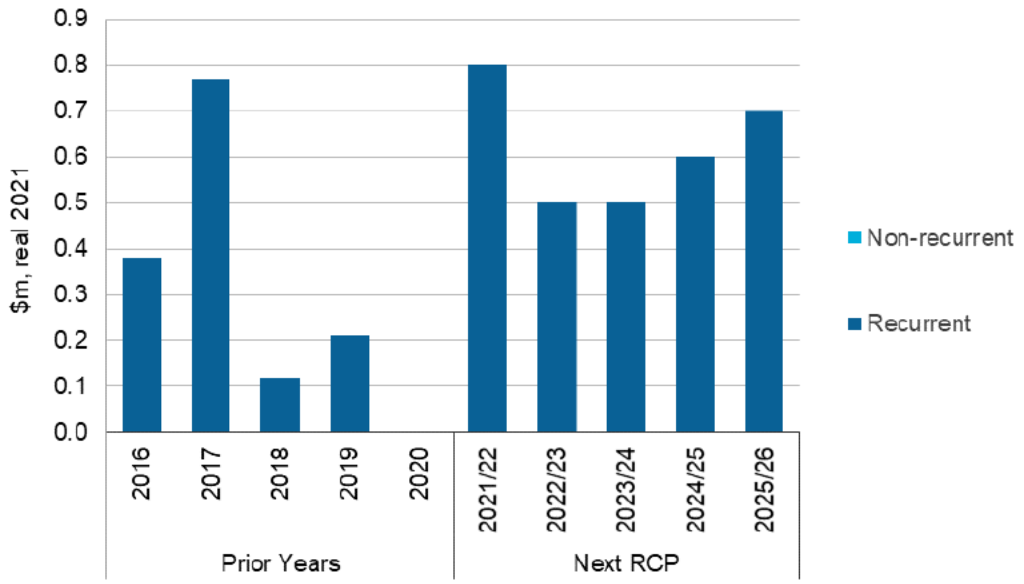
Source: UE BUS 7.12, Table 1 page 5

Our observations

982. Options 0 and 2 are not consistent with good industry practice. Option 2 is unlikely to add sufficient sustained net benefits as compared to Option 1.

983. With respect to Option 1, we asked United Energy to provide the device replacement capex for the current RCP,[355] 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 $0.4m p.a. compared to the forecast capex of $0.6m p.a. for the next RCP. United Energy does not explain the driver of this difference in its business case.

Figure 7.15: United Energy's historical and forecast Device replacement capex - $m, real 2021



Source: EMCa analysis of information provided in response to IR020 and PAL BUS 7.12

984. United Energy states that '[T]his option maintains current levels of operational performance by replacing devices based on end of useful life and ensuring new contact centre employees have the necessary devices to undertake their roles.'[356] We would therefore expect United Energy's capex forecast for the next RCP to be approximately $0.4m p.a. for a total of $2.0m, rather than the proposed $3.1m.

7.6.5 Enterprise management systems (Recurrent)

Project overview

985. United Energy proposes to invest $8.7m in the next RCP to maintain the currency of its Enterprise Management Systems (EMS) because:[357]

[355] United Energy response to IR020, question 4

[356] United Energy BUS 7.12 Device replacement, page 7

[357] United Energy BUS 7.11 EMS

- 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 7.4.5) is required; and
- Of changes in technology, customer requirements, and cyber security threats.

986. United Energy considered three options as shown in the table below and selected Option 1.

Table 7.21: United Energy's options summary – Enterprise management systems - $m, real 2021

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	8.7
2 - Transform – identify opportunities for transformation with the aim of unlocking larger benefits that could be passed on to customers (additional functionalities and efficiencies).	11.6

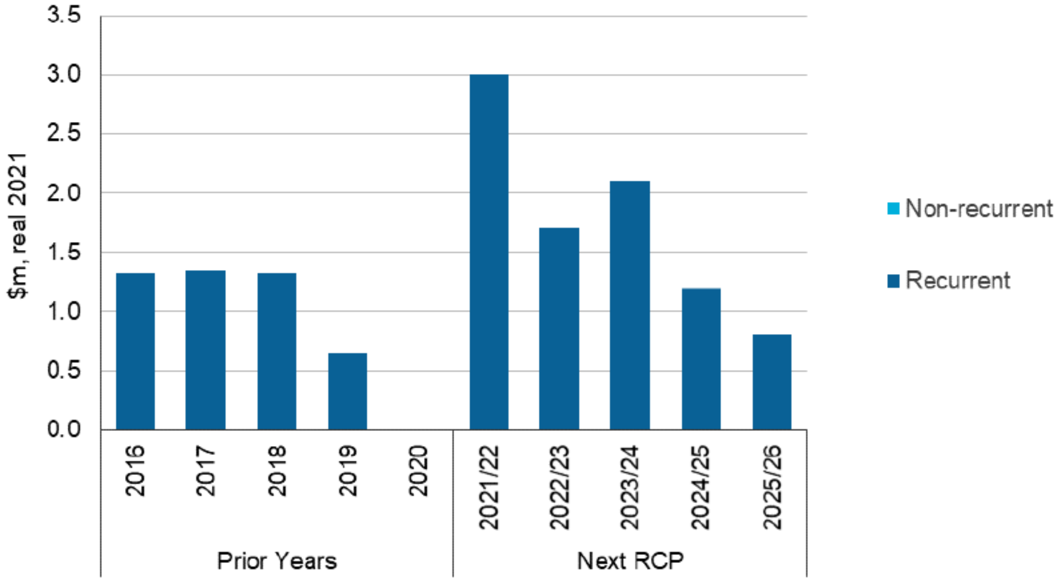
Source: UE BUS 7.11 EMS, Table 1

Our observations

987. Option 0 is not consistent with good industry practice. Option 2 is unlikely to add sufficient sustained net benefits as compared to Option 1.

988. We asked United Energy 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 annual average capex of $1.8m for the next RCP is approximately 50% higher than the $1.2m annual average capex over the period 2016-2019.

Figure 7.16: United Energy's historical and forecast Enterprise management systems capex - $m, real 2021



Source: EMCa analysis of information provided in response to IR020 and UE BUS 7.12
Note: Annual expenditure is based on format of data provided by United Energy

989. United Energy identifies the status of the 12 enterprise systems and its plans for each in Table 7 of the business case, which provides some confidence in United Energy's analysis.

990. United Energy 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.' We observe that what United Energy refers to as its 'N-1' strategy is likely to lead to more efficient costs than an N-0 or an N-2 strategy.

991. However, we observe that United Energy proposes approximately $2.3m capex in 2021/22-2022/23 on upgrading 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 section 7.4.5 and 7.5.2, respectively. Given that United Energy 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)

992. The forecast $4.7m ICT component of United Energy's Facilities security project is discussed in our review of property capex included in section 8.

7.6.7 General compliance (Recurrent)

Project overview

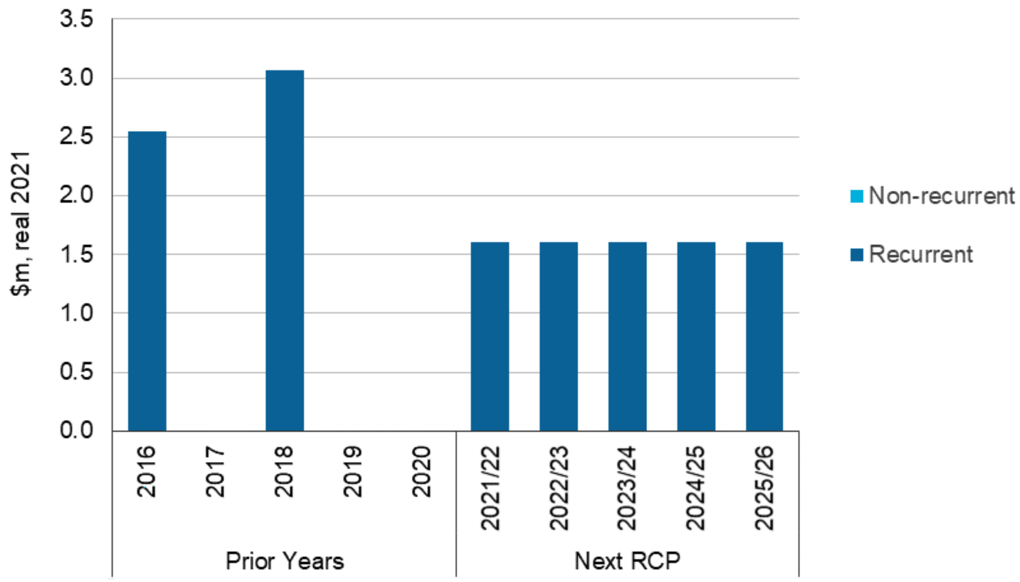
993. United Energy proposes spending $8.2m on 'General IT compliance' projects to meet anticipated obligations are periodically amended. United Energy advises that *'[w]e anticipate that during 2021–2026 there will be a similar trend in amendments to regulatory obligations we have seen over the current regulatory period.'*[358] United Energy considered two options – Do nothing and its preferred approach.

Our observations

994. We asked United Energy to provide its 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 2016-2019 is $1.4m, which is slightly lower than the proposed annual average of $1.6m p.a. for the next RCP.

[358] UE BUS 7.14, page 5

Figure 7.17: United Energy'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
Note: Annual expenditure is based on format of data provided by United Energy

7.6.8 Telephony (Recurrent)

995. 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: (i) their respective customer share; and (ii) United Energy bearing the full cost of integrating its contact centre with VPN's. Unless otherwise stated, our observations relate to the total costs and benefits attributable to VPN/UE.

Project overview

996. VPN/UE propose 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

997. 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.

998. 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 centres.*'[359] The quantum of savings is not identified in the business case or the model.[360]

[359] United Energy BUS 7.13 Telephony, page 12

[360] United Energy MOD 7.19 Telephony; no opex – either savings or expense – is identified in the model

999. 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.

1000. 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: (i) omni-channel capabilities; and (ii) faster customer identification through an interactive voice response (IVR) interface. VPN/UE claim that these features will:

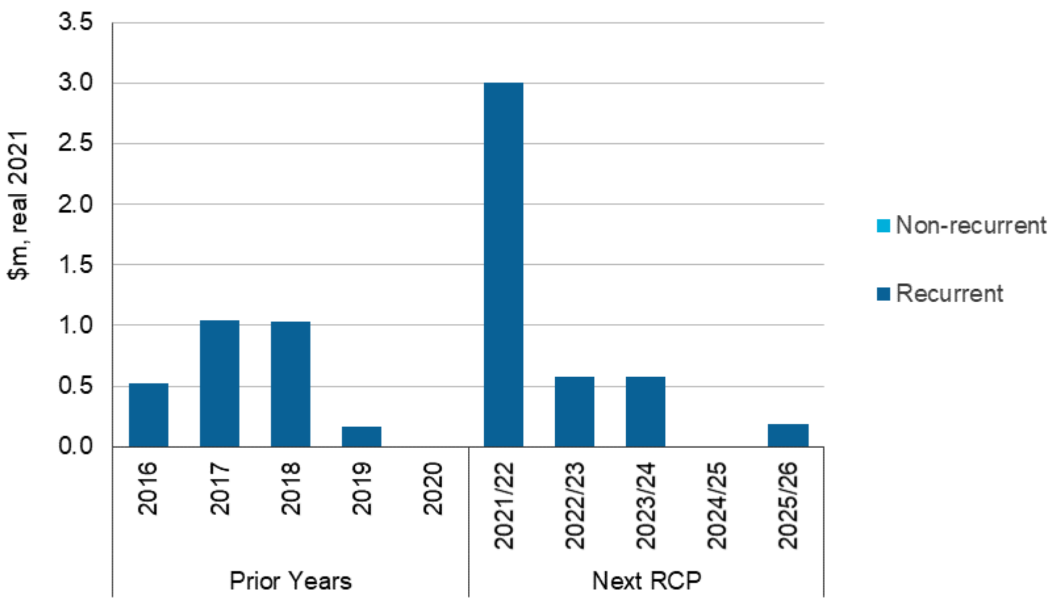
- Save customers a minimum of 1 minute each per annum and that this is sufficient to '*…ensure the investment is worthwhile*'; [361] and
- Provide a credible response to customer feedback: 'Around 80% of our customers across the three networks were interested in easier access to their data and information and enhances [sic] customer experiences.'[362]

1001. VPN/UE value a residential customer minute at about $0.18. 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 the estimate of how many customers will actually benefit from the new service. Therefore, it does not provide an NPV inclusive of benefits and infrastructure refresh costs.

1002. The cost estimate for the major components of Option 1 are based on recent upgrades and integration projects involving the three DNSPs, which is a reasonable approach.

1003. Referring to the figure below, the average annual United Energy expenditure in the current RCP is $0.7m p.a., whereas for Option 2 it increases to $0.9m p.a (+25%) over the next RCP. However, the increase is incurred mostly in 2021/22, after which opex averages less per annum than in the current RCP. This appears to be reasonable for United Energy's share of the additional Option 2 features.

Figure 7.18: United Energy historical and forecast Telephony capex - $m, real 2021



Source: EMCa analysis of information provided in response to United Energy's response to IR020 and UE BUS 7.13
Note: Annual expenditure is based on format of data provided by VPN

361 United Energy BUS 7.13 Telephony, page 15

362 United Energy BUS 7.13 Telephony, page 14

7.7 Summary of findings and implications for United Energy's ICT capex forecast

1004. We consider that United Energy's proposed capex on its ICT projects for the next RCP is above the level required by a prudent and efficient operator.

Selected options are typically appropriate

1005. 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 (that is – via a reduced scope). In a few other cases we suggest that, for completeness, another credible option should have been included in the analysis although we do not have reason to believe that they would be preferable to the selected option.

Some claimed benefits in Non-recurrent projects are over-stated

1006. For several projects with Non-recurrent expenditure, United Energy 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 regarding the longevity of some of the claimed benefit streams relied upon to generate a positive NPV for the project.

1007. For every business case for which a model was presented, we undertook sensitivity studies to test the robustness of the proposed quantum and timing of the proposed expenditure and to determine reasonable prospective negative variances. In some cases, such as Intelligent Engineering, we found that despite overstated benefits the project is still likely to be undertaken by a prudent operator. However, in other cases, we consider that the extent of expenditure is unjustified.

Approaches to the timing of recurrent expenditure varies between projects

1008. We consider that United Energy's 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 cases, we consider that unnecessary upgrades/refreshes are planned. We consider that this approach will incur unjustified capex and place at risk the organisation's capacity to efficiently absorb the change management workload and which, in turn, will threaten the value of the upgrade.

Change management risk to project delivery may be under-recognised

1009. In our opinion, business cases which promote the integration of VPN and United Energy systems such as consolidating on one platform and/or incorporating cloud hosting options are likely to provide long term net benefits (including beyond the next RCP). However, there is significant change management risk in such projects, and which may affect the delivery of the entire work program as proposed.

The ICT infrastructure cloud migration opex step change is reasonable, however the capex-opex trade-off has not been adequately justified by United Energy

1010. We consider that the proposed opex step change of $4.5m for United Energy to account for the increase in hosting charges resulting from the transition of ICT infrastructure to the cloud is reasonable. However, United Energy has not provided sufficient information to confirm that the capex for refreshing the remaining on-premise infrastructure is reasonable.

8 REVIEW OF PROPOSED BUILDINGS AND PROPERTY CAPEX

In this section, we present our review of United Energy's proposed buildings and properties capex, which almost entirely comprises depot developments (both new builds and redevelopments), with a much smaller amount proposed for facilities security upgrades.

We consider that the proposed security upgrade expenditure is reasonable.

We consider that the proposed new depot at Mornington is sufficiently justified for the purpose of including it in United Energy's capex allowance. We consider that an allowance for upgrade work is also justified for the Burwood and Keysborough depots, though at a lesser scope and cost than United Energy has proposed.

8.1 Overview of proposed buildings and property expenditure

1011. As shown in Table 8.1 below, United Energy proposes to spend a total of $71m (including real labour cost escalation) on buildings and property in the next RCP. This equates to an average of $14.2m per year, which is a significant increase compared with its expenditure in the current period of around $2m per year.[363]

Table 8.1: RIN category - Buildings and property capex - $m, real 2021

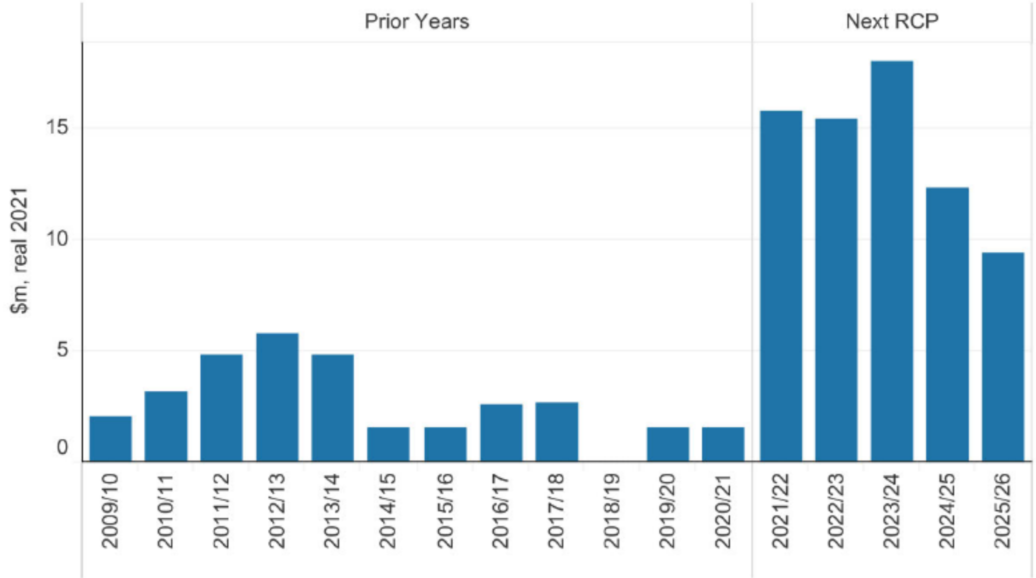
Asset Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Buildings and Property	15.8	15.5	18.0	12.4	9.4	71.0
Total	**15.8**	**15.5**	**18.0**	**12.4**	**9.4**	**71.0**

Sources: United Energy RIN001

1012. The graph below shows United Energy's expenditure trend from prior years (2009/10 – 2020/21) compared to the next RCP (2021/22 – 2025/26). It shows relatively steady expenditures of around $2m per year from 2014/15 to 2020/21. The significant increase in forecast expenditure for the next RCP is for the proposed depot developments.

363 Because of missing data for 2018/19, and the current period comprising 5.5 years, this is an approximation as we do not have the information for an exact comparison

Figure 8.1: Buildings and property capex trend graph - $m, real 2021



Source: United Energy RIN001 & RIN008. United Energy provided calendar year data of $3.0m for 2018 and $3.3m for 2019 (in $2021). 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.

1013. United Energy's disaggregation of its proposed expenditure excludes real cost escalation and amounts to $69.8m for the next RCP, with over 95% of the forecast being for its proposed depot upgrades and new builds. See Table 8.2 below for details.

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 security			0.9			0.9
Depot	15.7	15.3	16.7	12.1	9.1	68.9
Total Cost	**15.7**	**15.3**	**17.6**	**12.1**	**9.1**	**69.8**

Sources: UE MOD 8.02 and UE MOD 8.03

8.2 Review of proposed facilities security upgrades

8.2.1 Basis for United Energy's proposal

1014. United Energy submitted its Business Case (UE BUS 8.04) and options analysis models (UE MOD 8.03) to support its proposed expenditures. The Business Case and the model contain a Property component as described here and an ICT component which we assess in section 7.

1015. The proposed amount of $0.9m for next period is to upgrade existing CCTV camera in its depots.

8.2.2 Our assessment

1016. We reviewed United Energy's supporting documentation including its Cost Benefit Analysis (CBA) model. United Energy's proposal is supported by evidence of need from a Strategic Security Review and other documents attesting to the upgrades as being consistent with good industry practice regarding security and unauthorised access.[364] We consider that the proposed expenditure is reasonable.

8.3 Review of proposed depot upgrades and rebuilds

8.3.1 Overview of United Energy's proposal and justification

Proposed sites and costs

1017. United Energy proposes to spend $68.9m[365] for upgrading and building depots on new sites for the next regulatory period (2021/22 – 2025/26).

Table 8.3: United Energy's proposed expenditure on depot upgrades and rebuilds - $m, real 2021

Depot Location	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Mornington	0.0	0.0	0.0	6.4	9.1	15.6
Burwood	15.7	15.3	0.0	0.0	0.0	31.0
Keysborough	0.0	0.0	16.7	5.6	0.0	22.3
Grand Total	**15.7**	**15.3**	**16.7**	**12.1**	**9.1**	**68.9**

Source: EMCa analysis of UE MOD 8.02.

1018. The works and associated drivers for proposed depot upgrades and rebuilds as summarised by United Energy in its Regulatory Proposal[366] are described below:

- **Mornington:** *'We will purchase a replacement site and construct a new depot in Mornington that is fit-for-purpose to adequately service the region. There are a number of issues with the current site, providing limited opportunity to adapt the depot for our requirements in the future. The current site was purchased in 1994 and was previously operated as a Telstra depot. The last capital improvements to the site were completed approximately 15 years ago and it is no longer fit-for-purpose. The current office facilities consist of portable units that are approaching end-of-life. In addition, there is a lack of suitable storage and yard space making it difficult to service on-site fleet vehicles. There is little ability to further develop the site as existing ground conditions provide limited opportunity to expand into neighbouring sites. The site also is not close to major arterial roads, which will make it increasingly difficult to service the region over time as greater demands are placed on the network and as roads become more congested due to continued population growth;'*
- **Burwood:** *'We will upgrade and optimise our depot in Burwood. Land in this area is at a premium making the cost of moving to a new site inefficient. We will instead ensure we maximise our current depot site by redeveloping it and moving staff to temporary accommodation during the rebuild. The proposed works are significant as the buildings at this site were constructed in the 1980s with no major capital improvements undertaken since that time. As a result, the depot is severely dated and suffers from legacy maintenance requirements, which fail to maximise the available storage space for materials. Work is also required to adapt part of the site previously used by MultiNet Gas to make it fit-for-purpose and to ensure efficient and safe traffic flow;'*
- **Keysborough**: *'We will upgrade and expand our depot in Keysborough. We are already starting to reach space constraints at this site and have begun leasing adjacent land as a result. This will become more expensive over time as land values increase as a result of population growth in the area. We therefore plan to purchase this adjacent*

[364] United Energy references these documents on page 4 of its Business Case (UE BUS 8.04)

[365] Excludes real cost escalation

[366] United Energy – regulatory proposal – 31 January 2020 p. 133

land so that we have sufficient space to continue to service the region over the long term while also safeguarding cost efficiency. In addition, the current depot site is severely dated with the original 1960s interior and infrastructure remaining.'

United Energy's business cases and other documentation

1019. United Energy provided business cases for each of the three proposed depot redevelopments. Each business case includes some background information on the depot, a statement of 'identified need', a description of the treatment options considered including their costs, a brief summary of advantages and disadvantages, and a recommendation.

1020. In response to an information request (IR03), United Energy also provided budget estimates from a project and construction management firm for development of the new depot at Mornington,[367] but not for the Keysborough nor Burwood depot redevelopments.

Cost benefit analysis (CBA)

1021. In response to an information request (IR003), United Energy submitted CBA models in which it analysed the present value cost (PV cost) of each option for all depots. For most sites, United Energy considered five options:

- Option 0: Do nothing;
- Option 1: Redevelop existing site;
- Option 2: Develop 'Greenfields site';
- Option 3: Purchase 'brownfields' site; and
- Option 4: Minimum spend.

1022. United Energy presented its analysis in terms of the Net Present Cost of each option. All options included what are effectively risk costs, such as we describe below. Options other than '*Option 0: Do Nothing*' also include the capital cost of the proposed development. By comparing these to determine the option with minimum NPC, United Energy is effectively treating the reduced risk costs of the upgrade options (i.e., relative to the 'do nothing' counterfactual) as benefits.

1023. United Energy uses assumptions in the models to derive PV costs for the following factors, to the extent each is relevant to the particular depot and upgrade option:

- Costs of inadequate storage;
- Costs of outdated facilities;
- Costs of not addressing structural issues;
- Costs of inadequate depot capacity;
- Costs of not addressing safety risks; and
- Costs of suboptimal depot location.

8.3.2 Assumptions in United Energy's cost benefit analysis

Key assumptions in its CBA are not evidenced and some assumed benefits appear overstated

1024. We reviewed United Energy's CBA models including the assumptions used. We sought further information on the basis for the 'benefit' assumptions, which effectively derive from the difference between the assumed costs if nothing is done, compared with lower assumed costs if upgraded. However, United Energy did not provide evidence or other sources for the assumptions that it has made.

1025. We observe that the CBA is very sensitive to the relative cost assumptions between doing nothing and the proposed upgrade. Our specific observations are set out below.

[367] UE ATT IR003 – Mornington depot quote - Public

- **Productivity assumption:** The United Energy analysis makes assumptions regarding productivity improvements arising from factors such as ‘inadequate storage’ and ‘substandard facilities’. These are additive in United Energy’s model, such that increases in productivity are assumed to occur for each factor and it could be that there is an element of duplication. For example, in the Mornington CBA, United Energy assumes productivity improvements for 38 personnel arising from five different factors of 1.0%, 1.5%, 5%, 5% and 2.5% - therefore with an implied aggregate productivity improvement of 15%. These assumed percentage improvements are not supported by evidence or cross-checked, for example, from experience which could have come from the five similar upgrades and rebuilds that its partner business Powercor is undertaking in the current period.
- Using United Energy’s assumptions, we calculate that the upgrades imply a $14.6m opex productivity benefit, taken over all of the depots over the next RCP. This should manifest as a benefit realisation through the ability to reduce staff numbers. However, United Energy does not show evidence of having considered this, and which could have been a reasonable top-down ‘sense-check’ on the assumptions.
- **Safety risk assumption:** Similarly, by way of a cross-check, we calculated the risk of a depot-related fatality using United Energy’s risk assumptions. We find that those assumptions imply a current state probability of a depot-related fatality occurring of 45% for the next RCP. We consider it to be extremely unlikely that United Energy would be currently operating depots with safety risk levels this high. We consider it more likely that either the risk is not as high as United Energy’s assumptions in its CBA or that the risk could be reduced considerably through mitigation measures with a lesser scope than building a new depot or rebuilding an existing depot.
- **Customer service assumption:** We observe that United Energy has accounted for reduced customer Unserved Energy costs arising both from ‘inadequate depot capacity’ as well as from ‘inadequate storage’. Further, the percentage improvements are not supported by evidence, which we consider could have been obtained from benefits realisation assessment from previous rebuilds undertaken by Powercor. The additive treatment of these two factors raises the possibility of duplication.

1026. We tested the sensitivity of United Energy’s resulting analysis by modifying assumptions in the model. Primarily, we removed what could be considered ‘duplicated’ factors as above and, for safety risks, we introduced a ‘Probability of Consequence’ factor of 10% on the basis that not each ‘major safety incident’ would necessarily result in a fatality. We also reduced other probabilities that had been entered without supporting evidence. The purpose of doing so is to ‘stress-test’ the net benefits of the proposed upgrades and rebuilds and to assess whether United Energy’s choice can be considered sufficiently robust.

8.3.3 Cost estimation

1027. United Energy provided cost estimation for its proposed Mornington, Burwood and Keysborough depots and which were prepared by B2B Project and Construction Management.

1028. We observe disaggregated budgets that appear to be specific to the requirements. The amounts tally with the amounts that United Energy has proposed (when contingencies are excluded). We consider that the cost estimations for these depots provides a reasonable basis for determining allowances.

8.3.4 Development of new depot in Greenfield site in Mornington

Basis for United Energy's proposal[368]

1029. United Energy states in its business case that the existing Mornington depot lacks adequate material storage and has severely dated office buildings, poor traffic flow throughout the site and a lack of proximity to major arterial roads.

1030. Further, United Energy believes that by 'not upgrading the site would result in detrimental impacts on:

- operational performance - including ongoing and escalating reductions in workforce productivity due to the lack of materials storage and poor traffic flow, particularly in high fault weather events;
- future network reliability as workload growth driven by growth on the Mornington peninsula cannot be accommodated, particularly given the sub-optimal site location relative to growth through the growth in the southern end of the peninsula, from Rosebud to Sorrento; and
- workforce, diversity and health and safety standards - buildings are compliant with relevant historic standards, but not with current standards or codes. See attachment UE ATT057 - Legal obligations property - Jan2020 - Public for further information about our legal obligations relating to building standards, occupational health and safety and equal opportunity.'

1031. To support the proposed expenditure, United Energy undertook five options analyses including a 'Do Nothing' option in response to our Request for Information (IR003).

1032. We reviewed and assessed the model and made some adjustments which we believe are reasonable.

Our assessment

The CBA supports United Energy's business case to develop a new depot in Mornington

1033. In its Business Case and CBA model, United Energy presents five options with input assumptions as discussed above. As shown in Table 8.4, the PV results combined with United Energy's assumptions show that developing a new depot on a greenfield site has a lower PV cost compared with the other options. Our sensitivity assessment supports United Energy's assessment.

Table 8.4: Option analysis for depot at Mornington - $m, real 2021

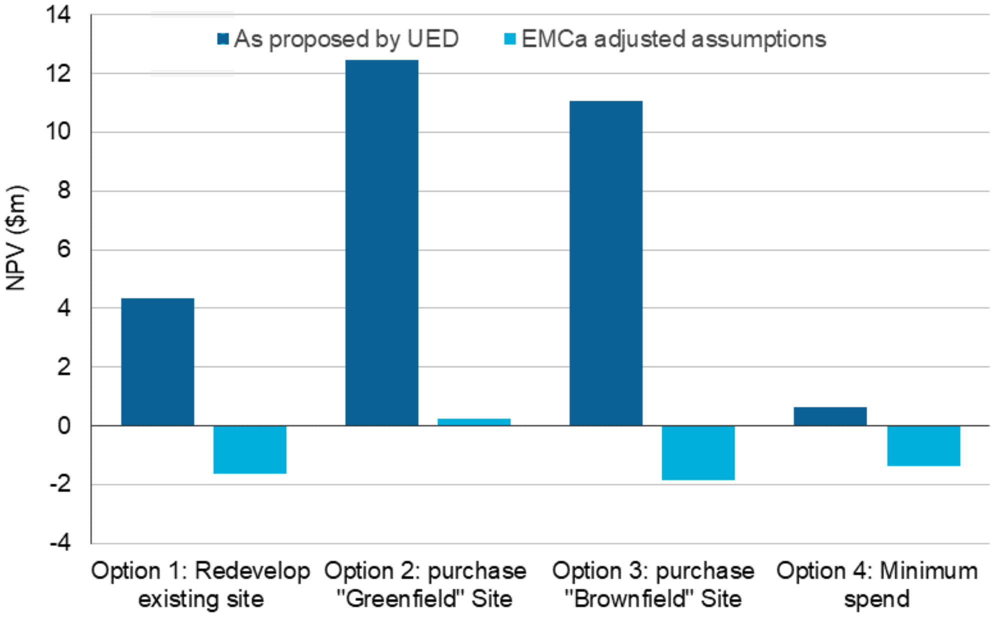
Description of option - Ballarat	Undiscounted capex	PAL PV cost	PAL Ranking	EMCa PV cost	EMCa Ranking
Option 0: Do nothing	0.0	35.8	5	19.1	2
Option 1: Redevelop existing site	12.2	31.4	3	20.8	4
Option 2: purchase "Greenfield" Site	**15.5**	**23.3**	**1**	**18.9**	**1**
Option 3: purchase "Brownfield" Site	12.8	24.7	2	21.0	5
Option 4: Minimum spend	9.0	35.1	4	20.5	3

Source: EMCa table derived from UE MOD IR003(c) – Mornington depot

1034. As can be seen in Figure 8.2, our NPV analysis with de-rated benefit assumptions indicates that developing a new depot on a greenfield site in Mornington still has a slightly positive NPV while all other options have a negative NPV. We consider that the proposed expenditure by United Energy for Option 2 is reasonable.

368 Summarised from UE BUS 8.03

Figure 8.2: NPV analysis for Mornington depot - $millions



Source: EMCa table derived from UE MOD IR003(c) – Mornington depot

8.3.5 Upgrade existing depot at Burwood[369]

Basis for United Energy's proposal

1035. United Energy states that the existing depot has a suboptimal layout which fails to efficiently optimise office space and to maximise the available storage space for housing adequate stocks of materials. It requires significant upgrades due to the lack of adequate material storage, severely dated buildings and poor traffic flow throughout the site.

1036. United Energy believes that 'not upgrading the site would result in detrimental impacts on:

- operational performance including:
  - escalating adverse impacts to our workforce's ability to carry out duties due to the lack of materials storage and poor traffic flow;
  - future impacts on network reliability as workload growth cannot be accommodated due to site congestion; and
- workforce, diversity and health and safety standards - buildings are compliant with relevant historic standards, but not with standards required should the depot be built in the present day. See attachment UE ATT057 - Legal obligations property - Jan2020 – Public for further information about our legal obligations relating to building standards, occupational health and safety and equal opportunity.'

Our assessment

The CBA does not support United Energy's business case to redevelop the existing Burwood site with the scope and cost that United Energy has proposed

1037. In its Business Case and CBA model, United Energy presents five options with input assumptions as discussed above. The PV results combined with United Energy's assumptions show that redeveloping the existing site at Burwood has a significantly lower PV cost compared with the do nothing counterfactual. However, our sensitivity assessment indicates a lower PV cost for Option 4 (minimum spend) and does not support United Energy's assessment.

369 Summarised from UE BUS 8.01

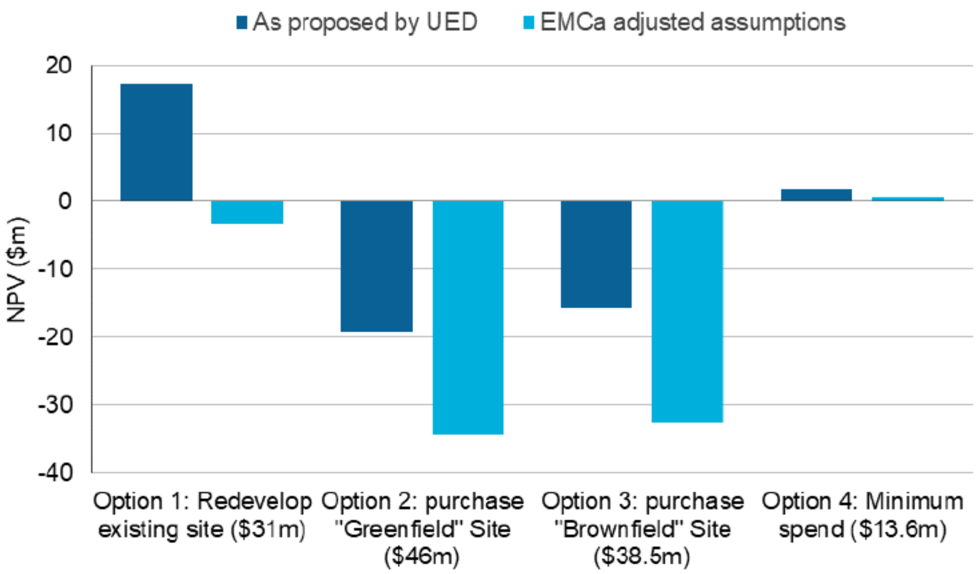
Table 8.5: Option analysis for proposed depot at Burwood - $m, real 2021

Description of option	Undiscounted capex	PAL PV cost	PAL Ranking	EMCa PV cost	EMCa Ranking
Option 0: Do nothing	0.0	50.6	3	30.1	2
Option 1: Redevelop existing site	31.0	**33.3**	**1**	33.3	3
Option 2: purchase "Greenfield" Site	46.0	69.8	5	64.4	5
Option 3: purchase "Brownfield" Site	38.5	66.3	4	62.6	4
Option 4: Minimum spend	13.4	48.8	2	**29.4**	**1**

Source: EMCa graph derived from UE MOD IR003(b) – Burwood depot

1038. The result in Figure 8.3 shows the NPV of each of the development options relative to the 'do nothing' counterfactual, both under United Energy's assumptions and with our more conservative sensitivity assumptions. It shows that, using de-rated benefit assumptions as described above, all options would have a negative NPV except for the 'Minimum spend' option. Based on the information that United Energy has provided, our assessment therefore indicates concerns with the option that United Energy has proposed to address the issues at this site.

Figure 8.3: NPV analysis for depot at Burwood - $millions



Source: EMCa graph derived from UE MOD IR003(b) – Burwood depot

1039. On a strict reading of our analysis results with adjusted assumptions, the minimum spend option ranks higher than the proposed redevelopment and has a positive NPV (relative to 'do nothing'). We observe that the minimum spend option is also the second-ranked option under United Energy's own analysis.

1040. We consider that United Energy has not presented a sufficiently robust case to justify its proposed redevelopment. However, with our de-rated benefit assumptions, the difference in NPV between minimum spend (option 4) and United Energy's redevelopment proposal (option 1) is relatively small. If a redevelopment could be undertaken to achieve all, or almost all, of the intended benefits at around 10% lower cost than United Energy has proposed, then this could become the preferred option.

8.3.6 Upgrade and expand existing depot at Keysborough

Basis for United Energy's proposal[370]

1041. Similar to the reason for the proposed depot redevelopment at Burwood, United Energy states that the existing Keysborough depot requires significant upgrades due to the lack of adequate material storage, severely dated buildings and poor traffic flow at the site.

1042. United Energy considers that not upgrading the site would result in detrimental impacts on:

- 'operational performance including ongoing and escalating adverse impacts to our workforce's ability to carry out duties due to the lack of space and future impacts on network reliability as workload growth cannot be accommodated;
- depot security with consequential increasing risks of theft and threats to public and worker safety; and
- workforce, diversity and health and safety standards. Buildings are compliant with relevant historic standards, but not with standards required should the depot be built in the present day. See attachment UE ATT057 - Property regulatory obligations and requirements - Jan2020 - Public for further information about our legal obligations relating to building standards, occupational health and safety and equal opportunity.'

Our assessment

The CBA does not appear to support a business case to upgrade and expand the current depot at Keysborough with the scope and cost that United Energy has proposed

1043. In its Business Case and CBA model, United Energy presents five options with input assumptions as discussed above. The PV cost of the options with United Energy's assumptions shows that its 'Option 2' has the lower PV cost compared with the 'do nothing' counterfactual. However, our assessment shows how sensitive this result is to the assumptions that United Energy has chosen, and the de-rated benefit assumptions would lead to 'Minimum spend' being preferable to expanding and redeveloping the current depot at the scope and cost that United Energy has proposed.

Table 8.6: Option analysis for proposed depot at Keysborough - $m, real 2021

Description of option	Undiscounted capex[371]	PAL PV cost	PAL Ranking	EMCa PV cost	EMCa Ranking
Option 0: Do nothing	0.0	64.0	5	32.8	3
Option 1: Redevelop existing site	20.5	50.5	3	32.8	4
Option 2: Expansion/develop current depot	22.3	**35.2**	**1**	30.9	2
Option 3: Purchase "Brownfield" Site	35.5	46.2	2	41.8	5
Option 4: Minimum spend	9.0	60.0	4	**28.6**	**1**

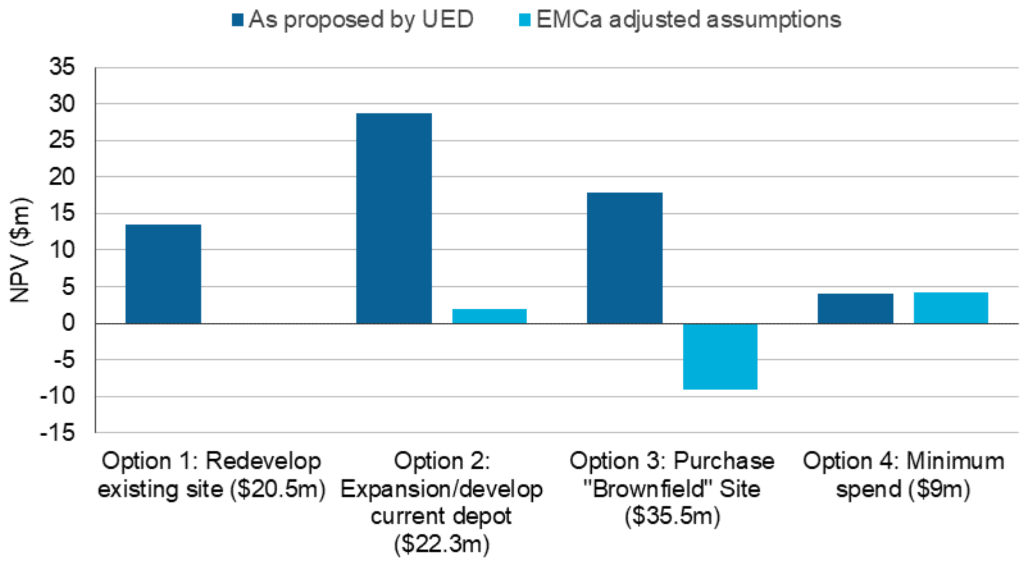
Source: UE MOD IR003(a) – Keysborough depot

1044. In Figure 8.4 below we show the NPV of each of the upgrade options, relative to the 'do nothing' counterfactual. With more conservative assumptions, the preferred option by United Energy (option 2) has approximately half the NPV of the preferred option (option 4) as determined through our analysis.

370 Summarised from PAL BUS 8.04

371 Excludes real cost escalation

Figure 8.4: NPV analysis for proposed depot at Keysborough - $millions



Source: UE MOD IR003(a) – Keysborough depot

1045. As with United Energy's proposed Burwood redevelopment, on a strict reading of our analysis results with adjusted assumptions, the minimum spend option for Keysborough ranks higher than the proposed redevelopment and has a positive NPV.

1046. We consider that United Energy has not presented a sufficiently robust case to justify its proposed redevelopment. However, with de-rated benefit assumptions, the difference in NPV between minimum spend (option 4) and United Energy's redevelopment proposal (option 1) is relatively small. If a redevelopment of Keysborough depot could be undertaken to achieve all, or almost all, of the intended benefits at around 10% lower cost than United Energy has proposed, then this could become the preferred option.

8.4 Findings and implications

8.4.1 Findings summary

Facilities security upgrades

We consider that the proposed expenditure for facilities security upgrades is reasonable

1047. We consider that United Energy's proposal to upgrade security at its 'high risk' substations is justified.

Depot redevelopments

The proposed new Mornington depot is reasonable

1048. We consider that United Energy has made a reasonable case for proposed development of a new depot at a new greenfield site in Mornington. We consider that the proposed costs are reasonable.

Upgrade work is required at the Burwood and Keysborough depots, though with reduced scope and cost relative to United Energy's proposal

1049. On the information provided by United Energy and our review of the assumptions made, we consider that there is not a sufficient business case to justify upgrade of the Burwood depot or the redevelopment and expansion of the Keysborough depot at the scope and cost that

United Energy has proposed. We consider that United Energy has made a sufficient qualitative case for upgrade work to be undertaken at both sites within the next RCP, whether by way of a ‘minimum spend’ option that defers the need for upgrades or some form of reduced scope redevelopment that will achieve the majority of benefits at a lower cost.

9 REVIEW OF PROPOSED OPEX STEP CHANGE FOR MINOR REPAIRS

In this section, we consider an opex step increase proposed by United Energy for reclassifying certain repair costs as 'minor repairs opex' that it previously classified as repex.

We consider that United Energy has, for the most part, reasonably described the nature of the work as supported by historical information. However, we consider that the nature of some proposed items do not meet the definition of a 'minor repair'.

Accordingly, we consider that a reasonable allowance would be a lower amount than United Energy has proposed.

9.1 United Energy's proposal

1050. Starting from the next RCP, United Energy proposes to reclassify expenditure for what it refers to as 'minor repairs' as opex. United Energy has proposed an opex step increase of $26.2m as part of its Base Step Trend (BST) based opex forecast, as shown in Table 9.1.[372] United Energy currently capitalises this expenditure as repex.

Table 9.1: United Energy proposed opex step increase for reclassification of minor repairs opex - $m, real 2021

Item	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Minor Repairs	5.2	5.2	5.2	5.2	5.2	26.2
Total	**5.2**	**5.2**	**5.2**	**5.2**	**5.2**	**26.2**

Source: EMCa analysis from UE RIN001

1051. United Energy proposes justification as follows:[373]

> *"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 propose to adjust our base year operating expenditure for the total cost of minor repairs in 2019 and removed forecast minor repairs from our capital replacement expenditure forecast. These changes are net present value neutral, which means customers are no worse-off in the long term."*

[372] United Energy 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

[373] United Energy Regulatory Proposal, page 153

1052. United Energy also provided a workbook in which it had recast historical repex which it considers would have fit into the new minor repairs classification as opex,[374] and its new proposed Cost Allocation Methodology.[375]

9.2 Our assessment

9.2.1 Approach to our assessment

1053. In undertaking our assessment, we have considered the following three factors:

- In order to accept a reclassification such as United Energy has proposed, we consider that it is necessary to first have 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 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 while capitalising the relevant expenditure for inclusion in the Regulatory Asset Base (and subsequent recovery through returns and depreciation).[376]
- Secondly, we sought to understand the nature of the work that United Energy is proposing to classify.
- Thirdly, if we were to propose accepting the reclassification as an opex step change, it is necessary to have 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

1054. In its 2020-2025 Regulatory Proposal, SAPN proposed a similar 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.

1055. 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*

[374] United Energy IR019 – Category Analysis RIN 2019 – Recast May2020 - Confidential

[375] UE ATT124 – Cost Allocation Methodology – Jan2020 - Public

[376] These effects would be moderated however by the impact of the efficiency carry-over incentives and penalties arising from the EBSS (for opex) and the CESS (for capex) respectively.

and/or patching a new and much shorter length of cable or conductor, and/or application of a joint or sleeve."[377]

1056. From this, we identified three factors as summarising SAPN's definition of minor repairs opex, namely that it would involve:

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.[378]

1057. 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).

United Energy's definition of minor repairs leaves room for interpretation

1058. The only relevant clause that we observe in United Energy'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).'*[379]

1059. 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.

1060. If a 'repair' resulting from an *asset* failure was that the asset was replaced, then this would be a replacement capital expenditure, not opex. If the repair resulted from a *component* failure that may (if not repaired) lead to the 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, this is not how United Energy has defined what it proposes as minor repairs in its Cost Allocation Methodology.

1061. The part of United Energy'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.

1062. We consider that United Energy 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 United Energy proposes classifying as minor repairs

United Energy's supporting expenditure information

1063. United Energy 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.

377 EMCa review of aspects of SAPN's 2020-25 RP (September 2019) page 58

378 Ibid, page 62

379 ATT 124 Cost Allocation Methodology, page 11

Figure 9.1: 2019 minor repairs opex, as presented by United Energy at onsite

Asset type	Type of repairs	2019 estimate, $000 2019
Pole top structures	Pole top rot repair	33
Pole top structures	Pole Top repair HV with cross-arms and insulators	6
Poles	Pole reinforcement assessment	96
Poles	Altering assets to allow pole reinforcement	5
Overground	Proactive al-cu connector repair	611
Underground	Distribution underground cable joint/terminator repair(XLPE)	1,581
Underground	Distribution underground cable joint/terminator repair(non-XLPE)	1,105
Underground	LV underground cable joint/terminator repair	646
Transformer (ZSS)	ZSS fence and lighting upgrade	194
Switchgear (ZSS)	ZSS lighting works	–
Service lines	Installation of extra height raiser bracket at customers POA and/or pole end	299
Service lines	Installation of house-end raiser bracket including new customer mains cable	139
Service lines	Install disconnect device	201
SCADA	Firmware critical upgrades - protection and control equipment inflight	14
SCADA	Firmware critical upgrades - protection and control equipment	–
Zone substation	Brick fence repairs at ZSS	10
Zone substation	Substation fencing	52
Zone substation	ZSS fencing inflight	32
	Fargo sleeve repair(3)	11
	Total expenditure	5,036

Source: United Energy EMCa presentation May 2020, page 48. Note that this information is in $2019 and was presented as being the basis for the proposed amount of $5.2m per year when escalated to $2021 real terms

1064. We sought further information on these works, including United Energy'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 United Energy'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.

1065. We also sought information on the nature of the work activities or tasks undertaken, together with United Energy's justification of the treatment of expenditure on those tasks as 'minor repairs opex' by reference to the definition in its Cost Allocation Methodology.

United Energy's repair volume and cost information tends to support classification of work of this nature as 'minor repairs'

1066. United Energy provided information for the five-year period from 2015 to 2019 on the unit costs and volumes of work that it considers to fit its definition of minor repairs. We compared this data with United Energy's historical recast RIN data and found that it matched to within around 2% in each year. Accordingly, we are reasonably satisfied that this individual repair cost data represents the types of repairs that United Energy is proposing to reclassify.

1067. In Table 9.2, we show the results of our analysis of United Energy's historical unit cost and volume information. It shows that United Energy averaged 2,583 such repairs annually over the five-year period. While there is some annual fluctuation, there were substantial numbers of such repairs in each year. The data also shows an average cost for such repairs of $1,768 over the period, with annual averages within a reasonable range of the period average.

1068. By way of 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.[380]

[380] EMCa analysis of SAPN CA RIN data provided from AER, 28 June 2019

Table 9.2: Analysis of works proposed by United Energy as 'minor repairs'

	2015	2016	2017	2018	2019	5-year average
Number of repairs	2,451	1,663	2,074	3,868	2,860	2,583
Total cost ($000)	4,337	3,864	4,277	5,147	5,211	4,567
Average unit cost ($)	**1,769**	**2,324**	**2,062**	**1,331**	**1,822**	**1,768**

Source: EMCa analysis from response to UE IR031, question 20

1069. Of the types of repairs that United Energy presents for consideration, the most costly type of repairs are what United Energy describes as replacements of *'small sections of cable'*[381] when it is determined as having faulted and caused an outage. United Energy's data shows an average unit cost for such repairs for non-XLPE cables of around $13,000 though the equivalents for XLPE and LV cable average around $8,500 and $5,000 respectively.

1070. The data also shows what appear to be three significant historical fencing repair costs, of $65,000, $201,000 and $263,000 respectively.[382] It seems unlikely that such work would meet a definition for being considered as a minor repair.

1071. Other than these, nearly all of the historical work that United Energy has presented as being indicative of what it proposes to consider as minor repairs is comprised of repair types with annual average unit costs between a few hundred dollars and a few thousand dollars. In 2019, the highest unit cost repair type (other than a fencing project referred to above) was $10,901.[383]

1072. While we consider that a qualitative definition is most appropriate for minor repairs, the individual repair cost information that United Energy provided largely appears to support classification of work of this nature as comprising 'minor' repairs.

Except for service line compliance rectification and zone substation fencings, United Energy provided descriptions of the repairs that appear consistent with the relatively low unit costs and high volumes

1073. As part of IR 031, we sought explanation for the specific types of repair categories that United Energy proposes to treat as minor repairs. In its response (to question 18), United Energy listed 17 types of repair which match the same 17 types of repair for which it provided unit cost and volume information, as above.

1074. The justification that United Energy puts forward for its treatment of the 17 types of repair as minor repairs opex, repeats the following phrase for each:

> *"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."*[384]

1075. 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 United Energy's Cost Allocation Methodology which, as we have described above, also contains only a high-level definition that is limited by its own circularity.

381 United Energy response to UE IR031, question 18 (rows 8 to 10)

382 $2021 terms

383 Ibid

384 Powercor response to IR PAL035, Question 27

1076. From United Energy's descriptions of the 'scope' of these repairs, there are four types of proposed work that appear to involve installing new assets, as follows:

- For service lines work, there are three types of work that are variously described as installing new brackets, new customer cable and/or new disconnect devices. While these may rectify a non-compliant clearance issue, we consider that, as new fittings, it is more likely that these should remain capitalised;
- We have already identified the fencing repairs above. For one of these repairs (substation fencing), United Energy describes the work as involving repairs to '*small sections*' of fencing; however, it is only in 2018 and 2019 that United Energy shows any historical expenditure for this work;
- For conductor connector works, United Energy describes this as *'replacing* (faulty connectors) *with a new standard preferred connector types'* (sic);[385] and
- United Energy similarly describes replacing conductor sleeves with '*new standard preferred sleeve types.'*[386]

1077. The remainder of described works seem to fit a reasonable definition of a minor repair. When we consider these descriptions in conjunction with the low average unit costs and high volumes, we consider it reasonable to accept them as minor repairs opex, rather than capital additions.

9.2.4 Assessment of the proposed amount

United Energy's historical information suggests a steady state repair cost that is lower than United Energy has proposed

1078. The historical expenditure information that United Energy provided is summarised in Table 9.3. There are some differences at the line item level from the amounts shown in United Energy's information (replicated in Figure 9.1) and also slight differences compared with the product of unit cost and volume information (as presented in Table 9.2). The total of $5.3m for 2019 also does not precisely match the $5.2m in $2021 real terms that United Energy has proposed, though that is a small difference. However, the five-year average is somewhat lower than either of these figures, at $4.6m.

Table 9.3: Historical recast minor repairs expenditure - $m, real 2021

Repair category	2015	2016	2017	2018	2019	5-year average
Pole top maintenance	0.1	0.0	0.0	0.1	0.1	0.1
Pole inspection and treatment	0.0	0.0	0.0	0.1	0.1	0.0
Conductor connector works	0.0	0.0	0.0	0.0	0.1	0.0
Underground cable maintenance	2.8	3.1	3.3	3.7	4.1	3.4
Service line clearance rectification	1.1	0.7	0.6	0.9	0.6	0.8
SCADA[387]	0.0	0.0	0.0	0.0	0.0	0.0
Fencing repairs	0.3	0.0	0.2	0.2	0.3	0.2
Fargo sleeve repair	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	**4.3**	**3.9**	**4.2**	**5.0**	**5.3**	**4.6**

Source: EMCa analysis from UE response to IR031, Question 20

1079. After excluding those types of work that we consider not to meet the definition of minor repairs, either through the descriptions provided or the unit cost amounts (or both) we

385 Response to IR031, Question 18 (row 7)

386 Ibid (row 19)

387 United Energy includes this line item, but with zero historical expenditure

consider the following information to be relevant in establishing a reasonable steady state allowance for minor repairs opex, as shown in Table 9.4:

Table 9.4: Historical and average minor repairs, excluding service line compliance rectification and o/h asset inspection - $m, real 2021

Repair category	2015	2016	2017	2018	2019	5-year average
Pole top maintenance	0.1	0.0	0.0	0.1	0.1	0.1
Pole inspection and treatment	0.0	0.0	0.0	0.1	0.1	0.0
Underground cable maintenance	2.8	3.1	3.3	3.7	4.1	3.4
TOTAL	**2.9**	**3.1**	**3.4**	**3.9**	**4.2**	**3.5**

Source: EMCa analysis from United Energy response to UE IR031, question 20

1080. Based on consideration of averages and of our findings on service lines compliance rectification, we consider that the amount of $5.2m per year proposed by United Energy is not reasonable. The information above also suggests that 2019 is not a representative year. We consider that, if an adjustment is made, then a reasonable basis would be to estimate steady state repair costs from the last 5 years of cost information.

9.3 Findings and implications

1081. Whilst we are concerned that United Energy's Cost Allocation Methodology does not provide a suitable and auditable definition of what it proposes to reclassify as minor repairs opex, we nevertheless consider that United Energy has provided a reasonable description of the nature of such work, supported by historical information that demonstrates that it is low-cost/high volume. Provided that United Energy was to enhance its definition of minor repairs in its Cost Allocation Methodology to more clearly include only repairs involving 'small sections' of assets and to exclude installations of 'new' assets, then we consider that it would be reasonable to allow a reclassification of such work to minor repairs opex.

1082. We consider that: (i) service line compliance rectification work that involves installing new assets; (ii) fencing repairs that do not meet the definition of repairing 'small sections' of fencing; and (iii) installing new conductor connectors and new conductor sleeves should not be classified as opex and should be excluded from historical expenditure amounts used to estimate future requirements.

1083. We observe that there are not significant variations in the expenditures annually - or at an individual category level. However, the information that United Energy has presented for 2019 represents a high point. Accordingly, we consider that the five-year average of $3.5m per year would be a reasonable basis for setting an opex allowance.

APPENDIX A – CONTEXT FOR PROPOSED INCREASE IN POLES REPEX

In this Appendix A we provide background information pertaining to a power pole failure incident that occurred in Powercor's network and which led to an investigation and technical report by ESV into sustainable wood pole management practices.

The outcome of this technical report has been cited by Powercor, CitiPower and United Energy in their respective Regulatory Proposals for the 2021-26 period.

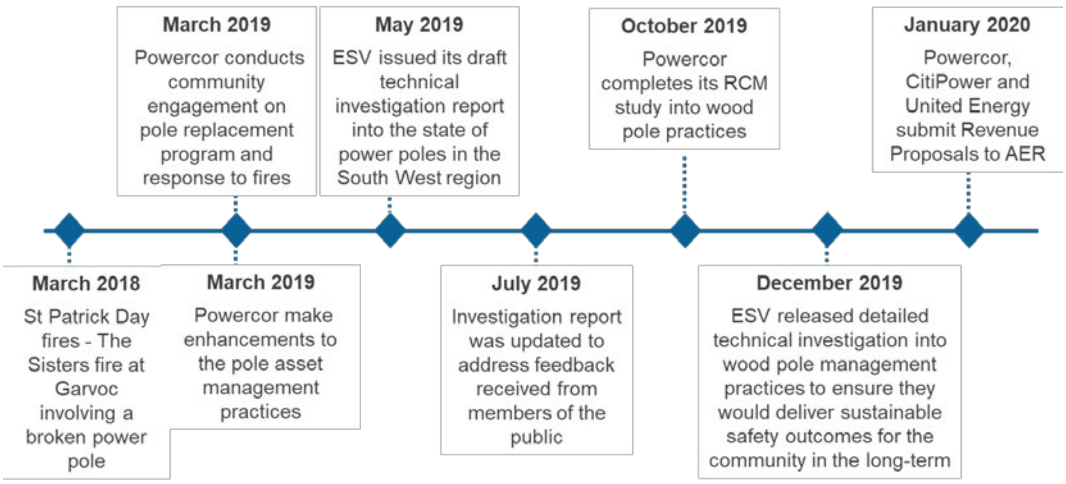
A.1 Overview

1084. 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.

1085. 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.[388] 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.

1086. 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

1087. 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.

[388] Powercor ATT245 ESV, Powercor, Sustainable wood pole safety management approach, Detailed technical report, December 2019; CitiPower do 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