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AusNet Services Distribution Revised Regulatory Proposal
2026-31

REVIEW OF SELECTED AUGEX PROJECTS

Public Version

Report prepared for:

AUSTRALIAN ENERGY REGULATOR

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Preface

This report has been prepared to assist the Australian Energy Regulator (AER) with its determination of a capex allowance for AusNet Distribution Services (AusNet) for the next regulatory period 2026-31. 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. This report relies on information provided to EMCa by AusNet. EMCa disclaims liability for any errors or omissions, for the validity of information provided to EMCa by other parties, for the use of any information in this report by any party other than the AER and for the use of this report for any purpose other than the intended purpose. In particular, this report is not intended to be used to support business cases or business investment decisions nor is this report intended to be read as a legal interpretation of the NER or other legal instruments.

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

Except where specifically noted, this report was prepared based on information provided by AER staff prior to 27 February 2026 and any information provided subsequent to this time may not have been taken into account. Some numbers in this report may differ from those shown in AusNet's revised regulatory submission or other documents due to rounding.

Enquiries about this report should be directed to:

Gavin Forrest
Managing Director, Kaihen Consulting
contact@kaihen.com.au

Prepared by
Gavin Forrest and Mark de Laeter, with input from Paul Sell

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Energy Market Consulting associates
ABN 75 102 418 020

Sydney Office
L17, 1 Denison Street, North Sydney NSW 2060
PO Box 592, North Sydney NSW 2059
contact@emca.com.au
www.emca.com.au

Kaihen Consulting
ABN 41 167 092 873

Perth Office
L28, 140 St Georges Terrace, Perth WA 6000
www.kaihen.com.au

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

ABBREVIATIONS

Term	Definition
AER	Australian Energy Regulator
AIS	Asset In Service
Augex	Augmentation Capex
AusNet	AusNet Distribution Services
BDL	Bairnsdale
BDSS	Bairnsdale Switching Station
BESS	Battery Energy Storage System
BPS	Bairnsdale Power Station
BVE	Beveridge
CDP	Construction Delivery Partners
CER	Consumer Energy Resource
CLN	Clyde North
CRE	Cranbourne
DM	Demand Management
DNSP	Distribution Network Service Provider
DOMSA	Distribution Operations and Maintenance Services Agreement
DPAR	Draft Project Assessment Report
DRN	Doreen
DSO	Distribution System Operator
DSS	Distribution Substation
DTP	Department of Transport and Planning
EAR	Energy at Risk
EPG	Epping
EUE	Expected Unserved Energy
FAS	Fall Arrest Systems
FOLCB	Fused Overhead Line Connection Box
FPAR	Final Project Assessment Report
HBRA	High Bushfire Risk Area
IDSP	Infrastructure and Development Staging Pan
IR	Information Requests
IRU	Ignition Reduction Unit
KLO	Kalkallo ZSS

Term	Definition
KMS	Kilmore South
LDC	Load Duration Curve
LDL	Lilydale
LGA	Leongatha
LLG	Lang Lang
MFA	Maffra
MTTR	Mean Time to Repair
MWTS	Morwell Terminal Station
NEO	National Electricity Objective
NER	National Electricity Rules
next RCP	2026-31 Regulatory Control Period
NPV	Net Present Value
NSP	Network Service Provider
OFR	Officer
OMSA	Operations and Maintenance Services Agreement
OSR	Options Screening Report
PCR	Project Change Control
PHI	Phillip Island
PHM	Pakenham
PSP	Precinct Structure Plan
PV	Photovoltaic; (depending on context, may refer to Present Valu)
PVR	Present Value Ratios
REFCLs	Rapid Earth Fault Current Limiters
RCP	Regulatory Control Period
RP	Regulatory Proposal
RRP	Revised Regulatory Proposal
SLE	Sale ZSS
TOMSA	Transmission Operations and Maintenance Agreement
VCR	Value of Customer Reliability
VPA	Victorian Planning Authority
VRR	Voltage Regulating Relay
WGI	Wonthaggi
WGL	Warragul
WLT	Wollert
WOTS	Wodonga Terminal Station

Term	Definition
WWF	Wonthaggi Wind Farm
ZSS	Zone Substation

EXECUTIVE SUMMARY

Introduction and context

1. The AER has engaged EMCa (in association with Kaihen Consulting) to undertake a technical review of aspects of AusNet Distribution's (AusNet) Revised Regulatory Proposal (RRP) for the 2026-2031 Regulatory Control Period (next RCP).
2. Our scope of work is directed to proposed augmentation capex (augex) which, at $881.8 [1]million in total, is over 400% more than AER's draft decision but $30.4 million less than AusNet's initial Regulatory Proposal (RP). We have been asked to review projects and programs totalling $776.5 million (88%) of the proposed augex, in three sub-categories:
   - demand-driven augex,
   - safety augex, and
   - compliance augex.
3. The assessment contained in this report is intended to assist the AER in its own analysis of the proposed capex and opex allowances as an input to its final decision on AusNet's revenue requirements for the next RCP.

Expenditure under assessment

Proposed demand-driven augmentation

4. In its RRP, AusNet's revised demand-driven augex forecast is $609.4 million for the next RCP. This is 52% above the demand-driven augex included by AusNet in its RP and over five times the AER's draft decision amount of $114.6 million.
5. In its draft decision, the AER adopted a lower demand forecast than submitted by AusNet and assessed the prudency of the proposed projects in this context. In its response, AusNet maintains that the AER's alternative demand forecast is lower than required to meet the capex objectives - specifically to manage the risk associated with expected strong demand growth.
6. We have been asked by the AER to review all the proposed demand-driven augex programs, which includes:
   - Demand-driven augex (other than LV augex) – comprising six discrete projects and two programs (Southeastern and Northern Growth Corridors) to address overloaded feeders, substations and sub-transmission loops at a total cost of $489.3 million, and
   - Demand-driven LV augex (electrification and flexible services) - comprising $120.1 million for undertaking a combination of proactive and reactive network augmentations to address anticipated thermal capacity limitations of distribution substations and LV SWER networks.

Proposed compliance and safety augex

7. In its RRP, AusNet's revised compliance and safety augex is $179.1 million for the next RCP. This is 22% above the compliance and safety augex included by AusNet in its RP and almost double the AER's draft decision amount of $91.0 million.
8. We have been asked by the AER to review four compliance projects totalling $150.8 million and two safety projects totalling $16.3 million. Our review therefore constitutes 93% of the revised proposed compliance and safety augex. We split our assessment into three parts:

[1] This figure differs slightly from that shown in AusNet's RIN. We provide a reconciliation in Table 2.3

- REFCL[2] compliance augex, comprising one program and two projects to maintain compliance: REFCL driven augmentation ($107.3 million), REFCL Bairnsdale ($21.3 million) and REFCL Lilydale ($19.3 million)
- Voltage regulator relay replacement on existing transformers with compatible modern equivalents at a cost of $2.9 million
- Safety augex – $8.3 million for completion of its program to install fall arrest systems (FAS) on its steel lattice towers, and $8.0 million for replacement of selected Fused Overhead Line Connection Boxes (FOLCB) to mitigate fire start risk.

Assessment and Findings

New information on governance, management and forecasting methods

9. We considered new information provided by AusNet in its RRP in relation to the methodologies it had applied in forecasting its augex requirements to identify whether this supports or otherwise alters our findings from our initial review of the projects and programs we have been asked to assess.

10. We focussed on the aspects in our initial review for which we had concerns and where AusNet has changed its method or approach for the RRP. Of relevance to this report, from our review of the governance, management and forecasting methods that AusNet applied in its RP, we found examples of the following issues:

- AusNet's RP lacked quality information
- Instances where the modelling methods that were applied by AusNet were flawed
- The economic analysis relied heavily on the input assumptions that AusNet has applied, but which are not always supported
- AusNet applied risk allowances which were not adequately supported.

11. We summarise our findings from the information in the RRP as follows.

The information provided by AusNet was sufficient for our review

12. In general, we found that the information provided in the RRP and supplemented by on-site discussions and responses to formal information requests was adequate to support our review process. AusNet has updated parts of its submission, and we have taken account of this updated information in our assessment of the individual projects.

Demand forecast has been updated, and increased since the RP

13. AusNet's revised forecast has had the effect of bringing into the next RCP new projects and often advancing the economic timing of demand-driven projects relative to its RP.

14. We have not been asked to review the demand forecast itself, and for the purpose of our review accept the demand forecast where relied upon in the economic modelling as proposed by AusNet. Nonetheless, we note how sensitive projects are to the demand forecast in our assessments (for possible consideration by the AER).

AusNet's economic modelling approach has been largely retained

15. With the exception of AusNet's approach to forecasting the LV augex for the next RCP, it has largely retained the economic modelling approach from its RP in which we identify several issues.

16. AusNet has now applied the 2024 Value of Customer Reliability (VCR). However, we consider there is an error in the way it determines the annuitised cost. AusNet has introduced a factor to account for underlying demand supplied by photovoltaic (PV) installations and which we consider is a coarse form of adjustment. Accordingly, for each

[2] Rapid Earth Fault Current Limiter

relevant project/program we tested the impact of the 'PV factor' on the option selection and economic timing.

We identified evidence where the assumed capex was overestimated relative to an efficient level of capex

17. For the most part, we consider that AusNet's forecasting methods for identifying projects is reasonable. AusNet, similar to other Network Service Providers (NSP), has experienced large input cost increases and the full extent of these cost increases were not reflected in the cost estimates included at the time of the RP.

18. However, we find evidence that the assumptions that AusNet has relied upon in developing its cost estimates for its RRP have led to an overestimation of its required capex. Specifically, we find that:

- AusNet has duplicated provisions for uncertainty and risk
- Application of contractor incentives has not been adequately justified

We identified evidence where costs are understated and the assumed benefits were overstated in economic analysis for some projects

19. In some instances, we found that AusNet has incorrectly derived the annualised cost of its preferred option from the discounted capex rather than the undiscounted cost leading to an understatement of the annualised cost, and the potential to affect the determination of economic timing.

20. We also found assumed benefit issues specific to the economic modelling for AusNet's LV augex projects, which are related to its counterfactual (or 'business as usual' scenario). This casts doubt on the validity of its benefits assessment for the proactive remediation work that AusNet has proposed.

Implications for forecast capex

21. We find that:

- The cost estimates are higher than an efficient level with the inclusion of allowances that we consider are collectively not adequately justified as being reasonable and efficient – we take this into account in our proposed adjustments, and
- Some aspects of AusNet's analysis may result in an overstatement of the benefits that it has assumed in its analysis of claimed project justification and economic timing, and which we review for each project.

Proposed demand-driven augex (other than LV augex)

AusNet has justified the summer and winter network readiness program

22. AusNet proposes an updated $7.0 million capex over the next RCP to address expected thermal overload of network assets. Whilst only one option is considered and the economic analysis is simplistic and applies inconsistent and unsupported input assumptions, AusNet has based its expenditure forecast on a reasonable extrapolation of historical costs, largely bypassing our concerns.

For the WGL feeder and switchboard project, a lower cost solution is available

23. AusNet's preferred network augmentation solution is one of four alternatives to the 'do nothing more' counterfactual. We consider that with reductions to AusNet's assumed costs for another of AusNet's options based on battery energy storage systems (BESS), the highest Net Present Value (NPV) would be achieved from this option. This option also provides 'option value' given uncertainty about long term demand growth.

For the balance of the projects, we consider that the solutions are prudent, however the revised costs are higher than an efficient level.

24. For each of the remaining four discrete projects and for the projects within the Southeastern Growth Corridor (eight projects) and Northern Growth Corridor (seven projects), we consider

that AusNet has reasonably responded to the concerns we expressed in our initial review and the AER's draft decision.

The proposed cost is overestimated due to the systemic issues we identified

25. The systemic issues with AusNet's cost estimation and forecasting methodology that we identified as part of our governance review lead us to our view that costs are overstated for the majority of projects.

26. This leads us to conclude that whilst adjustments are required to the costs to respond to the systemic issues we found, each of the projects is, with the assumed demand forecasts, prudent to include in the next RCP. This is primarily because of the strong demand forecast to which the economic timing of the projects is sensitive.

Projects are sensitive to the assumed demand growth

27. Given the sensitivity of demand-driven projects to the assumed demand growth, AusNet's economic models include sensitivity analyses for various factors including demand. For the low case scenario, which is relevant to most projects (and which is based on 90% of AusNet's assumed base case forecast), the economic timing of several projects would be deferred until after the final year of the next RCP.

LV augex

AusNet has not justified undertaking a proactive upgrade program

28. AusNet has sought to justify, through economic modelling, undertaking a proactive program to upgrade LV distribution substations (DSS). In its modelling it has adopted a counterfactual for the purposes of estimating future expected unserved energy by assuming that:

- any demand probabilistically above 127.2% of each distribution substation's (DSS) continuous rating (i.e. an overload threshold) is unsupplied energy; and
- conversely, any load that is less than this thermal overload limit is assumed to be supplied.

29. This counterfactual does not reflect operational practice or reality; therefore, its claimed economic modelling does not provide a valid measure of the benefits of such a program and therefore does not provide justification for the proactive programs that it proposes.

AusNet has justified a need for some increase in LV augex

30. AusNet has provided adequate justification of the need for increased LV augex, and which it may choose to apply reactively or proactively to DSS and to SWER as required.

Safety augex

Fall arrest system capex is prudent

31. The AER included AusNet's proposed fall arrest system capex in its draft decision, however AusNet has sought to increase the cost after including delivery partner support costs. This has no effect on our assessment of the scope and direct cost. Consequently, we consider that the scope and direct cost are respectively prudent and reasonable to be undertaken in the next RCP.

Fused Overhead Line Connection Boxes (FOLCB) program is prudent

32. AusNet has provided evidence that its fire start performance is declining with a link to a significant rise in Ignition Reduction Units (IRU) failures on FOLCBs including in high-risk bushfire areas. We are satisfied that this has significantly increased the risk of continued use of FOLCBs with this failure mode in these areas.'

33. We consider that the proposed safety augex of $8.0 million for the Codified FOLCB replacement project is prudent and reasonable to be undertaken in the next RCP.

Compliance augex

REFCL compliance

34. AusNet has reduced its REFCL-driven augmentation program scope for the five remote REFCL units by removing the isolation transformers included in the RP estimate. However, AusNet has significantly increased the unit cost, and we do not consider that AusNet has adequately demonstrated that its assumed cost is at an efficient level.

35. AusNet has included two REFCL projects (at Bairnsdale and Lilydale) due to delays in securing land in the current RCP. We consider that the scope for the two projects is reasonable and that the cost forecast to be required in the next RCP is reasonable with the exception of the combination of allowances that it has not adequately justified.

Voltage regulator relay

36. The Voltage Regulator Relay Replacement project was not included in AusNet's RP and AusNet had expected instead that it would be completed in the current RCP. However, a delay due to a safety matter has reasonably led to some capex that is forecast to be incurred in the first year of the next RCP.

37. With the exception of the over-estimated cost allowances, we consider the project cost to be reasonable.

Implications for expenditure allowances

Our approach

38. We were asked to consider an alternate expenditure forecast for the projects and programs that we reviewed based on the issues that we identified. Where a project was reasonably justified in accordance with the National Electricity Rules (NER), we include this in our alternative expenditure forecast. In other cases, our proposed alternative expenditure forecast for the categories of expenditure we were asked to review involves one or more adjustments, to the extent to which we consider AusNet's forecast to be not justified and/or to be overstated.

39. Our alternative forecasts necessarily apply only to the aggregate of the projects within the scope of our review. Our assessment of an alternative expenditure forecast is intended to assist the AER in its own analysis of the proposed expenditures allowance as an input to its final determination on revenue requirements for the next RCP.

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

Alternative forecast for reviewed projects

AusNet's proposed forecast for the augex-driven projects (not including LV augex) is higher than a prudent and efficient level

41. The net result of applying the adjustments described above is an alternative forecast of $421.0 million, which compares with AusNet's initial proposal of $489.3 million.

AusNet's proposed forecast for LV augex and flexible services is higher than a prudent and efficient level

42. The net result of applying the adjustments described above would result in an alternative forecast central estimate of $26.4 million for LV augex, which is $93.7m (78%) less than AusNet's revised proposal of $120.1 million. This compares with AusNet's initial proposal of $138.5 million, noting that the AER disallowed this entirely in its draft decision

AusNet's proposed safety augex is prudent and represents an efficient level

43. We consider the proposed capex of $16.3 million proposed by AusNet is reasonable

AusNet's REFCL compliance augex is higher than a prudent and efficient level

44. The net result of applying the adjustments described above is to propose an alternative forecast of $122.0 million, which compares with AusNet's initial proposal of $147.9 million.

AusNet's voltage regulator relay compliance augex is higher than an efficient level

45. The net result of applying the adjustments described above is to propose an alternative forecast of $1.9 million, which compares with AusNet's initial proposal of $2.9 million.

Aggregate adjustment

46. As requested by the AER, we have developed a central estimate of alternative forecasts consistent with our findings, based on the new information that AusNet has provided in its models and its responses to our information requests.

47. We propose adjustments for the issues that we have identified, and which lead us to a central estimate of the required capex for the selected augex projects that we have been asked to review as approximately 24% lower than the $776.6m that AusNet has proposed for the projects we were asked to review.

48. We suggest that this is more accurately represented as a range of between 20% to 30% lower than AusNet has proposed, or between $543.6 million and $621.3 million for the next RCP.

1 INTRODUCTION

The Australian Energy Regulator (AER) has engaged EMCa (in association with Kaihen Consulting) to review and provide advice on aspects of AusNet Distribution's (AusNet) proposed expenditure over the 2026-31 Regulatory Control Period (next RCP) included in its Revised Regulatory Proposal (RRP). Our review is based on information that AusNet provided and on aspects of the National Electricity Rules (NER) relevant to assessment of expenditure allowances.

We have reviewed each of the 28 projects that we were asked to review, included in AusNet's forecast augmentation capex (augex). We have taken account of information provided in its RRP including associated reports and workings that AusNet has provided, together with AusNet's responses to information requests and discussions held at an onsite review meeting with AusNet representatives on 22 and 29 February 2026. As at the time of completing this report, we have shared the substance of our findings with AER.

1.1 Purpose of this report

49. The purpose of this report is to provide the AER with a technical review of selected project expenditure that AusNet has proposed in its RRP for the next RCP.

50. The assessment contained in this report is intended to assist the AER in its own analysis of the proposed expenditure allowance as an input to its Final Determination on AusNet's revenue requirements for the next RCP.

1.2 Scope of requested work

51. The AER's definition of the scope of the required work is reproduced in Figure 1.1.

Figure 1.1: AER's definition of the scope of required work

Scope of work covered by this report

The key aspect for EMCa to assist is reviewing a number of the augmentation and replacement revised proposals from AusNet Distribution.

AusNet Demand driven, compliance and safety augmentation projects:

Demand Driven augmentation

1. *FY27-31 Summer / Winter Network Readiness Program - LV Network Capacity (overloads)*
2. *Augment Eastern Cranbourne 66kV Loop*
3. *Augment East Gippsland 66kV Loop*
4. *New Wollert ZSS*
5. *New Pakenham South ZSS*
6. *WGI new Tx*
7. *Install a new 22kV distribution feeder (WOTS21)*

8. Install a new 22kV distribution feeder (WGL31)

9. LV Augex (Electrification & Flexible Services)

10. Pakenham South ZSS 22kV Feeder Augmentation (3 Feeders - PHS11, PHS12 & PHS13)

11. Wollert ZSS 22kV Feeder Augmentation (3 Feeders - WLT12, WLT13 & WLT14)

12. Install a new 22kV distribution feeder (CLN33) (Delayed Project)

13. CLN 3rd Transformer and Switch room (WIP)

14. Pakenham South ZSS 22kV Feeder Augmentation (1 Feeder - PHS21)

15. Wollert ZSS 22kV Feeder Augmentation (1 Feeder - WLT21)

16. Install a new 22kV distribution feeder (CRE34)

17. Install a new 22kV distribution feeder (CLN32)

18. CBTS 66kV Feeder Rearrangement

19. Beveridge Zone Substation Development Project

20. Beveridge ZSS 22kV Feeder Augmentation (2 Feeders - BVE11 & BVE12)

21. Beveridge ZSS 22kV Feeder Augmentation (3 Feeders - BVE13, BVE14 & BVE21)

22. Augment SMTS-BVE-KMS 66kV Line

Compliance

1. Voltage Regulator Relay Replacement (WIP)•

REFCL Compliance

1. REFCL Bairnsdale (BDL) augmentation (Delayed Project)

2. REFCL Lilydale (LDL) augmentation (WIP)

3. REFCL Driven Augmentation

Safety

1. Fall arrest systems

2. Codified FOLCB replacements

1.3 Our review approach

1.3.1 Approach overview

52. In undertaking our review, we:

- Completed a desktop review of the information provided to us by the AER
- Assisted the AER in preparing requests for information to AusNet, and reviewed the information provided by AusNet (via the AER)
- Undertook a virtual onsite meeting with AusNet on 22 February 2026 focussed on the LV augex forecasting methodology, and a further virtual onsite meeting on 29 February 2026 focussed on the proposed expenditure. On both occasions AusNet presented to our team on the scoped topics, and we had the opportunity to engage with AusNet to consolidate our understanding of its proposal.

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

54. We have subjected the findings presented in this report to our peer review and quality assurance processes and we presented summaries of our findings to the AER prior to finalising this report.

1.3.2 Conformance with NER requirements

55. In undertaking our review, we have been cognisant of the relevant aspects of the NER under which the AER is required to make its determination and relevant AER guidelines.[3]

1.3.3 Technical review

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

57. We have sought to assess AusNet's expenditure proposal based on AusNet's analysis and AusNet's own assessment of technical requirements and economics and the analysis that it has provided to support its proposal. Our findings are therefore based on this supporting information and, while we have sought to test AusNet's modelling and assumptions, our review does not encompass developing separate entirely bespoke modelling or assumptions.

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

1.4 This report

1.4.1 Report content

59. We have included four further sections of this report:

- In Section 2, we provide a summary of the capex proposed in AusNet's RRP, with a focus on the changes to its augex forecast.
- In Section 3, we provide our assessment of the new information that AusNet has included in its RRP on application of its forecasting methodologies to the projects and programs we have been asked to review.
- In Section 4, we provide our consideration of the new information that AusNet has included in its RRP to support the forecast augex for the projects and programs we have been asked to review.

1.4.2 Information sources

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

[3] Including the AER's industry practice application note Asset Replacement Planning (2024).

61. Except where specifically noted, this report was prepared based on information provided by AER staff prior to 27 February 2026 and any information provided subsequent to this time may not have been taken into account.

62. Unless otherwise stated, documents that we reference in this report are AusNet documents comprising its RRP and including the various appendices and annexures to that proposal.

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

1.4.3 Presentation of expenditure amounts

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

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

2 EXPENDITURE SUMMARY OF AUSNET'S RRP

Our review is of specific projects totalling $776.6 million within AusNet's revised proposal for $881.8m of augmentation capex. AusNet's RRP augex proposal is $29.4 less than AusNet proposed in its initial RP, but over four times greater than the amount that AER allowed in its draft decision.

Despite the total augex included in the RRP being slightly lower at a total level than AusNet had included in the RP, the composition of the augex program has changed with large increases to some projects and programs.

We have been asked to review a selection of the proposed augex program included by AusNet in its RRP and we present the findings of our assessment in Section 4, and a proposed alternative forecast in Section 5.

2.1 Introduction

66. In this section, we provide an overview of AusNet's capex forecast for the next RCP, and we contrast this with an analysis of the corresponding expenditure in the current RCP for the elements of the expenditure forecast under review.

67. We provide a breakdown of the proposed capex for the categories of expenditure we have been asked to review and point out some of the drivers for change that we explore in subsequent sections of this report.

2.2 Overview of proposed total capex

68. AusNet has forecast total capex for the next RCP of $3,864.5 million (gross capex) as shown in Table 2.1. This represents a relatively small uplift from the RP, however an increase of 93% above the AER's draft decision.

Table 2.1: Comparison of gross capex forecast for next RCP ($m, real June 2026)

AER category	RP	AER draft decision	RRP
Replacement	1,316.9	681.0	1,218.8
DER capex	89.5	32.5	92.1
Augmentation	911.2	219.0	881.8
Connections	576.5	503	793.3
ICT capex	386.7	245.2	349.8
Property capex	173.7	119.7	145.7
Fleet capex	144.2	87.5	173.5
Other non-network capex	4.6	4.5	4.5
Capitalised overheads	209.1	111.1	204.9
Gross capex	**3,812.4**	**2,003.6**	**3,864.5**

Source: AusNet RRP. Table 5-1[4]

2.3 Comparison of AusNet's augex proposals

2.3.1 What AusNet has proposed

69. Our review is primarily focussed on augmentation capex, which at $881.8 million based on Table 2.1 is slightly lower than the $911.2 million that AusNet proposed in its RP but four times the amount that AER allowed in its draft decision.

70. As shown in Table 2.2, the composition of the proposed augex forecast included in the RRP has changed relative to the RP, despite the proposed expenditure being slightly lower than the RP.

Table 2.2: Comparison of augex forecast for RP, AER draft decision and RRP ($m, real June 2026)

	RP	AER draft decision	RRP
Demand-driven (excluding LV augex)	261.9	114.6	489.3
Demand-driven (LV augex only)	138.5	0	120.1
Connection enablement	180.4	0	0
Compliance and safety	146.4	91.0	179.1
Reliability	137.4	0	39.7
Resilience	42.6	20.4	22.8
Other[5]	4.1	2.9	30.8
Total	**911.3**	**228.9**[6]	**881.8**

Source: EMCa derived from ASD – AusNet Distribution – SCS Capex Model – 011225 – CONF and the AER draft decision. There may be small differences due to rounding.

4 In AusNet's RRP, Table 5-1 is denoted as being expressed in $m, real $2024 however the RRP values are the same as AusNet's SCS capex model expressed in $m, real $2026. AusNet's values for the draft decision (in its RRP table 5-1) also vary from those in AER's draft decision (at table 2.4, page 9), including for each category.

5 The other category included in this table comprises innovation and insurance augex. For the RRP, this also comprises non-network capex and repex to reconcile with the augex total.

6 This amount is the same as in AER draft decision, however we note that it varies from the AER draft decision value that AusNet quotes in its table 5-1.

71. We have been asked to review a selection of augex projects totalling $776.6 million as presented in Section 4 of this report, along with the findings of our assessment.

2.3.2 Reconciliation of RIN and AER categorisation of augex

72. Using the RIN categories, AusNet has stated that its augex forecast is $914.3 million for the next RCP. We have reviewed the source of the differences, and present these in Table 2.3, which relate to:[7]

- removal of DER related augex from the RIN categories; and
- addition of two projects to the RIN categories to reconcile with the AER category augex.

73. As shown in Table 2.3, the additional projects are for land purchases and repex. In accordance with our scope of review, we have included review of the proposed repex projects in our review of safety-related augex.

Table 2.3: Reconciliation of RIN and AER categorisation of augex ($m, June 2026)

	FY27	FY28	FY29	FY30	FY31	RCP total
Augex (RIN categories)	215.4	210.3	227.7	141.8	119.1	**914.3**
REMOVE: DER related augex						**-**
Supply improvement	*(4.5)*	*(4.6)*	*(4.6)*	*(4.7)*	*(4.7)*	***(23.1)***
CER Enablement	*(12.1)*	*(3.5)*	*(8.8)*	*(1.8)*	*(9.8)*	***(36.1)***
ADD: other capex projects						**-**
Strategic land purchases (non-network)	*1.7*	*6.8*	*0.1*	*-*	*10.0*	***18.7***
Codified FOLCB replacements (repex)	*1.6*	*1.6*	*1.6*	*1.6*	*1.6*	***8.0***
Augex (AER categories)	**202.0**	**210.7**	**216.0**	**137.0**	**116.2**	**881.8**

Source: EMCa derived from ASD – AusNet Distribution – SCS Capex Model – 011225 - CONF

2.4 Summary

74. AusNet has forecast total capex for the next RCP of $3,864.5 million (gross capex). This represents a relatively small uplift from the RP, however an increase of 93% above the AER's draft decision.

75. Our review is of specific projects totalling $776.6 million within AusNet's revised proposal for $881.8m of augmentation capex. AusNet's RRP augex proposal is $29.4 less than AusNet proposed in its initial RP, but over four times greater than the amount that AER allowed in its draft decision. The composition of the proposed augex forecast included in the RRP has changed relative to the RP, and we consider a number of those changes in Section 4.

[7] As determined from AusNet's SCS Capex model using the categories nominated at columns AQ:AX of the Input | Projects worksheet. DER capex is a separate category to augmentation.

3 ASSESSMENT OF NEW INFORMATION ON APPLIED METHODOLOGY

We consider that AusNet's forecasting methods for identifying projects was reasonable, however we found evidence that the assumptions that AusNet has relied upon in developing its cost estimates has led to an overestimate of its required capex.

We found that some aspects of AusNet's analysis may result in an overstatement of the benefits that it has assumed in its analysis of economic timing, and which we review for each project in Section 4. This includes application of a scaling factor to its calculation of Unserved Energy, referred to as the PV factor. For the purposes of our assessment, we focussed on whether the application of this factor was likely to advance the timing of projects relative to if the factor had not been applied, through sensitivity analysis of AusNet's modelling.

3.1 Introduction

76. In this section, we consider the new information provided by AusNet in its RRP in relation to the methodologies it had applied in forecasting its augex requirements, and whether this leads us to alter the findings set out in our initial review for the project we have been asked to review.

77. Specifically, we have focussed on those matters where we found issues in our initial review and where AusNet has changed its method or approach for the RRP.

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

3.2 Assessment of matters relating to updating of governance arrangements and forecasting methods

3.2.1 AusNet's response to the draft decision

AusNet has responded to the AER draft decision in its RRP, which resulted in an uplift of proposed capex for the areas we have been asked to review

79. We have reproduced AusNet's summary of the AER key concerns and AusNet's response included in the RRP for the primary categories of capex we have been asked to review in Table 3.1.

Table 3.1: Summary of AusNet's response to the AER's draft decision on capex (selected categories only)

AusNet capex category	AER's key concerns in its draft decision	AusNet's response to the draft decision
Demand-driven augex (excluding LV augex)	• Hardcoded values in economic models • Project timing susceptive to relatively small changes in demand • Lower cost option rejected without sufficient justification • Lack of other typical network alternatives in options analysis • Insufficient consideration of transfer capacity between feeders • Insufficient consideration of demand management • Unit power factor (pf) assumption too conservative • Require evidence-based cost justification	• Comprehensively redeveloped our demand-driven augmentation expenditure forecasts • Developed a Northern Growth Corridor plan that clearly explains the constrains in the area and why our proposed package of works addresses the constraints • Similarly, developed a South-Eastern Growth Corridor plan • Refreshed business cases that account for the revised demand forecast, and interactions between assets • Single business case and economic model for the Northern Growth Corridor so that interactions between assets are clear • Soft coded models • Tested NPV results at +/- 10% of demand forecast • Adopted more appropriate pf factors • Expanded options analysis
Demand-driven augex (LV augex only)	• Lacks adequate justification • Insufficient analysis of potential overlaps • Overestimated economic benefits • Inconsistencies between cost benefit analysis assumptions and recorded data • Value of unserved energy is not justified	• Reviewed our approach to calculating unserved energy and have applied a more robust method • Addressed overlaps • Provided further justification to support our proposed unit rates
Compliance including REFCL	• Unexplained cost item for REFCL	• Updated cost for REFCL with detailed cost build-up

Source: AusNet – EDPR Revised Proposal 2027-31, Table 5-2

80. In addition to AusNet's response in Table 3.1, we have reviewed AusNet's response to concerns regarding the inclusion of risk allowances in its cost estimates and approach for using VCR.

AusNet states several drivers for the proposed increase in the number and scope of projects in the next RCP

81. In its RRP, AusNet states that the key drivers of change to the RRP relative to the RP are:

- further increases to the demand forecast arising from the combination of a hot 2024/25 summer and development announcements; and
- further cost uplifts from greater scope maturity, inflationary pressures since the cost estimates had been prepared for the RP.

82. The combination of these factors has led to an increase in forecast capex for the next RCP for the projects we have been asked to review. As shown in Section 2, whilst at a total

augex level the forecast capex proposed for the next RCP is similar, the composition of projects is quite different.

83. We observe that the compounding effect of increased scope (and cost) and increased demand (and supply risk) has contributed to the increase in proposed expenditure for the next RCP.

84. In the assessment we include in Section 4, we consider the scope changes and cost increases that AusNet has proposed, and how these have been modelled by AusNet alongside changes in the forecast demand to determine the economic timing relative to what was proposed in the RP.

AusNet has introduced new projects that were not present at the time of the RP

85. In its draft decision, the AER was not satisfied that AusNet's total capex forecast reasonably reflects the capex criteria, (in particular, we are *'not satisfied that it reasonable reflects the prudent and efficient costs, and a realistic expectation of demand and cost inputs required, to meet the capex objectives).'*[8]

86. The AER outlined an alternate estimate of capex and encouraged AusNet to '*respond to the issues we have raised in our draft decision and welcome further supporting information in its revised regulatory proposal.*'[9]

87. As AusNet's RRP includes materially new information that we had not previously assessed, we have undertaken a bottom-up assessment of the projects that we have been asked to review.

3.2.2 Demand forecast

Demand forecast has been updated, and increased since the RP

88. A large part of the identified benefit for its proposed demand-driven augex is the rescued supply risk, which is a factor of the demand forecast assumed by AusNet. AusNet states that it has updated the '*peak demand forecasts to address the AER expectations as set out in the draft decision*.'[10]

89. AusNet states that the main changes made to the demand forecasts include:[11]

- Incorporating the latest data, reflecting the higher summer and winter peaks over the last 12 months
- Inclusion of commercial and industrial electrification, including the impact of electrification on the C&I sector
- Adjustment for block loads and other drivers, updating the treatment of block load assumptions, which, for example, has contributed to the increase in the first-year forecast for both maximum and minimum demand in growth corridors
- Balanced approach to demand drivers, accounting for downward adjustments for energy efficiency and battery uptake, and upward adjustments for electrification and block loads.

90. We have not been asked to review the demand forecast, and for the purpose of our review accept the demand forecast where relied upon in the economic modelling as proposed by AusNet.

91. In the event that the forecast demand is not realised, and therefore is lower than AusNet has forecast, then the supply risk would similarly be reduced. We would expect that in most cases this reduction would result in deferral of the economic timing relative to the economic timing that has been identified by AusNet. In our assessment, we consider those projects

8 Attachment 2 – Capital expenditure | Draft decision – AusNet Services distribution determination 2026-31. AER. Page 3.

9 Attachment 2 – Capital expenditure | Draft decision – AusNet Services distribution determination 2026-31. AER. Page 3.

10 AusNet – EDPR Revised Proposal 2027-31. Page 61.

11 AusNet – EDPR Revised Proposal 2027-31. Page 10.

that are sensitive to changes in demand assumptions. However, this does not always imply project deferral as the nature of the demand-driven augex that AusNet has proposed, relates to growth in new developments and therefore the supply risk is biased to the connection to new load, rather than the risk of interruptions to existing loads. We also observe that for some projects, AusNet states that the network is already experiencing network overloads.

3.2.3 Economic assumptions and assessment

Economic modelling approach has largely been retained

92. For the bulk of the projects that we have been asked to review, the economic modelling adopted for the RP has been retained, and 'in general' represents a reasonable approach. For the LV augex project, AusNet has substantially relied on similar economic analysis to that which it utilised for its RP, and which we describe the issues that we have identified in Section 4.4.3.

AusNet has updated its value of VCR to align with the latest information

93. In the draft decision, the AER did not accept AusNet's hybrid approach to VCR and required AusNet to apply the 2024 AER VCR, in its RRP, which reflects the reliability preferences of the relevant mix of customers affected by each option considered.[12]

94. For its demand-driven augex, after assessing the impact of applying the AER's 2024 VCR values in place of AusNet's hybrid approach to VCR, the AER concluded that[13] '*while it did reduce the NPV results materially, the results remain positive for demand driven augmentation expenditure.*'

95. AusNet has updated the value of VCR that it has applied to its demand-driven projects that we have been asked to review, and weighted the VCR based on the customer composition for the project. We consider that this is a reasonable approach.

Annuitised cost has been incorrectly derived in the economic modelling

96. We found evidence where AusNet has incorrectly derived the annualised cost of its preferred option from the discounted capex rather than the undiscounted cost leading to an understatement of the annualised cost. Whilst ordinarily, this may result in potential deferral of the economic timing, we found that in general, the timing is not impacted due to the scale of benefits associated with the demand growth.

An additional factor is applied by AusNet to account for underlying demand supplied by PV

97. We also observed that AusNet had applied a factor to some demand forecasts to account for the impact of PV, that is the underlying gross demand before impact of PV. Specifically, should the PV be unable to provide supply (e.g. due to an outage at the transmission or distribution level), the amount of demand affected is not only the net demand that was being supplied from the network but also the demand that was being supplied by the PV.

98. AusNet states that a factor had been previously applied to adjust the net demand to reflect the gross demand (i.e. including that supplied by the PV). AusNet has developed summer and winter PV factors that effectively scale the energy at-risk, by a value of up to 1.33 and 1.13 respectively.[14] Based on our review of aspects of the AusNet transmission proposal, we observe application of the PV factor to their projects also.

99. We accept that PV contributes to meeting customer load, and in the absence of PV (such as when the PV is disconnected because of a network outage) the demand (and energy) on

12 Attachment 2 – Capital expenditure | Draft decision – AusNet Services distribution determination 2026-31. AER. Page 23.

13 Attachment 2 – Capital expenditure | Draft decision – AusNet Services distribution determination 2026-31. AER. Page 36-37.

14 We also saw evidence where the PV factor was set to 1.0 for some projects, and as a result had no effect on the expected unserved energy calculation.

the network that is unsupplied will be higher than the net demand (and energy) that were being provided by the network. We consider that the calculation method developed by AusNet is fairly coarse and may not take sufficient account of diversity or timing of the sources of energy in the calculation of energy at-risk, such that the PV factor as applied by AusNet may result in overstating the unserved energy. For the purposes of our assessment, we therefore considered how sensitive the outcome of AusNet's analysis was to the addition of this factor.

100. We also asked AusNet to assess the impact of setting the PV factor to 1.0, thereby removing the effect of this scaling factor in its modelling. In its response to IR069, AusNet states that this change to the PV factor does not materially affect the timing:[15]

> *'A sensitivity analysis has been undertaken, which demonstrates that even when the PV Factor is set to 1, effectively removing its influence on Expected Unserved Energy (EUE), all demand-driven projects remain economically justified within the same EDPR period. The PV Factor has limited materiality on optimal project timing because it is applied only to the weighted EUE rather than to the underlying demand forecast. As a result, its influence is diluted, given that a substantial level of EUE already exists for all proposed projects.*
>
> *Across all sensitivity scenarios, the PV Factor does not materially affect the optimal timing of investment, with all projects continuing to fall within the same regulatory control period.'*

Capex smoothing has been applied

101. AusNet has deferred some augex projects beyond the economic timing from its economic modelling, based on prioritisation of projects, as shown in Table 3.2.

Table 3.2: Example of some project deferrals / capex smoothing – Northern Growth Corridor projects

Substation	Economic timing	Year of commissioning (based on the SCS capex model)	EMCa analysis of SCS capex model (final year of capex)
Beveridge ZSS	FY28	Cost of station & 2 feeders spread across FY27 and FY28 with an expected Asset In Service (AIS) date of FY28 (matching the optimal year)	Beveridge ZSS, FY28 Initial 2 feeders, FY28 Subsequent 3 feeders, FY30 Sub-transmission, FY30
Wollert ZSS	FY28	Cost of station & 3 feeders spread across FY27 to FY29 with an expected AIS date of FY29 (deferred one year beyond optimal year).	Wollert ZSS, FY29 Initial 3 feeders, FY28 Subsequent 1 feeder, FY30
Pakenham South ZSS	FY28	Cost of station & 3 feeders spread across FY27 to FY29 with an expected AIS date of FY29 (deferred one year beyond optimal year).	Pakenham ZSS, FY29
Eastern Cranbourne 66kV loop upgrade	FY28	Cost spread across FY27 to FY30 with an expected AIS date of FY30 (deferred two years beyond optimal year)	Eastern Cranbourne 66kV loop upgrade, FY30

Source: EMCa derived from RRP, Table 5-7 and SCS capex model

[15] AusNet response to IR069.

3.2.4 Cost estimation and accuracy

AusNet, similar to other NSPs, has experienced large input cost increases and that the full extent of these cost increases were not reflected in the cost estimates included at the time of the RP

102. AusNet states that the increase in cost included in its RRP is driven by:[16]

- The addition of new feeders and associated civil and electrical works for new zone substations
- Updated supplier pricing for materials, equipment, and labour
- Project-specific constructability requirements identified through more detailed planning.

103. In support of the updated costs, AusNet has provided detailed cost estimates, an explanation of the drivers of cost increases in response to our requests for information, and an independent review by Worley for a sample of its major projects.

104. From the findings of the independent review, AusNet conclude that the revised estimates are consistent with the NER and AER guidance:[17]

> *'Worley has found that while our revised estimates are higher than those in the January 2025 Proposal, these changes are supported by current market evidence, recent tender outcomes, and benchmarking against industry standards. In some cases they reflect more mature design and delivery assumptions.*
>
> *The report also highlights that the revised estimates remain consistent with the National Electricity Rules (NER) and the AER's Expenditure Forecast Assessment Guideline.'*

105. We reviewed the Worley report, which concludes that:[18]

> *'Across the reviewed projects, the updated estimates reflect current market unit costs and demonstrate appropriate application of AusNet's CEM [Cost estimation Methodology].'*

106. According to Worley, the higher cost estimates included in the RRP, relative to those included in the RP (as at January 2025) are due to:[19]

- The cost of labour and materials has risen sharply and become more volatile since the original estimates were prepared, with labour rates increasing by around 25-35 percent.
- The January estimates were based on older unit rates and benchmarks that do not reflect the strong escalation seen from 2023 to 2025.
- Project scopes for zone substations (ZSS) and feeders have been refined and expanded as planning and design matured. This includes changes such as addition of feeders, clearer station equipment requirements, improved civil and building quantities, and more realistic construction staging inputs.

107. These reasons were similarly presented by AusNet in our discussions.

108. The increases presented by AusNet and Worley are directionally consistent with our own experience, and information relied upon by AEMO, including its 2025 Electricity Network Options Report, including:[20]

> *'An important result of this update [2025 Transmission Cost Database] was that project cost estimates produced using the updated Transmission Cost Database were, dependent on scope, approximately 25% to 55% higher (in real terms) for overhead lines*

16 AusNet – EDPR Revised Proposal 2027-31. Page 10.

17 AusNet – EDPR Revised Proposal 2027-31. Page 10.

18 Review of AusNet Major Project Pricing, Revised Proposal – 2026 to 2031 Determination. Worley Consulting. Page 2.

19 Review of AusNet Major Project Pricing, Revised Proposal – 2026 to 2031 Determination. Worley Consulting. Page 8.

20 2025 Electricity Network Options Report. AEMO. Page 32.

than those in the 2023 update, and approximately 10% to 35% higher (in real terms) for substation projects.'

109. Based on the information presented by AusNet, we accept that the cost estimates that AusNet had relied upon for its RP did not reflect current market rates and once updated would result in an increase in cost estimate relative to the RP.

We accept that some of the cost increases are due to genuine scope changes and improvement to scope maturity

110. In several of the project we have reviewed, we found evidence of changes to planning and design assumptions associated with substation layout, feeder configurations and topology, and construction and deliverability assumptions. These changes resulted in updates to the scope, and in some cases triggered a review of an expanded set of options relative to the RP. We consider the merits of specific scope changes in our assessment of each of the proposed projects in Section 4.

111. We accept that the combination of updating for more recent market data, and increased scope maturity has resulted in an increase to the expected cost of projects. We therefore considered whether the method for determining expected cost for the purposes of establishing a regulated capex allowance was reasonable, specifically the combination of cost allowances in the base cost estimate and risk allowance.

Application of project risk allowance must be specific, and reasonably likely to arise

112. Worley describes the quantitative risk assessment process applied by AusNet as including two parts:[21]

- Inherent risks capture the uncertainty in the defined scope, including variation in quantities, unit rates, and constructability assumptions - the "known unknowns" in delivering the project.
- Contingent risks are events that may or may not occur during delivery and include delays in access, industrial action, community constraints, or changes in key assumptions - the "unknown unknowns", with have an identifiable basis, in delivering the project.

113. Worley describe the application of probability distributions to each of the risk types '*derived through expert judgement and historical performance.*'[22] On the basis that the analysis determines a P50 value, AusNet conclude that this aligns with the expected-value cost of the identified risks, and include this in the cost estimate, where the:[23]

'Direct cost plus a P(50) risk allowance produces an unbiased, probability weighted cost estimate with an equal likelihood of actual costs exceeding or coming in below the estimates.'

114. AusNet states that a P50 risk allowance has been included for:

- Individual and discrete projects delivered by major project delivery partners - with cost estimated using internal estimate
- Bulk programs to be delivered by Zinfra - with cost estimated using contracted rates
- Bulk programs to be delivered by major project delivery partners – with cost estimated using internal estimate.

115. We consider the application to discrete projects only, in accordance with the scope of our review. In its draft decision, the AER states its position as:[24]

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21 Review of AusNet Major Project Pricing, Revised Proposal – 2026 to 2031 Determination. Worley Consulting. Page 22.

22 ASD – Worley – Appendix 5D AusNet Services Regulatory Cost review – 1DEC2025 CONF. Page 23

23 AusNet – EDPR Revised Proposal 2027-31. Page 53.

24 Attachment 2 – Capital expenditure | Draft decision – AusNet Services distribution determination 2026-31. AER. Page 24.

'As a general principle, we only accept risk allowances in limited circumstances that are specific to a particular project or program.'

116. The AER did not accept the general contingency risk allowance that AusNet had proposed, and states that:[25]

'AusNet should provide adequate justification and evidence for any proposed risk allowance, demonstrating that it relates to a specific, identifiable risk associated with a particular project, consistent with the principles outlined in this section.'

117. In principle, and consistent with the AER draft decision, we consider that the inclusion of project risk allowances for project specific risks is reasonable, if the risk allowance is determined on a reasonable basis, reflects project specific costs that are reasonably like to arise, and that those costs have not been accounted for in other parts of the expected cost.

AusNet has duplicated provisions for uncertainty and risk

118. In its RRP, AusNet states that the included risk allowance covers risk-costs not captured in direct cost estimates for individual programs and projects.

119. We have reviewed the additional information provided by AusNet in response to our information request IR069 and requested additional clarity on the development of cost estimates included in the RRP, specifically the inclusion of additional allowances for items such as planning levies, investigations and studies, and also inclement weather. We sought to understand how the relationship between the inclusion of these allowances and the risks included in the P50 probabilistic risk allowance are determined.

120. In its response, AusNet states that 'The estimating approach is to include highly probable (say >75% likelihood) costs as a direct cost, and to include items with a lower probability in the risk allowance.'[26]

121. We infer from AusNet's full response, that as a part of developing the direct cost, the expected cost on P50 basis, represents the value at which there is a 50% chance that the estimate will be higher than required, and a 50% chance that it will be lower. Therefore, there is a distribution around the expected value. The approach taken by AusNet to include 'highly probable' costs and including a risk allowance, is likely to result in a cost estimate that is upwardly biased.

122. We understand that many of the cost estimates relied upon by AusNet have been developed as a bottom-up assessment of the expected cost. For substation projects, AusNet states that it does not have recent experience with constructing substations to draw upon.

123. The risk allowance includes provision of inherent risks and contingent risks.

124. We asked AusNet for evidence of how it had identified and quantified the risk costs, including a copy of the risk model (or spreadsheet) that has been used to determine the risk allowance. We reviewed the risk models that AusNet provided,[27] and found that the risk allowance is made up of:

- An inherent risk allowance is determined by assuming an asymmetric three-point distribution around the direct cost estimate and applying a Monte Carlo analysis.
- A contingent risk allowance is determined based on likelihood of a range of risks occurring (delay, scope creep, weather, market conditions, etc.) and applied to a three-point estimate of consequence. The three-point consequence is asymmetric in nature, and subject to a Monte-Carlo analysis to determine the P50 value.

125. We do not consider that this value is reasonable, project specific, and not otherwise accounted for in the expected value.

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25 Attachment 2 – Capital expenditure | Draft decision – AusNet Services distribution determination 2026-31. AER. Page 25.

26 AusNet response to information request IR069.

27 AusNet response to IR079.

126. In considering the contingent risk, it is important to first determine whether the direct cost makes no other allowance for uncertainty within each of the nominated components. If that is true, then there is a case for adding a risk allowance, to the extent that the uncertainty results in additional cost, based on the methods adopted by AusNet. However, based on the evidence provided by AusNet in support of its cost estimate, we consider that uncertainty has been included in both the direct cost estimate and P50 risk allowance, such that there is likely to be a level of duplication. An example of this is the inclusion of weather days, whereby an allowance of 10 days delay is included in the direct cost, and a further delay beyond 10 days included in the risk allowance. This ignores the possibility that the project experiences a level of weather delay much less than 10 days, by positively skewing the cost estimate.

127. Whilst variations between cost estimates are expected to reflect the specific scope of the work, and allowances are a reasonable approach for items where design information is not available, the issues that we have identified with such allowances indicate a bias towards over-estimation relative to the efficient cost of the projects.

Application of contractor incentives has not been adequately justified

128. [redacted]

129. In response to our information request IR079, AusNet states that *'[t]hese provisions encourage our partners to deliver projects safely within the specified timeframes and thereby ensuring efficient outcomes and delivering value to customers.'*

130. Whilst consideration of contractual incentives that act to promote innovation and efficiency improvements or offset cost increases are consistent with AER guidance and good practice, AusNet has not demonstrated how its proposed contractor incentives achieve this.

131. AusNet also states that [redacted][28]

132. Based on our review, we saw examples where the incentive rates were higher than AusNet has advised for the CDPs.

133. We did not see sufficient linkage to value for consumers, or evidence to demonstrate how the inclusion of the incentive rates is aligned with the National Electricity Objective (NEO) and NER. We conclude that AusNet has not demonstrated that inclusion of contractor incentives in the assumed cost of projects is reflective of the efficient cost of the projects.

Some costs have not been adequately justified

134. AusNet has provided detailed cost breakdowns for some projects and which identify such allowances and adjustments as project management, 'mark-ups/'adjustments'. We consider that that these costs have not been adequately justified, leading to an overstatement of the total cost. For example, for construction delivery partners (CDP):

- AusNet has typically assumed CDP [redacted] which in our experience are on the high side, [redacted] allowances are provided for AusNet itself as well
- AusNet has assumed CDP adjustments (also referred to as mark-ups) of [redacted] which is not adequately justified given other provisions in the estimates for risk.

28 AusNet response to IR079.

Inclusion of contractor support costs

135. AusNet's proposed capex forecast includes allocation of contractor support costs as described in its RRP.[29] This comprises:

- [redacted]
- [redacted]

[redacted]

3.3 Summary and implications for the aspects of expenditure we have been asked to review

3.3.1 Summary

Information provided by AusNet was sufficient for our review

141. In general, we find that the information provided was adequate to support our review process. AusNet has updated parts of its submission, and we have taken account of this updated information in our assessment of the individual projects in Section 4.

Demand forecast has been updated, and increased since the RP

142. AusNet has made changes which result in an increase to its demand forecast. As a large part of the identified benefit for its proposed demand-driven augex is the rescued supply risk, and a factor of the demand forecast assumed by AusNet, this results in advancement of the timing for some projects.

143. We have not been asked to review the demand forecast, and for the purpose of our review accept the demand forecast where relied upon in the economic modelling as proposed by AusNet.

[29] ASD - AusNet - EDPR Revised Proposal 2027-31 -Dec2025_CONF(31101959.1). Page 64.

144. In the event that the forecast demand is not realised, and therefore is lower than AusNet has forecast, then the supply risk would similarly be reduced. We consider how sensitive projects are to the demand forecast assumptions in our review in Section 4.

We identified evidence where the assumed capex was overestimated relative to an efficient level of capex

145. For the most part, we consider that AusNet's forecasting methods for identifying projects was reasonable, however we found evidence that the assumptions that AusNet has relied upon in developing its cost estimates has led to an overestimate of its required capex.

We identified evidence where the assumed benefits were overstated for some projects

146. AusNet has applied a scaling factor to its calculation of Unserved Energy, referred to as the PV factor. For the purposes of our assessment, we focussed on whether the application of this factor was likely to advance the timing of projects relative to if the factor had not been applied, through sensitivity analysis of AusNet's modelling.

147. Related to this, we find that AusNet has incorrectly derived the annualised cost of its preferred option from the discounted capex rather than the undiscounted cost leading to an understatement of the annualised cost, and the potential to affect the determination of economic timing.

3.3.2 Implications for forecast capex

148. Of the issues that we have identified:

- We find that the cost estimates are higher than an efficient level with the inclusion of allowances that we consider are collectively not adequately justified as being reasonable and efficient
- Some aspects of AusNet's analysis may result in an overstatement of the benefits that it has assumed in its analysis of economic timing, and which we review for each project in Section 4.

149. In subsequent sections of this report, we have reviewed evidence of the application of AusNet's governance arrangements and forecasting methods, and whether any of the issues impact the expenditure forecast proposed for individual projects.

4 ASSESSMENT OF NEW INFORMATION FOR PROPOSED EXPENDITURE

We reviewed the information provided by AusNet to support its proposed augex program included with its RRP. Our focus is to assess the extent to which the forecast expenditure is likely to meet the NER criteria, including whether there is evidence of the issues identified in Section 3 that affect the reasonableness of AusNet's forecast. We also consider the extent to which AusNet has addressed issues raised in the AER's draft decision, and in light of the additional information included in the RRP, we undertook a bottom-up review of each of the proposed projects.

We find that AusNet has reasonably justified the need for undertaking most of the projects identified for the next RCP. However, we continue to have concerns with the modelling approach of the proposed LV augex project, and which was identified in the AER's draft decision. We consider that for the LV Augex Program, AusNet has not demonstrated that it is beneficial to move from its current approach of considering upgrades following faults, to adopting a proactive approach based on its modelling. We consider that a level of expenditure to manage an increase in forecast overloads is reasonable, but this would be less than AusNet has proposed.

Whilst we have tested the sensitivity of AusNet's proposed projects to the demand forecast, it is beyond our scope to review the demand forecast itself. If demand does not eventuate as AusNet has assumed, this may lead to re-prioritisation of some of the proposed projects and delayed timing of the identified need.

As we have discussed in Section 3, we identified instances where AusNet's estimate of cost is likely to lead to an overestimate relative to the efficient project cost.

4.1 Introduction

150. In this section, we consider the new information provided by AusNet in its RRP in relation to the selected projects we have been asked to review.

4.2 What AusNet has proposed

151. AusNet has proposed $881.8 million augex the next RCP. We have been asked to review targeted projects and programs totalling 88% of the proposed augex, or $776.5 million for the next RCP.

152. For the purposes of our assessment, we have based the proposed augex on AusNet's categorisation using the AER categories as shown in Table 4.1. Within 'demand-driven augex' we have separated the LV augex and flexible services project to align with how we have presented our assessment in the subsequent sections.

Table 4.1: Proposed augex ($m, June 2026)

DNSP category	FY27	FY28	FY29	FY30	FY31	RCP total
Demand-Driven Augex (other than LV augex and flexible services)	136.6	141.8	119.5	64.6	26.9	**489.3**
Demand-Driven Augex (LV augex and flexible services only)	30.6	29.0	16.2	29.8	14.4	**120.1**
REFCL compliance	22.2	23.0	25.8	27.5	49.4	**147.9**
Compliance	2.9	-	-	-	-	**2.9**
Safety (augex)	1.7	1.5	1.6	1.5	2.0	**8.3**
Safety (repex)	1.6	1.6	1.6	1.6	1.6	**8.0**
Sub-total (EMCa scope of review)	**195.6**	**196.9**	**164.7**	**125.1**	**94.3**	**776.6**
Other augex categories[30]	6.4	13.8	51.3	11.9	21.9	**105.2**
Total	**202.0**	**210.7**	**216.0**	**137.0**	**116.2**	**881.8**

Source: EMCa derived from ASD – AusNet Distribution – SCS Capex Model – 011225 – CONF

4.3 Demand-driven augex (other than LV augex and flexible services)

4.3.1 Summary of RP and AER draft decision

153. In its RP, AusNet's demand-driven augex (excluding LV augex) was primarily made up of proposed developments in the northern and southeastern growth corridors: comprising the establishment of Wollert and Pakenham South substations respectively.

154. In its draft decision, the AER included $114.6 million in the capex allowance for demand-driven augex.[31] Other demand-driven projects were not included due to concerns relating to the reasonableness of the proposed demand forecast inputs, and which indicated that projects could be reasonably deferred, and projects where AusNet had not demonstrated that the proposed option was prudent:[32]

> *'For demand driven augmentation, we are concerned that AusNet's demand forecast may be overestimated. This means there are potentially more projects than necessary and some of these could be deferred to future regulatory periods. In forming our alternative estimates, we have adopted a low case demand forecast and assessed the prudency of the proposed projects. We require AusNet to update its demand forecast using the latest information, such as AEMO's July 2025 Inputs, Assumptions and Scenarios Report (IASR), and to provide additional evidence supporting the reasonableness of its demand forecasts and associated augmentation expenditure in its revised proposal.'*

155. The AER provided a table of the proposed augex, draft decision and a summary of its reasons. We provide a copy of relevant parts of this table in our assessment of the demand-driven augex projects within our scope.

30 This includes Reliability Improvement, Resilience, Insurance, and Innovation.

31 Attachment 2 – Capital expenditure | Draft decision – AusNet Services distribution determination 2026-31. AER. Table 2.5.

32 Attachment 2 – Capital expenditure | Draft decision – AusNet Services distribution determination 2026-31. AER. Page 29.

156. The AER expressed concern regarding insufficient explanation, justification and supporting evidence for its proposed augex and provided guidance on what it expected to see from AusNet in its revised proposal:[33]

> *'Our primary concern with AusNet's proposal is the absence of comprehensive analysis of all available options, as well as insufficient explanation, justification, and supporting evidence for the proposed investments and the options selected. While we acknowledge the increasing demand that may necessitate new investments, we require AusNet to provide sufficient, relevant information and documentation to enable us to properly assess the prudency and efficiency of the proposed expenditure.'*

4.3.2 What AusNet has proposed

157. AusNet has proposed $609.4 million for demand-driven augex for the next RCP as shown in Table 4.2.[34] This is a 52% increase on its RP of $400.4 million, and over five times the AER draft decision of $114.6 million.

Table 4.2: Demand-driven augex projects ($m, June 2026)

Project	FY27	FY28	FY29	FY30	FY31	RCP Total
FY27-31 Summer / Winter Network Readiness Program - LV Network Capacity (overloads)	1.4	1.4	1.4	1.4	1.4	**7.0**
Augment Eastern Cranbourne 66kV Loop (CBTS-OFR Line)	1.2	2.5	7.3	16.8	-	**27.8**
Augment East Gippsland 66kV Loop (MWTS-TGN-MFA lines)	10.1	11.6	14.0	4.5	-	**40.2**
Install a new 20/33 MVA Transformer at WGI Zone Substation	-	-	-	5.5	6.6	**12.1**
Install a new 22kV distribution feeder (WOTS21)	-	-	0.6	5.9	-	**6.4**
Install a new 22kV distribution feeder (WGL31) & New Switchboard at WGL ZSS	2.6	7.1	23.1	-	-	**32.8**
LV Augex (Electrification & Flexible Services)	30.6	29.0	16.2	29.8	14.4	**120.1**
Southeastern growth corridor	35.2	33.8	28.2	3.2	18.8	**119.3**
Northern Growth Corridor	86.1	85.4	44.9	27.3	-	**243.7**
Total	**167.2**	**170.8**	**135.7**	**94.4**	**41.3**	**609.4**

Source: EMCa derived from ASD – AusNet Distribution – SCS Capex Model – 011225 - CONF

158. In its response, AusNet considers that the AER's alternative demand forecast is lower than is required to meet the capex objectives, specifically to meet and manage a realistic expectation of demand on its network:[35]

> *'We consider the AER's alternative forecast is insufficient to manage increasing network risk associated with strong customer and demand growth expected on our network and maintain reliable supply to our growing customer base.'*

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33 Attachment 2 – Capital expenditure | Draft decision – AusNet Services distribution determination 2026-31. AER. Page 38.

34 Note that this amount includes LV augex which is assessed in section 4.4

35 ASD - AusNet - EDPR Revised Proposal 2027-31 -Dec2025_PUBLIC. Page 111.

159. AusNet has updated its demand-driven augex forecast based on revision to its demand forecasts, developed network development plans and strengthened its analysis and business cases.

160. AusNet's RRP, focuses on two growth corridor programs, being the Northern and Southeastern growth corridors and which extend the analysis that it had included in its RP. AusNet has also re-submitted many of the other demand-driven projects in its RRP, based on updated analysis. We have taken this new information into account in our assessment.

161. We provide our assessment of AusNet's proposed LV augex program in Section 4.4.

4.3.3 Assessment of Summer and Winter Network Readiness Program

Overview of RP program and AER's draft decision

162. AusNet's proposed summer and winter readiness program is based on pro-active investment each year to '*prepare AusNet's electricity distribution HV network for the expected peak demand during the summer period from November to March and winter period from May to August.*'[36] Specifically, AusNet seeks to address sites where emerging load growth creates a risk of network constraints. AusNet notes that the exact location of these issues cannot be identified until closer to each summer and winter peak period.

163. Table 4.3 summarises the proposed expenditure in AusNet's RP and the AER's draft decision showing both the quantum of reduced expenditure and the rationale for doing so. The key issue identified by the AER was that the cost breakdown of the proposed expenditure did not reveal a methodology commensurate with high productivity and efficiency.[37]

Table 4.3: AusNet RP and AER draft decision – Summer and Winter Network Readiness Program ($m, FY26)

Project	AusNet Proposal	AER draft decision	AER reasons
FY27-31 Summer and Winter Network Readiness Program	6.0	3.0	We conclude that the need for this program is reasonable. However, we are not satisfied that the proposed unit rates reflect efficient expenditure. We have applied our alternative unit cost based on historical cost.

Source: AER draft decision, Attachment 2 – Capital expenditure, Table A.2

Overview of RRP program

164. AusNet has provided a business case to support the RRP for the next RCP, in which AusNet states that it has increased its forecast expenditure to $7.0 million:[38]

- due to cost pressures; and
- after refining the scope of work.

Our assessment

The program responds to expected thermal overload of network assets

165. A 'summer/winter readiness' program is a common feature of Distribution Network Service Providers' (DNSP) demand-driven expenditure programs. The scope of work is usually set for completion before the onset of the next summer and winter period, associated with the peak demand conditions on the network. Overloaded assets are forecast by comparing

36 AusNet – FY27-31 Summer Winter Readiness program – 0112205 – CONF. Page 2.

37 AER draft decision, Attachment 2. Page 36.

38 AusNet - FY27-31 Summer Winter Readiness program – 0112205 – CONF. Page 2.

asset capacity against demand projections derived from the most recently available actual localised peak demand.

166. We are satisfied that with the increases in demand that AusNet predicts to occur over the duration of the next RCP, it is likely there will be overloaded assets that can be prudently addressed proactively from application of one or more actions from a 'toolkit' of solutions.

Only one option is considered and the forecast is based on historical expenditure

167. AusNet's revised (November 2025) business case presents only a 'do nothing' counterfactual and Option 1, which is to proactively mitigate overloaded distribution transformers, LV conductor, HV/LV fuses, distribution poles and other distribution assets.

168. The total cost of the 'do nothing' option is $0.0 million in the business case and AusNet's economic model.[39]

AusNet's economic analysis is simplistic and applies inconsistent and unsupported input assumptions

169. AusNet's economic analysis is simplistic with the avoided expected unserved energy (EUE) derived from assuming two distribution feeders, ten distribution substations, and 15 LV circuits will be overloaded each year.[40] These assumptions are not supported by sufficient analysis in the business case or the model. The extent of overload and therefore the energy at risk (EAR) is similarly derived from simplistic and largely unsupported assumptions about the extent of overload and other factors.

170. The EUE is valued at $1.0 million p.a. ($2024) and continues for 30 years. This is compared by AusNet with the annualised capital cost for the preferred option of $0.3 million to conclude that the economic timing for the work is FY27[41] with an NPV of $8.5 million,[42] which is repeated in Table 4 of its business case.

171. The annualised capital cost of $0.3 million is derived from $5.8 million ($1.15 million p.a. $2024) capex assumed to be incurred over the next RCP and a 30-year study period to avoid overloads. However, the capex is actually derived from a much smaller number of 'solutions'[43] than assumed in the derivation of the EUE.[44] Applying the same number of overloaded assets used to derive the EUE for the 'do nothing' option, the total capex over five years would be $16.5 million,[45] the NPV is reduced to $0.4 million and economic timing retained as FY27.

172. It appears that AusNet has reverse-engineered the capital cost to match its assumed annual average expenditure of $1.15m (rounded to $1.2m, $2024) derived from historical expenditure, as discussed below. This leads us to question the usefulness of the model, because AusNet is basically proposing a continuation program with the forecast annual expenditure for the next RCP based on historical expenditure.

AusNet claims its unit costs are now evidence-based but uses historical expenditure for the forecast for the next RCP

173. In the revised business case included in its RRP, AusNet states that it has '*obtained detailed, evidence-based unit rates to strengthen the cost estimate methodology for the*

39 AusNet – FY27-31 Summer Winter Network Readiness Program economic model – 01122025 – CONF.

40 AusNet – FY27-31 Summer Winter Network Readiness Program economic model – 01122025 – CONF. Worksheet 2.3.6. Supply Risk calculation.

41 This economic timing aligns with the start of the next RCP, and comes as no surprise as AusNet is positioning this as an ongoing annual program.

42 AusNet – FY27-31 Summer Winter Network Readiness Program economic model – 01122025 – CONF. Worksheet 1.1. BC Summary, Visualisation of optimal commissioning year.

43 Such as replacement with higher capacity transformers.

44 See worksheet 2.3.2 Option 2 Cost in the economic model, noting that Option 2 in the economic model is Option 1 in the business case; the annual capex is based on 0.8 HV feeders, not 2; 4.6 distribution transformers, not 10, and 3.5 LV circuits, not 15.

45 Worksheet 2.3.2 Option 2 Cost in the economic model.

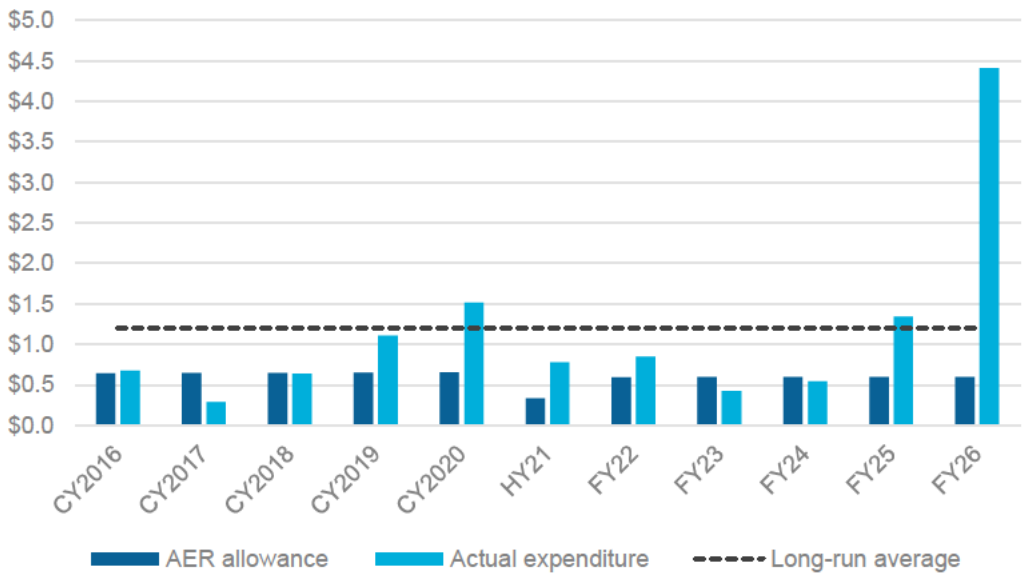
Summer/Winter Readiness Program and align with our LV Network & Flexible Services, and CER Enablement augmentation program unit rates.'[46]

174. AusNet states that it has updated its unit costs based on recent costs incurred for the four types of asset upgrades. In aggregate the revised unit rates result in a slight uplift to the RP values.[47]

175. Regardless, AusNet has '*assumed that the funding required for this program is comparable to historical expenditure.'*[48] As there was no indication in the business case of the historical spend, we asked AusNet to explain how it derived the $1.4 million p.a. ($2026) capex that it has forecast for the upcoming program.

176. AusNet's response provided the annual actual historical expenditure in $2024, which is shown in Figure 4.1 and which also shows the long-run average annual capex of $1.2 million ($2024),[49] which when escalated to $2026, is equivalent to the level of capex that AusNet has proposed at $1.4 million p.a. or $7.0 million over the five years of the next RCP.

Figure 4.1: Annual historical Summer/winter readiness capex vs AER allowance ($m, real June 2024)



Source: IR#069 – Response to EMCa questions 1-9 23012026 – CONF, page 16

177. We asked AusNet to explain the elevated capex in FY26, which from its response,[50] is driven by establishing the Kalkallo ZSS (KLO) temporary generation site which included [redacted] capital works.[51] We accept this explanation. We note that AusNet considers the capex that it proposes to be conservatively low given: [52]

> *'the increasing level of network risk in growth corridor areas which, while this will be addressed through augmentation projects (if approved by the AER), will need to be*

46 AusNet FY27-31 Summer Winter Readiness program – 0112205 – CONF. Page 5.

47 AusNet FY27-31 Summer Winter Readiness program – 0112205 – CONF. Table 6.

48 AusNet FY27-31 Summer Winter Readiness program – 0112205 – CONF. Page 5.

49 Taking account of the half-year HY21 capex.

50 AusNet Response – IR69 Follow-up questions – 27022026 – CONF.

51 Site preparation works (earthworks, footings and structures); Protection, control and SCADA upgrades; Two new ACRs One new sectionaliser; Supply, installation, testing and commissioning of five 2MVA Kiosks, including modification to LV bus; Installation of one 2m x 2m x 2.4m shed for site storage including electrical service; Additional poles.

52 AusNet Response – IR69 Follow-up questions – 27022026 – CONF.

managed prior to delivery of these augmentations. This will involve the continued deployment of generation to meet peak demand.'

178. We further note that the annual average expenditure over the last five years is somewhat higher at $1.5 million ($2024) and that excluding the outlier FY26 capex reduces the long-run average to $0.9 million ($2024), which is similar to the HY21-FY25 average. In summary, we consider the long run average of $1.2 million p.a. ($2024) to be a reasonable basis for the forecast for the next RCP, as it strikes a reasonable balance between the short term and long-run average.

Related programs

179. AusNet has also proposed an LV Augex program which we assess in Section 4.3.11. We asked AusNet to explain how the two programs relate given that they are both directed towards proactive alleviation of distribution network asset overloads. AusNet advised that the summer and winter network readiness program is targeted to alleviating thermally overloaded assets primarily in High Bushfire Risk Areas (HBRA) and Codified areas of the network (and the Electrification program is not). We are satisfied that there is unlikely to be a material overlap between the two programs.

Summary of findings

180. AusNet has undertaken an annual summer and winter readiness program for at least a decade and proposes to continue a targeted proactive program to addresses sites where emerging load growth creates a risk of distribution asset overloads in the next RCP.

181. AusNet's economic model seems to be contrived to align with the proposed average annual expenditure. Nonetheless, we are satisfied that AusNet's capex forecasting approach based on average historical expenditure provides a reasonable estimate for the next RCP.

4.3.4 Assessment of project to augment Eastern Cranbourne 66kV Loop

Overview of RP program and the AER's draft decision

182. The Eastern Cranbourne 66kV sub-transmission loop consists of seven ZSSs with an eighth, the proposed new Pakenham South (PHS) ZSS, expected to be commissioned by 2028.

183. AusNet identified increasing EAR in this network due to rapid demand growth in the Southeastern Growth Corridor, with maximum loop demand already exceeding the N-1 loop capacity and projected to exceed the N loop capacity during the next RCP.

184. AusNet proposed installing a new 66kV line between Cranbourne Terminal Station (CBTS) and Officer ZSS (OFR) by FY28.

185. Table 4.4 summarises the proposed expenditure in AusNet's RP and the AER draft decision both in terms of the quantum of reduced expenditure and the rationale for doing so. The key issue was the sensitivity of the economic timing to the demand forecast.

Table 4.4: AusNet RP and AER draft decision – Eastern Cranbourne 66kV Loop ($m, FY26)

Project	AusNet Proposal	AER draft decision	AER reasons
Augment Eastern Cranbourne 66kV Loop	38.8	0.0	We consider the project to be reasonable. However, its timing is sensitive to demand. AusNet has not provided the demand forecast model. We are unable to assess the project's timing under a lower demand scenario. Using the Augment East Gippsland 66kV Loop model as a proxy for this project, a lower demand forecast will result in the project likely to be deferred by approximately 2 to 3 years, i.e.2031 or 2032, placing it outside the regulatory period.

AER draft decision, Attachment 2 – Capital expenditure, Table A.2

Overview of RRP program

186. AusNet has revised its load forecast. The maximum loop demand has exceeded its N-1 capacity of 214 MVA and it expects maximum demand will exceed the loop's N capacity of 320 MVA by 2026 under the summer 50POE forecast. *'The network's thermal constraints are expected to escalate, with demand reaching 365 MVA in 2026 and 393 MVA in 2028 under PoE10 conditions.'*[53]

187. AusNet proposes to install a new 66kV line between CBTS and OFR with a reduced cost estimate of $27.8 million and deferred completion timing to FY30, despite the economic timing as determined by AusNet remaining as 2028. Essentially AusNet has rejected the AER's application of a lower demand scenario for this project *'…as it [the AER's assessment approach] is inconsistent with the industry's standard practice of using a 70% weighting to 50POE and 30% weighting to 10%POE.'*[54]

Our assessment

188. The options considered are unchanged from the RP, but the increased forecast demand has brought forward the economic timing.

189. AusNet considered five options to provide additional network capacity in its original business case and economic model, selecting Option 1 (new CBTS-OFR 66kV line) primarily because it had the highest NPV. The same options have been presented in the Final Project Assessment Report (FPAR) and in the economic model, with the results of the analysis shown in Table 4.5. The FPAR also reports on AusNet's assessment of the responses to the Options Selection Report (published in February 2025) and the Draft Project Assessment Report (July 2025). Option 1 still has the highest NPV according to AusNet's modelling and remains its preferred option.

Table 4.5: Summary of options analysis ($m, real June 2024)

Option	Capex	NPV
Do nothing	0.00	0.00
Option 1 (preferred): Install a new CBTS-OFR 66kV line	27.95	339.3
Option 2: Install a new CBTS-PHM 66kV line	36.69	325.4
Option 3: Install a new CBTS-PHS and new PHS-PHM 66kV line	40.86	314.9
Option 4: Install a new CBTS-LLG 66kV line	58.42	174.6
Option 5: Install a new 25 MW/100 MWh battery at OFR	58.56	57.3

Source: AusNet – FPAR Augment Eastern Cranbourne 66kV Loop CBTS-OFR line – 26112025 – PUBLIC, Table 6
CBTS Cranbourne Terminal Station; OFR Officer ZSS; PHM Pakenham ZSS; PHS Pakenham South ZSS; LLG Lang Lang ZSS

53 AusNet – FPAR Augment Eastern Cranbourne 66kV Loop CBTS-OFR line – 26112025 – PUBLIC. Page 4.

54 AusNet RRP. Page 123.

190. In its original business case and economic model, the planned commissioning of PHS in 2028 offloaded the 66kV loop, reducing the annual avoided EUE below the annualised Option 1 cost until 2031 (i.e. the economic timing was 2031). When combined with a demand growth assumption of 100% 50POE,[55] the economic timing was deferred to 2033 or 2034, using AusNet's model.

191. With the updated forecast peak demand, PHS still has an impact on EUE, as shown in Figure 4.2, however, the reduced EUE is still higher than the annualised cost of the proposed solution. When combined with the lower annualised capital cost for Option 1, the economic timing is brought forward to 2028.

192. We asked a number of questions of AusNet to explore the robustness of its modelling and options considered. The topic areas and responses are summarised as follows:[56]

- N-1 line outage probability: AusNet confirmed that approximately 97% of the total unserved energy cost is incurred under system normal operating conditions, with the balance attributed to N-1 conditions (i.e. 66kV line outages). We are satisfied that the forecast outage rates for the lines are unlikely to be a critical issue in the options analysis, including the economic analysis.
- Sizing of the BESS in Option 5: AusNet advised that it sized the BESS to maintain the CBTS 66 kV loop within its summer system-normal thermal limit during the next RCP. The energy capacity of 100 MWh (4 hours) was determined from the duration of summer peak exceedance events, derived from load-duration-curve analysis - a 4-hour BESS should be able to sustain full discharge for the critical peak window.
- Consideration of a new CBTS–BWN 66kV line as an option: AusNet advised that the option was considered and rejected because: (i) strengthening CBTS–BWN[57] will not deliver the required power injection capacity into the load growth centres; and (ii) the existing CBTS–BWN circuit is constrained by a 77MVA summer cyclic rating and would need to be uprated (i.e. in addition to the new line) to remove the constraint.
- Consideration of 66 kV feeder cut-ins at NRN, BWN or OFR (either as stand-alone options or as an initial phase of OFR works): AusNet advised that these options were considered and rejected because: (i) there is limited capacity and reduced EUE benefit; (ii) outage and constructability constraints; and (iii) the superiority of the preferred option.
- Errors in the economic model – AusNet confirmed that whilst there were errors in some cells within the model, there is no impact on the preferred option or economic timing for this option.[58]

193. We are satisfied that these responses demonstrate that: (i) the options considered in the FPAR represent the best five alternatives to doing nothing; (ii) the BESS sizing is reasonable; and (iii) that the preferred option and economic timing of the preferred option is not impacted by the spreadsheet errors.

Economic timing is sensitive to the demand forecast

194. AusNet has included a sensitivity analysis in its updated model. The economic timing is very sensitive to demand. For the low demand scenario (base case demand x 90%), the economic timing for Option 1 is deferred until 2033.[59]

195. The economic timing is not particularly sensitive to variation in VCR or capital cost.

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55 The base case demand forecast is weighted 70% 50PoE and 30% 10POE.

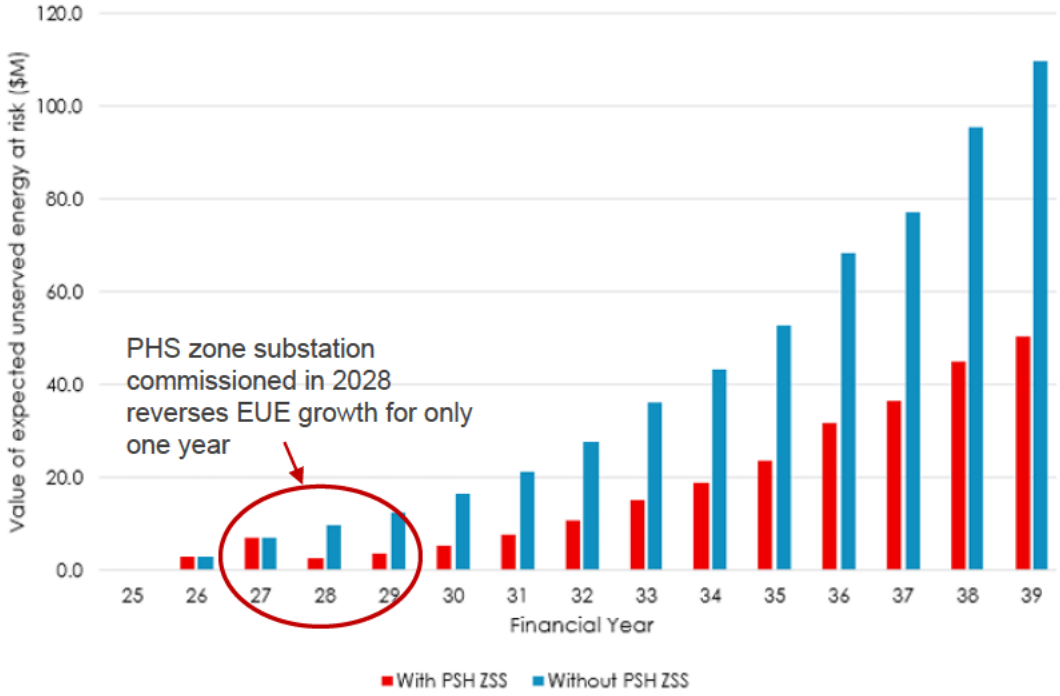
56 IR079 AusNet Response – 13022026 – CONF. Pages 13-17.

57 Berwick North ZSS.

58 However, AusNet note that there is a one year deferral to the economic timing of the East Gippsland augmentation, which we consider in our assessment of that project.

59 AusNet – Augment Eastern Cranbourne 66kV Loop economic model – 01122025 – CONF, worksheet 3.2.5 NPV (low demand) for which the annualised cost of $1.8 million is exceeded in 2033.

Figure 4.2: Value of expected energy at risk on Eastern Cranbourne 66kV network loop



Source: AusNet – FPAR Augment Eastern Cranbourne 66kV Loop CBTS-OFR line – 26112025 – PUBLIC, Figure 6

196. AusNet has incorporated PV factors of 1.33 (summer) and 1.13 (winter) in determining the value of EUE for contingency (N-1) and non-contingency (N) overload scenarios for the Eastern Cranbourne 66kV loop. As discussed in Section 3.2.3, AusNet has advised that the economic timing (2028) for its preferred option does not change even if the PV factors are set to 1.0.

Cost estimate has reduced

197. The cost estimate for the project has been reduced by a significant $11 million, which has in turn reduced the annualised cost of Option 1 and the 'hurdle' for the economic timing.

198. We asked AusNet to explain the cost reduction and we were advised that: (i) [redacted] removing overheads, finance charges and P90 risk allowances (i.e. the RP included costs that should not have been included in the capex model); and (ii) the balance is due to lower project costs.

Summary of findings

199. AusNet's proposed construction of a new CBTS–OFR 66kV sub-transmission line in the next RCP is, with the assumed demand forecast, the prudent solution. Whilst the economic timing is FY28, AusNet proposes project completion in FY30 due to deliverability management.

200. We are satisfied that the proposed capex represents a reasonable estimate at this stage of the project development lifecycle, except for the combination of allowances that it has not sufficiently justified, as discussed in Section 3.

4.3.5 Assessment of project to augment East Gippsland 66kV loop

Overview of RP program and the AER's draft decision

201. The Eastern Gippsland 66kV sub-transmission loop is the longest in AusNet's network and is geographically isolated. It includes six ZSSs.

202. AusNet identified that coincidental 50POE demand was expected to exceed N capacity by 2027 and the loop's N voltage collapse limit of 180MVA was expected to be surpassed by

the summer of FY32 (10PoE). The thermal capacity limits would require load shedding of up to 50% of the total demand under certain worse case conditions and voltage collapse was expected to result in full loss of supply across the loop.

203. AusNet proposed reconductoring the entire Traralgon to Maffra (TGN–MFA) 66kV line in 2029 to provide more loop capacity, presented as Option 1 in the RP submission. Related to this project and included as a part of separate 'Connection Enablement' projects, AusNet was planning to increase the capacity of the Morwell Terminal Station (MWTS) –TGN 66kV lines (per 'Morwell East Stage 1'), and to increase the capacity of the MWTS - Sale (SLE) and SLE–Maffra (MFA) 66kV lines (per 'Morwell East Stage 2').

204. Table 4.6 summarises the proposed expenditure in AusNet's RP and the AER's response for the Augment East Gippsland 66kV Loop project both in terms of the quantum of reduced expenditure and the rationale for doing so. The key issue was that the sensitivity of the economic timing of the project to the demand forecast.

Table 4.6: AusNet RP and AER DD – East Gippsland 66kV loop ($m, FY26)

Project	AusNet Proposal	AER draft decision	AER reasons
Augment East Gippsland 66kV Loop	30.6	0.0	We consider the project to be reasonable. However, its timing is sensitive to small variations in demand. Under a lower demand forecast, the project is likely to be deferred by approximately 3 years, i.e.2032, placing it outside the regulatory period.

AER draft decision, Attachment 2 – Capital expenditure, Table A.2

205. The AER did not include the Connection Enablement projects in the draft decision capex allowance, which means that two related upgrades of MWTS–TGN 1 and 2 (submitted as Morwell East Stage 1) will not be proceeding under these projects, as discussed further below.

Overview of RRP program

206. AusNet has identified increasing EAR in this network compared to the previous forecast, increasing supply risk.[60] In its Draft Project Assessment Report (DPAR), AusNet states that:

> *'..coincidental loading expected to exceed the loop's 144 MVA "N" capacity by 2026/27 under Probability of Exceedance (POE)50 condition and surpass the 162 MVA voltage collapse limit by 2025/2026 under POE10. Under worst-case N-1 conditions (MWTS-SLE outage), the loop's 86.3 MVA thermal limit would be exceeded under POE50.'*[61]

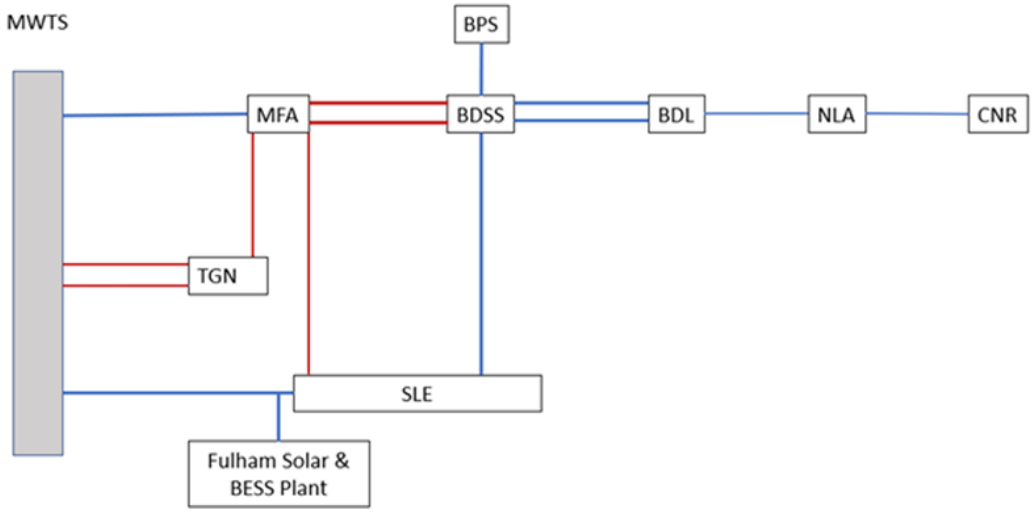
207. Referring to Figure 4.3, AusNet proposes to augment the MWTS–TGN No 1 and No 2 66kV lines and reconductor the TGN–MFA 66kV line, primarily because it still has the highest NPV. The estimated cost has increased by 31% to $40.2 million. The economic timing is identified by AusNet as 2030 from its economic modelling.[62]

60 EDPR Revised Proposal 2027-31 -Dec2025_PUBLIC. AusNet. Table 5-30.

61 AusNet – Augment East Gippsland 66kV Loop DPAR – 28112025 – PUBLIC. Page 4.

62 AusNet – Augment East Gippsland 66kV Loop DPAR – 28112025 – PUBLIC. Figure 15.

Figure 4.3: Location of high-capacity (blue) and Low capacity (red) lines in the East Gippsland 66kV network loop



Source: Augment East Gippsland 66kV Loop DPAR – PUBLIC, Figure 5
MWTS Morwell Terminal Station; TGN Traralgon; SLE Sale; MFA Maffra; BDL Bairnsdale; NLA Newmerella; CNR Cann River; BPS Bairnsdale Power Station; BDSS Bairnsdale switching station

208. AusNet has rejected the AER's application of a lower demand scenario.

Our assessment

Loop thermal overloading and voltage collapse persist as the case for action in the RRP

209. As with the RP, the identified need is to address the risk of significant load shedding needed during the peak demand period to prevent voltage collapse and thermal overload. Coincidental loading is forecast by AusNet to exceed the 66kV loop's N capacity of 144 MVA by FY27 (PoE50 demand) and exceed the voltage collapse limit of 162 MVA by FY26 (PoE10 demand). As with AusNet's RP analysis, the worst-case N-1 condition is a MWTS–Sale ZSS (SLE) outage and the loop's thermal limit of 86.3 MVA would be exceeded under PoE50.

AusNet has included generation projects in evaluating future operating conditions

210. In its original analysis, AusNet assumed that the Bairnsdale Power Station (BPS), which is connected to the Bairnsdale Switching Station (BDSS) is not available to assist 'on demand' to manage network contingency events. It has maintained this position in its RRP. We asked AusNet to advise us of the latest position with respect to the availability of BPS to assist with off-loading the loop when required, even as a means of deferral of the proposed network augmentation. We summarise the response as follows:[63]

- In 2022, AusNet [redacted] AusNet [redacted] AusNet further notes that EAR analysis indicates that generation-based support would be required for at least six months, significantly increasing overall costs.
- During periods of high temperature, AusNet had to undertake operational measures to avoid voltage collapse and thermal overloading. BPS was not generating at times when its output could have mitigated the issues. These measures were not required if BPS generation was available.
- The RIT-D process for assessing the options to alleviate the East Gippsland 66kV loop issues (and which concluded in May 2025) did not elicit any non-network solutions from the market.

63 IR#079 AusNet Response – 13022026 – CONF. Pages 26-29.

211. Based on this response we are satisfied that it is reasonable not to include a contribution from BPS in AusNet's options analysis any further.

Fraser Solar Farm and Fulham Solar and BESS Plant included in RRP modelling

212. AusNet states that it has considered two generation projects in its updated modelling:[64]

- Fraser Solar Farm (77 MW), which is an 'anticipated' project
- Fulham Solar and Battery Energy Storage System (BESS) Plant (80 MW solar and 64 MW / 128 MWh battery) which is a 'committed' project.

213. The network constraints occur at night according to AusNet's business case and so AusNet has only included the Fulham BESS in the base case of its economic analysis.[65] Given the assumed mean time to restore a 66kV line in the loop is between one and two hours,[66] we consider exclusion of solar contributions to be a reasonable assumption.

214. The Fulham BESS output is modelled by AusNet as a dependable generation source based on 90th percentile generation rates derived from five years of market modelling using PLEXOS simulations. In doing so, AusNet models the Fulham BESS as contributing to resolve unserved energy in its do-nothing scenario.[67] However, AusNet also states that:[68]

> *'AusNet does not have a network support agreement with the Fulham generation facility. Consequently, there is no guaranteed availability during periods when unserved energy risk is highest. The modelling reflects this (i.e.: Modelling assumes Fulham is a market participant at its will and therefore AusNet did not include a network support payment/cost in the modelling).'*

215. We consider this to be a reasonable approach given the Fulham BESS is a committed project due to be commissioned in 2028.

216. AusNet observes that there is considerable uncertainty regarding the actual commissioning of these generators and if they are delayed, *the impact on reliability could be substantial in the absence of remedial action*.[69]

The options considered now include augmentation of the MWTS–TGN No 1 and No 2 66kV lines

217. AusNet considered five options to provide additional network capacity in its original business case and economic model, selecting Option 1 (new CBTS–OFR 66kV line) primarily because it had the highest NPV.

218. Table 4.7 summarises the options analysis from the updated business case and economic model prepared to support the RRP. The options have each been modified in the RIT-D DPAR to include upgrading the MWTS–TGN 1 and 2 66kV lines. As discussed above, these two lines were assumed by AusNet in its Options Screening Report (OSR) to be upgraded as part of a proposed 'Connection Enablement' project but which was not included in the AER's draft decision.

64 AusNet – Augment East Gippsland 66kV Loop DPAR – 28112025 – PUBLIC. Page 4.

65 AusNet – Augment East Gippsland 66kV Loop DPAR – 28112025 – PUBLIC. Page 4.

66 AusNet – FPAR Augment Eastern Cranbourne 66kV Loop CBTS-OFR line – 26112025 – PUBLIC. Page 14. Following a thermal overload, voltage collapse, or other trip mechanism.

67 AusNet – Augment East Gippsland 66kV Loop DPAR – 28112025 – PUBLIC. Page 12.

68 AusNet – Augment East Gippsland 66kV Loop DPAR – 28112025 – PUBLIC. Page 12.

69 AusNet – Augment East Gippsland 66kV Loop DPAR – 28112025 – PUBLIC. Page 4.

Table 4.7: East Gippsland 66kV Loop - summary of AusNet's options analysis ($m, real June 2024)

Option	Capex	NPV
Do nothing	0.0	0.0
Option 1 (preferred): Augment the MWTS–TGN No.1 and No.2 66kV lines with 19/4.75 conductor & reconductor the entire TGN-MFA 66kV line	40.43	244.6
Option 2: Augment the MWTS–TGN No.1 and No.2 66kV lines with 19/4.75 conductor & construct new TGN-SLE 66kV line	65.82	219.5
Option 3: Augment the MWTS–TGN No.1 and No.2 66kV lines with 19/4.75 conductor & establish a TGN-SLE/MFA 66kV line	58.39	230.5
Option 4: Augment the MWTS–TGN No.1 and No.2 66kV lines with 19/4.75 conductor & construct a 30 MW/150 MWh BESS at Bairnsdale Switching Station (BDSS)	78.12	217.5

Source: Augment East Gippsland 66kV Loop DPAR – 28112025 – PUBLIC, Table 4

219. AusNet states that without the augmentation of the MWTS–TGN lines, enhancing the TGN–MFA line does not increase the overall loop capacity due to thermal limitations on the MWTS–TGN segment.

220. Option 1 has the highest NPV according to AusNet's modelling. Based on AusNet's comparative analysis, we are satisfied that this is the prudent option.

The economic timing is deferred to 2031

221. The introduction of the Fulham BESS has an impact on EUE, reducing it, as shown in Figure 4.4. This delays the economic timing to FY30, as shown in Figure 4.5.[70]

222. AusNet advised that if the impact of the assumed summer/winter PV factors are removed, the economic timing is deferred to 2031. Furthermore, in AusNet's response to an information request regarding errors in the EAR spreadsheet, AusNet advised that whilst correcting the error does not change the ranking of the options, the economic timing is deferred until 2031.[71] We therefore propose that the project should not be delivered until 2031, based on current assumptions.

223. We also considered the sensitivity of the economic timing to key parameters in AusNet's updated economic model. For the low demand scenario (base case demand x 90%), the economic timing for Option 1 is deferred until 2036,[72] noting that this result is without correcting for the modelling error described above, which we assume would contribute to further deferral of the economic timing. The economic timing remains very sensitive to the assumed demand. Similarly, removing the impact of the PV factor, under the low demand scenario, the economic timing is deferred to FY38.[73]

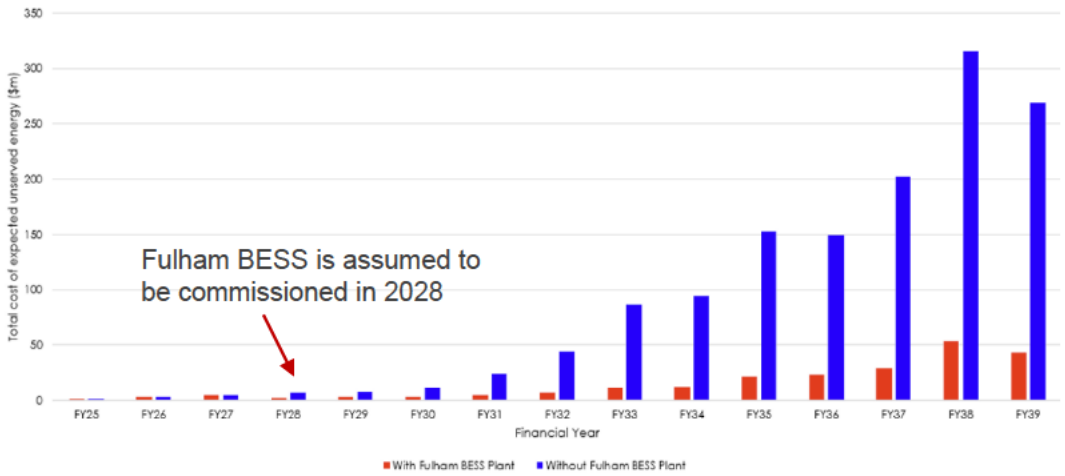
70 AusNet – Augment East Gippsland 66kV Loop DPAR – 28112025 – PUBLIC. Figure 15.

71 IR079 AusNet Response – 13022026 – CONF. Page 16.

72 AusNet – Augment East Gippsland 66kV Loop economic model – 01122025 – CONF, worksheet 3.2.5 NPV (low demand).

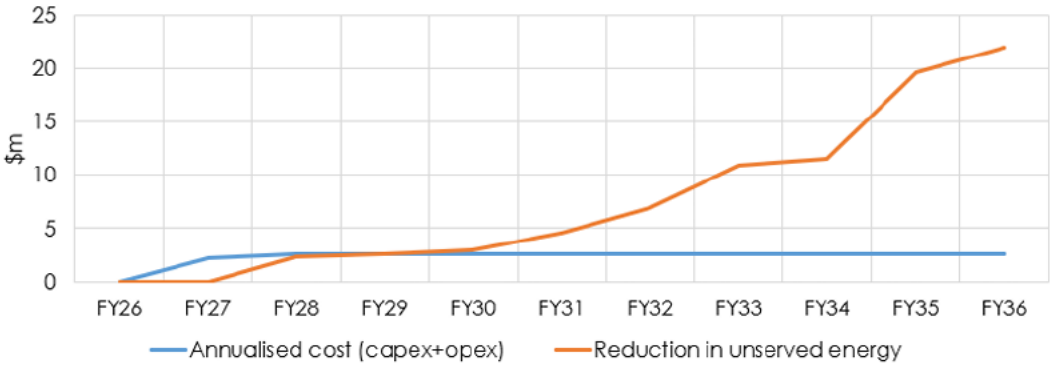
73 IR069 – Response to EMCa questions 1-9 23012026 – CONF. Page 14.

Figure 4.4: Expected Unserved Energy – East Gippsland 66kV loop – with and without Fulham BESS



Source: AusNet – Augment East Gippsland 66kV Loop DPAR – 28112025 – PUBLIC, Figure 7

Figure 4.5: East Gippsland 66kV loop – economic timing ($m, real June 2024)



Source: AusNet – Augment East Gippsland 66kV Loop DPAR – 28112025 – PUBLIC, Figure 15

Cost estimate has increased due to scope change

224. The RRP cost estimate for the project is higher than the January 2025 estimate that AusNet submitted with its RP primarily due to the addition of the MWTS–TGN scope of works which includes reconductoring 5km with 37/3.75 AAC.[74] As discussed above, upgrading the MWTS–TGN line was included in the RP as a separate project which was not approved in the AER's draft decision. The benefits associated with the augmentation of the TGN–MFA 66kV line can only be realised with the additional scope of works.

225. We are satisfied with this explanation.

Summary of findings

226. We consider that Option 1 is the prudent approach to addressing the expected thermal overload and voltage collapse scenarios.

227. We are satisfied that the proposed capex represents a reasonable estimate at this stage of the project development lifecycle, with the exception of the combination of allowances that it has not sufficiently justified, as discussed in Section 3.

228. The economic timing for the work is FY31. We therefore propose a one-year delay to AusNet's proposed expenditure profile, as the project is currently programmed for completion in FY30.

74 All Aluminium Conductor

229. We observe that with the low demand scenario, the economic timing is deferred until well into the subsequent RCP.

4.3.6 Assessment of new 20/33 MVA Transformer at Wonthaggi (WGI) Zone Substation

Overview of RP program and AER's draft decision

230. Demand growth in the Wonthaggi and surrounding areas was expected to increase consistently over the next decade because of population growth and electrification of transport and households. AusNet proposed installing a new 20/33MVA 66/22kV transformer at WGI ZSS in the next RCP to replace one of the existing 1960s vintage 10/13.5 MVA 66/22kV transformers to provide more supply capacity.

231. Table 4.8 summarises the proposed expenditure in AusNet's RP and the AER draft decision for the WGI transformer project both in terms of the quantum of reduced expenditure and the rationale for doing so. The key issue was the inclusion of 'contingency risk allowance.'

Table 4.8: AusNet RP and AER draft decision – new WGI transformer ($m, FY26)

Project	AusNet Proposal	AER draft decision	AER reasons
WGI new Tx	12.6	11.5	The proposed investment is reasonable. Our alternative estimate reflects the removal of the contingency risk allowance.

AER draft decision, Attachment 2 – Capital expenditure, Table A.2

Overview of RRP program

232. The updated business case incorporates:[75]

- Higher capex estimate 'due to cost pressures and the refinement of our scope of work'
- Updated demand forecast incorporating 'the latest 2024/25 summer actuals, AEMO's latest PV and EV data, residential batteries, business electrification and energy efficiency'
- Updated EUE reflecting gross energy at risk instead of net energy at risk
- Load transfers reduced to 0MVA
- Changes to the transformer cyclic ratings
- Downgrading the contribution from Wonthaggi wind farm (WWF) from 7.2MW to '*less than 0.1MW*.'[76]

233. AusNet's preferred option remains replacing a 10/13MVA transformer with a 20/33MVA transformer at a revised capital cost of $12.1 million. The economic timing identified from AusNet's modelling is 2029,[77] however AusNet proposes completing the project in FY31.

Our assessment

AusNet's preferred option remains the prudent approach

234. In our assessment of the RP equivalent project, we concluded among other things, that AusNet's range of options was reasonable. AusNet proposes the same options in the RRP, with the summary of its updated options analysis shown in Table 4.9.

75 AusNet – Install a new 20 33 MVA transformer at WGI Zone Substation – 01122025 – PUBLIC. Pages 2, 24.

76 AusNet – Install a new 20 33 MVA transformer at WGI Zone Substation – 01122025 – PUBLIC. Page 24.

77 AusNet – Install a new 20 33 MVA transformer at WGI Zone Substation – 01122025 – PUBLIC. Page 23.

Table 4.9: Summary of AusNet's options analysis ($m, real June 2024)

Option	PV Cost	NPV
Do nothing	0.0	0.0
Option 1: Replace 3 x 10/13.5 MVA Tx with 3 x 20/33 MVA Tx	25.9	20.7
Option 2 (preferred): Replace 1 x 10/13.5 MVA Tx with 1 x 20/33 MVA Tx	10.8	38.2
Option 3: Construct 2x 20/33MVA zone substation in Inverloch	40.9	2.8
Option 4: Contract network support services to defer network investment	27.6	0.0

Source: AusNet – Install a new 20 33 MVA Transformer at WGI Zone Substation – 01022025 – PUBLIC, Table 19

235. We have considered the updated economic model and the NPV analysis confirms that with the updated assumptions, Option 2 generates the highest NPVs under Base case and sensitivity scenarios.

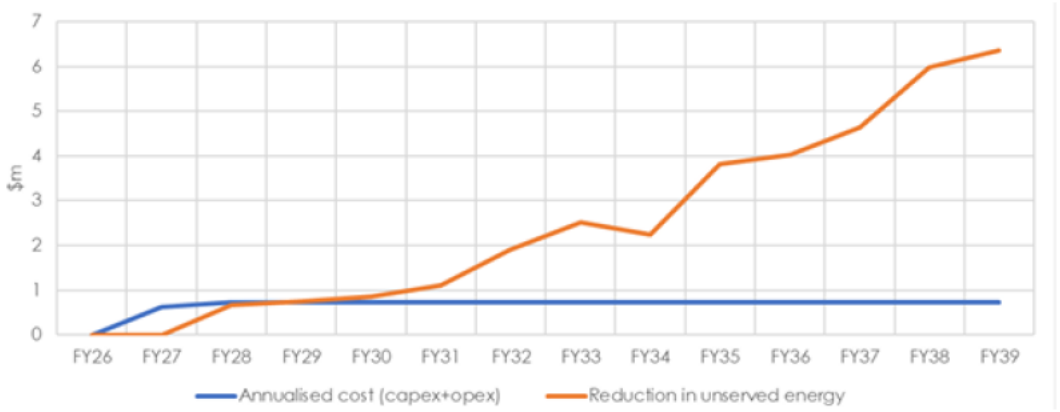
236. We therefore focus on the optimal timing of the proposed scope and the cost.

AusNet's updated demand forecast has increased considerably, increasing the EUE

237. As shown in Figure 4.6, the PoE50 and PoE10 forecasts have increased considerably, which together with the changes to the WWF contribution, load transfer, cyclic ratings, and inclusion of the PV factors, leads to a significantly higher EUE.

238. As shown in Figure 4.6, the economic timing is FY29.

Figure 4.6: WGI third transformer – economic timing – base case ($m, real June 2024)

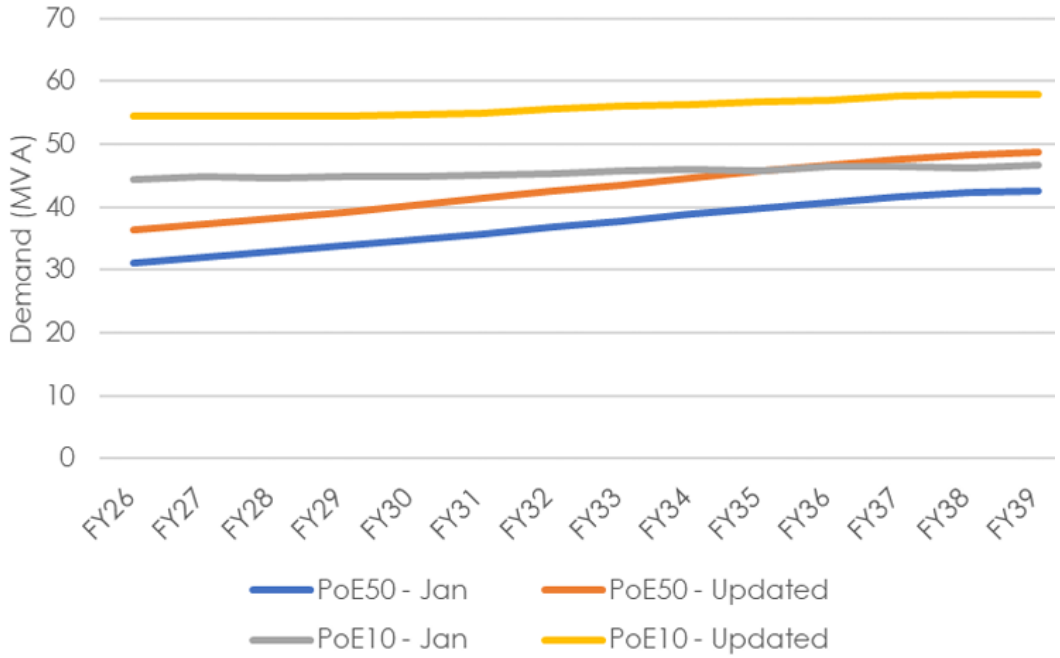


Source: AusNet – Install a new 20 33 MVA Transformer at WGI Zone Substation – 01122025 – PUBLIC, Figure 15

239. We have discussed the inclusion of PV factors in Section 3.2.3. The economic timing is deferred from 2029 to 2031 if the PV factors are set to 1.0, with all other things being equal.

240. As discussed in Section 3, AusNet's optimal timing is established by using an annualised cost derived from the PV of the capex (plus opex) which is lower than if the undiscounted capex is used. With the appropriate annualised cost, the economic timing is FY30, with all other factors unchanged, a deferral of one year from AusNet's base case.

Figure 4.7: WGI - January and updated summer demand forecasts



Source: AusNet – Install a new 20 33 MVA transformer at WGI Zone Substation – 01122025 – PUBLIC, Figure 16

Other adjustments in the RRP economic model

241. AusNet uses the AER's 2024 VCR weighted according to the WGI consumption mix,[78] which is heavily weighted to residential customers.

242. The revised and significantly lower transfer capacity of 0.0MVA to contiguous substations Phillip Island (PHI), Leongatha (LGA), and Lang Lang (LLG) is due to technical limitations which are explained in the business case. We consider that the explanation and therefore the updated transfer assumption is reasonable.

243. Changes to the transformer cyclic ratings are not explicit in the business case, however we note that the summer cyclic ratings used in the updated economic model are 55.8MVA (N) and 35.3MVA (N-1)[79] which are 10.8MVA and 5.3MVA higher than the respective ratings applied in the RP business case.[80] The higher cyclic ratings will have the effect of reducing the EUE materially, delaying the economic timing compared to the RP, all other things being equal.

244. However, AusNet has reduced the contribution of the WWF from 7.2MW in the RP economic model to '*less than 0.1MW*' because '*the ZSS historical demand profile showed that on max demand days, the WWF is often generating less than 0.1MW*.'[81] Whilst this may be the case at the peak day, the WWF is likely to make a contribution over the duration of the 4.6 months mean time to repair (MTTR) for a failed transformer(s) that AusNet has assumed in its modelling for N-1 and N-2 contingencies. We therefore consider the EUE is likely to be somewhat overstated due to the assumed 0.1MW WFF contribution. To understand the possible reliable or 'firm' contribution that the WWF could make to reducing the EUE with a less conservative assumption, we applied an annual embedded generation contribution of 3.4 MVA based on the annual average output of 30GWh p.a. reported by the owner/operator.[82] This leads to an optimum timing of 2032, although we note that the contribution may be less than average over summer. A 20% reduction in average output of the WWF results in the economic timing being in the last year of the next RCP, 2031.

78 AusNet – Install a new 20 33 MVA transformer at WGI Zone Substation – 01122025 – PUBLIC. Table 7.

79 AusNet – Install a new 20 33 MVA transformer at WGI Zone Substation – 01122025 – PUBLIC. Page 6.

80 AusNet – WGI new Tx BC – 31012025 – PUBLIC. Page 7.

81 AusNet – Install a new 20 33 MVA transformer at WGI Zone Substation – 01122025 – PUBLIC. Page 24.

82 Edlenergy.com/project/Wonthaggi (data sourced from CY2023), assuming 1.0 pf.

245. Considering reasonable variations to input assumptions, we consider that on balance, the reasonable estimate of the economic timing is 2031 with the current demand forecast.

246. We also considered AusNet's modelled low demand scenario for which the economic timing is deferred to 2033, all other things being equal, so if other parameter corrections were included, this would lead to deferral of the economic timing well into the subsequent RCP.

The revised cost is slightly lower than the RP cost

247. AusNet has reduced its cost estimate from $12.6 million in the RP to $12.1 million, citing more mature project scope. The estimate still includes the risk allowance and with the exception of this factor, for reasons we discuss in Section 3, we consider the revised cost estimate to be reasonable.

Summary of findings

248. AusNet has updated a number of factors which together result in 2029 as the economic timing of the preferred Option 1 to replace a 10/13.5MVA 66/22kV transformer at WGI. We consider this to be the prudent option.

249. AusNet has revised the forecast cost to $12.1 million by reinstating the risk allowance and accounting for changes to scope and unit cost uplifts, but which is slightly lower than its RP estimate. With the exception of the allowances that we discuss in Section 3.2.3, we consider the cost estimate to be reasonable.

250. The economic timing is likely to be 2031 with: (i) the reinstatement of some contribution from the WWF; (ii) the correction of the annualised cost calculation; and (iii) the correction to errors in AusNet's EAR derivations.

251. We also observe that the economic timing is very sensitive to the demand forecast, with the low demand scenario (90% of the base case demand) deferring the economic timing well into the subsequent RCP.

4.3.7 Assessment of project to install a new 22kV distribution feeder (WOTS21)

Overview of RP program and AER's draft decision

252. Demand growth in the Wodonga region was expected to increase consistently over the next decade because of population growth and electrification of transport and households. AusNet proposed installing a new 22kV feeder from Wodonga Terminal Station (WOTS) by splitting the existing WOTS25 feeder in two to manage the risk of involuntary load shedding and to enable connection of new customers.

253. Table 4.10 summarises the proposed expenditure in AusNet's RP and the AER's draft decision for the feeder project both in terms of the quantum of reduced expenditure and the rationale for doing so. The key issue was the inclusion of a contingency risk allowance.

Table 4.10: AusNet RP and AER draft decision – new WOTS21 22kV feeder ($m, FY26)

Project	AusNet Proposal	AER draft decision	AER reasons
Install a new 22kV distribution feeder (WOTS21)	7.6	6.7	The proposed investment is reasonable. The reduction reflects the removal of risk allowance. Our alternative estimate reflects the removal of the contingency risk allowance.

Source: AER draft decision, Attachment 2 – Capital expenditure, Table A.2

Overview of RRP program

254. The updated business case incorporates:[83]

- A lower capex estimate due to refinement of the scope and despite an increase in labour and material costs
- An updated demand forecast incorporating 'the latest 2024/25 summer actuals, AEMO's latest PV and EV data, residential batteries, business electrification and energy efficiency'
- An updated EUE reflecting gross energy at risk instead of net energy at risk.

255. AusNet's preferred option remains splitting WOTS25 feeder to create WOTS21 feeder at a revised capital cost of $6.4 million. The economic timing identified from AusNet's modelling is FY30.[84]

Our assessment

AusNet's preferred option remains the prudent approach

256. In our assessment of the RP equivalent project we concluded, among other things, that AusNet's range of options was reasonable.

257. AusNet has proposed the same four options in addition to the 'no proactive intervention' base counterfactual, with the updated cost benefit analysis summarised in Table 4.11.

Table 4.11: New WOTS21 feeder – summary of cost-benefit options analysis ($m, real June 2024)

Option	PV Cost	NPV
Do nothing	0.0	0.0
Option 1: WOTS25 22kV feeder upgrade to a higher rating	12.5	337.6
Option 2 (preferred): Construct a new 22kV feeder by splitting the existing WOTS25 into two feeders (new WOTS21 feeder)	5.6	360.3
Option 3: Construct 5MW/10MWh Battery Energy Storage System (BESS)	20.2	342.0
Option 4: Contract external network support services to defer network investment	22.9	0.0

Source: AusNet – Install a new 22kV distribution feeder (WOTS21) – 0112205 – PUBLIC, Table 21

258. We have considered the updated economic model and the NPV analysis confirms that with the updated assumptions, Option 2 in the business case still generates the highest NPVs under the base case and sensitivity scenarios.

259. We therefore focus on the optimal timing of the proposed scope and the cost.

The revised economic timing is FY30

260. The updated summer peak demand forecast for the WOTS25 22kV distribution feeder are somewhat higher than applied in the RP modelling, but these increases are largely offset by the decreases in the winter PoE.[85] The economic timing is now determined to be 2030, which is still within the next RCP, as shown in Figure 4.8.

261. To assess the sensitivity of the economic timing to favourable variances, we used AusNet's modelled results which show that with the low demand case (90% of the central case), the economic timing is deferred until 2034. The use of discounted annualised cost does not affect the outcome.

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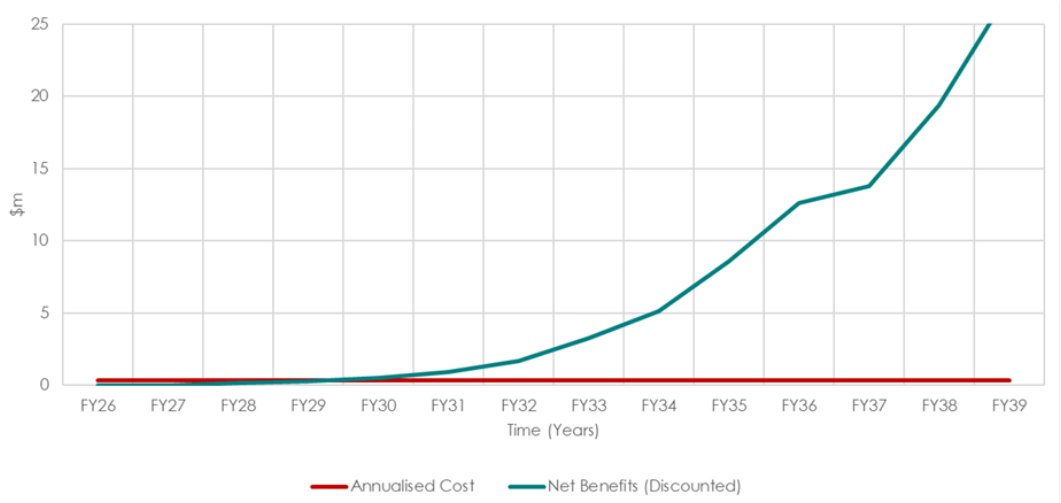
83 AusNet – Install a new 22kV distribution feeder (WOTS21) – 01122025 – PUBLIC. Page 2.

84 AusNet – Install a new 22kV distribution feeder (WOTS21) – 01122025 – PUBLIC. Table 24.

85 Derived by EMCa from AusNet – Install a new 22kV distribution feeder (WOTS21) – 01122025 – PUBLIC. Tables 25, 26.

Figure 4.8: New WOTS21 feeder – economic timing ($m, real June 2024)



Source: AusNet – Install a new 22kV distribution feeder (WOTS21) – 01122025 – PUBLIC. Figure 11.

The updated cost estimate is slightly lower than in the RP

262. AusNet has reduced the cost from its RP business case by $1.2 million (16%) to $6.4 million by refining the scope and after incorporating increased unit costs.[86] With the exception of the issues discussed in Section 3.2.3, we consider this to be a reasonable estimate.

Summary of findings

263. AusNet has selected the prudent solution and has reduced the cost from its RP by 16%. With the exception of AusNet's assumed cost allowances as discussed in Section 3, we consider the estimate to be reasonable.

264. With the base case demand forecast, the economic timing is FY30. If the low demand scenario is applied, the economic timing is deferred until 2034, which would defer all the proposed capex to the subsequent RCP.

4.3.8 Assessment of new 22kV distribution feeder (WGL31) & New Switchboard at WGL ZSS

Overview of RP program and AER's draft decision

265. Demand growth in the Baw Baw region was expected to increase steadily over the decade from 2025 because of population growth and electrification of transport and households. AusNet proposed constructing a new 22kV feeder (WGL31) from the 66/22kV Warragul zone substation (WGL) utilising the existing WGL24 22kV feeder route. The economic timing for the project from AusNet's model was 2029.

266. Table 4.12 summarises the proposed expenditure in AusNet's RP and the AER's draft decision for the project both in terms of the quantum of reduced expenditure and the rationale for doing so. There were multiple issues that led to the AER's draft decision.

[86] AusNet – Install a new 22kV distribution feeder (WOTS21) – 01122025 – PUBLIC. Page 2.

Table 4.12: AusNet RP and AER draft decision – new WGL31 feeder and new switchboard ($m, FY26)

Project	AusNet Proposal	AER draft decision	AER reasons
Install a new 22kV distribution feeder (WGL31)	19.1	0.0	AusNet has not adequately considered all available cost-effective options, and EMCa has identified weaknesses in the robustness of the Expected Unserved Energy forecasting. Additionally, the justification for the proposed investment timing is insufficient

Source: AER draft decision, Attachment 2 – Capital expenditure, Table A.2

Overview of RRP program

267. The updated business case identifies the following 'key updates' since the January 2025 submission:[87]

- A higher capex estimate due to considerable changes to the scope and an increase in labour and material costs
- An updated demand forecast incorporating '*the latest 2024/25 summer actuals, AEMO's latest PV and EV data, residential batteries, business electrification and energy efficiency*'
- An updated EUE reflecting gross energy at risk instead of net energy at risk.

268. AusNet's preferred option has changed significantly. It now proposes constructing a new 22kV feeder by utilising the existing WG11 route and constructing a new 22kV switchroom. The revised capital cost is $32.8 million. The economic timing identified from AusNet's modelling remains as FY29.[88]

Our assessment

WGL13 remains as the critical feeder in the WGL supply area

269. AusNet continues to identify WGL13 as the critical feeder of the nine 22kV feeders supplied out of WGL. The forecast PoE50 summer peak demand by FY31 is 21.1MVA,[89] a substantial 24% increase from the RP forecast.[90] All other things being equal, we would expect this to bring forward the economic timing due to higher EUE.

270. The updated forecast demand for WGL13 illustrated in Figure 4.9 shows a step increase in FY29. AusNet notes that it has received:[91]

> *'...three industrial/commercial customer applications in the cities of Warragul and Drouin in the last year, resulting in a [sic] 11 MVA of additional load, two Electrical Vehicle (EV) charging stations (4 MVA), shopping precinct (1 MVA) and a connection application for the new hospital (6 MVA). All these loads are expected to be fully operational by 2029. Several connection inquiries have also been received for connecting industrial/commercial and residential loads in the area supplied by the same feeders.'*

271. Although not stated explicitly, we infer that a significant portion of the anticipated connections are to be supplied from WGL13. Reviewing the demand forecast is not within our scope, however we observe that the identified new loads are at the application stage, which is not as firm as 'committed' connections/loads.

87 AusNet – Install a new 22kV distribution feeder (WGL31) & New Switchboard - 01122025 – CONF. Page 2.

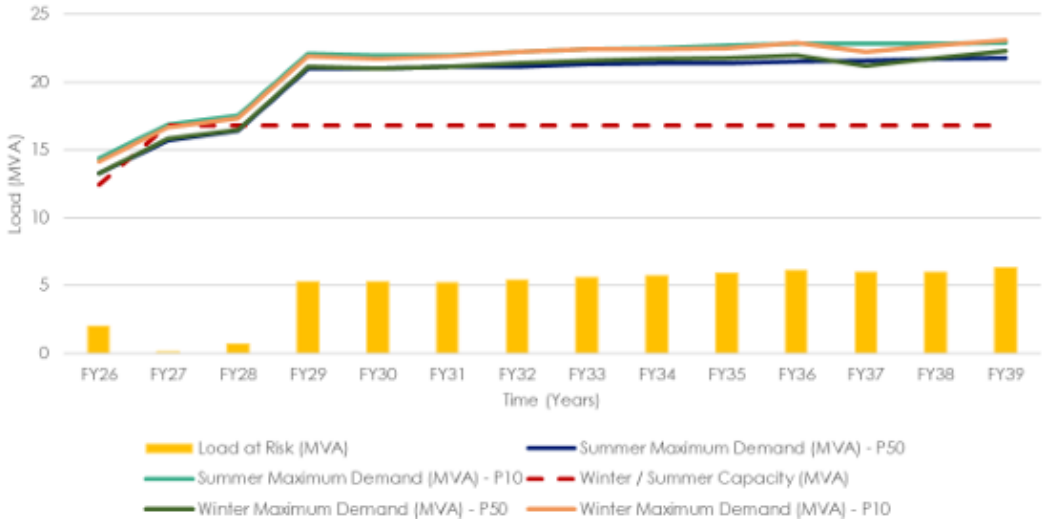
88 AusNet – Install a new 22kV distribution feeder (WGL31) & New Switchboard - 01122025 – CONF. Table 22.

89 The summer 10PoE forecast for FY31 is 22.2MVA, a 21.5% uplift.

90 AusNet – Install a new 22kV distribution feeder (WGL31) & New Switchboard - 01122025 – CONF. Table 23.

91 AusNet – Install a new 22kV distribution feeder (WGL31) & New Switchboard - 01122025 – CONF. Page 6.

Figure 4.9: WGL13 – Load at risk



Source: AusNet – Install a new 22kV distribution feeder (WGL31) & New Switchboard - 01122025 - CONF, Figure 6

AusNet's has increased the capacity of WGL and the WGL13 feeder, however it is not sufficient to meet future demand growth

272. AusNet states that it is undertaking two relevant projects in the current RCP to help manage supply risk: [92]

- The capacity of WGL is being upgraded by replacing the four WGL 10/13.5MVA transformers with two new 20/33MVA transformers by the end of 2026
- Uprating the existing WGL13 feeder by 4.4MVA, which is shown in Figure 4.9.

A non-network solution has been installed to offload the WGL12 22kV feeder, however it does not provide an option to offload WGL13

273. AusNet also states that it recently commissioned a 4.9MW/7.5MWh battery in Longwarry to provide non-network support to the WGL12 feeder under a three year contract, commissioned in 2023. AusNet states that the WGL12 feeder is forecast to exceed its rating during the next RCP and *'[as] a result, offloading WGL13 to WGL12 to leverage the Longwarry Battery is not considered practically feasible.* [93] This is likely to be a reasonable assumption.

The PV benefits have reduced in the updated business case/economic model, but the economic timing remains as 2029

274. Despite the significantly higher demand forecast, AusNet's revised modelling generates lower total benefits for all options, with the benefit for Options 1 and 2 at $255.4 million, down from $293.5 million in the RP. The source of the reduction is not apparent from the RRP, however at this level the benefit to cost ratio remains strong. Even if the study period is reduced to 20 years to improve the certainty about future benefits somewhat, the NPV remains strongly positive.

The economic timing is sensitive to demand growth

275. Under AusNet's base case scenario, the economic timing is FY29 which is when it plans to complete the new feeder. Under AusNet's low demand scenario (90% of base case

92 AusNet – E@R WGL13 V2.7 – 01122025 – PUBLIC, Capacity.

93 AusNet – Install a new 22kV distribution feeder (WGL31) & New Switchboard - 01122025 – CONF. Page 7.

demand), the economic timing is deferred by four years to FY33[94] which illustrates the sensitivity to the assumed demand growth.

The cost of the network and non-network options have more than doubled in some cases since the RP

276. As shown in Table 4.13, the PV of the estimated capital cost for the four options considered by AusNet in its original and updated business cases and economic models have increased significantly.

Table 4.13: Comparison – Initial RP business case and updated RRP business case ($m, real June 2024)

	RP		RRP	
Option[95]	PV cost	NPV	PV cost	NPV
Do nothing	0.0	0.0	0.0	0.0
Option 1 (preferred): Construct a new 22kV feeder by utilising the existing WGL11 route + 22kV switchroom	16.9	276.6	31.4	224.0
Option 2: Construct a new 22kV feeder by utilising the existing WGL24 route + 22kV switchroom	12.9	280.6	36.0	219.4
Option 3: Construct a 5MW/10MWh battery energy storage system	16.8	269.1	33.8	221.0
Option 4: Contract external network support services to defer network investment	118.0	59.0	225.6	0.0

Source: New 22kV distribution feeder (WGL31) BC – 31012025, Table 1 and New 22kV distribution feeder (WGL31) & New Switchboard – 01122025 – CONF, Table 1

277. The preferred Option 1 comprises a new feeder to offload the existing WGL13 feeder and to provide additional support to WGL12, WGL21, and WGL24 22 kV feeders, which are also close to being constrained. The approximate route length of the overhead 22kV feeder from WGL station is 10.6 km. As for the new switchroom, AusNet states that *'[all] 22kV feeder bays in WGL station are utilised to supply distribution feeders, with no spare bays available. An extension of the busbar to accommodate a new WGL31 feeder bay will be required, coupled with the installation of a new circuit breaker and a new feeder exit cable of 500 metres.* [96]

AusNet considered other options but did not include them in the economic analysis

278. In addition to the options identified in Table 4.13, the following options were considered by AusNet but not progressed:

- A WGL13 feeder exit cable upgrade to a higher rating – not progressed because of cost and because WGL13 shares the same route initially as WGL12
- Large area reconfiguration and building additional ties – not progressed because the other feeders in the area are capacity constrained
- Build a new zone substation in Longwarry – not progressed because the decision had already been made to increase the capacity of WGL (meaning there will be sufficient capacity at the zone substation level)

94 AusNet – Install a new 22kV distribution feeder (WGL31) & New Switchboard at WGL ZSS economic model – 01122025 - CONF, 3.2.5 NPV (low demand).

95 Descriptors are from RRP business case.

96 AusNet – Install a new 22kV distribution feeder (WGL31) & New Switchboard – 01122025 – CONF. Page 14.

- The alternative, low-cost option of consolidating feeders to release a feeder bay for the new 22kV feeder is not recommended due to reliability concerns.[97]

279. With the exception of the last option in this list, we consider that the other options are unlikely to be superior to AusNet's preferred option. We consider the consolidation option further below.

AusNet considered one consolidation option but did not assess another related approach

280. In its revised business case, AusNet dismisses the low-cost option of consolidating feeders to release a feeder bay for the new 22kV feeder, stating that *'[t]he practice of piggybacking or dual glanding where two feeders are connected through a single circuit breaker is not considered an acceptable design solution due to its adverse impact on system reliability.*[98]

281. AusNet responded to an information request which explored AusNet's justification for rejecting the option on the grounds of reliability further. In summary AusNet's response is:[99]

- The two piggyback feeders would result in approximately 3,715 customers supplied from one CB position, with an aggregate feeder length of approximately 214 km
- With piggyback arrangements faults, maintenance activities, or protection operations on one circuit can result in simultaneous or cascading outages for customers supplied via the piggybacked configuration; such an outcome compromises network resilience, increases the risk of widespread outages, and undermines fault isolation protocols
- Such a configuration would also materially reduce operational flexibility
- Whilst it has three such feeders (out of 350) left in its network it has removed two and it intends replacing the remainder when a feasible opportunity arises, consistent with its Distribution Network Planning Guidelines and Standards Section 7.1.2
- The additional proposed switchboard will facilitate the connection of the proposed demand-driven new feeder and enable efficient connection of future block load customers that would trigger the need for new feeders from WGI.[100]

282. However, we consider that:

- Dual glanding or piggybacking is technically feasible and is a common feature in DNSP networks throughout the NEM and in WA
- A similar option that has not been considered by AusNet is sharing a capacitor bank between the new feeder and the capacitor bank at WGL. There is a dedicated bus breaker for the 22kV capacitor bank and a circuit at the cap bank itself.[101] This means that the new feeder could be connected to WGL23. Protection arrangements are required to ensure that the feeder does not trip for capacitor bank faults, and
- We estimate the incremental cost of the new switchboard over the dual glanding option is significant.

283. Whilst a switchboard may be required at some time in the future, we consider that the relatively large incremental cost over the dual glanding solution means that dismissing the option on reliability grounds needs to be economically justified. AusNet has not provided such justification.

97 AusNet – Install a new 22kV distribution feeder (WGL31) & New Switchboard – 01122025 – CONF. Pages 12,16.

98 AusNet – Install a new 22kV distribution feeder (WGL31) & New Switchboard – 01122025 – CONF. Page 16.

99 AusNet – Install a new 22kV distribution feeder (WGL31) & New Switchboard – 01122025 – CONF. Pages 18-20.

100 Which AusNet considers highly likely to be required within the next five years but has not included in its RRP.

101 Service constraints at Warragul (WGL) Zone Substation Regulatory Investment Test for Distribution Final Project Assessment Report, Figure 2

The option of staging the scope under the preferred option was explored

284. AusNet responded to an information request about whether under its preferred Option 1, phasing of the substation works after the feeder was established was considered. In summary, AusNet states:[102]

- The reasons outlined in response to the question regarding piggybacking the circuit breakers, discussed above, apply
- Installing the new switchroom and the associated feeder reconfiguration must be undertaken concurrently or the minimum reliability benchmarks applicable to the feeders would not be achieved, and bus loading would not adequately managed (risking overloading the existing bus infrastructure).

285. Therefore, AusNet concluded that '*a staged or partial implementation was not considered a prudent or efficient alternative, as it would fail to address the underlying constraints and could introduce additional operational and reliability risks*.'[103]

286. We are satisfied with this response although we consider Option 3 further as an alternative to Option 1.

The cost has increased for all options for a variety of reasons

287. To help understand the drivers of the significant cost uplift from the RP, we considered the changes to the scopes of work for the RRP, which are summarised as follows:[104]

- Option 1: added WGL switchroom to accommodate the new primary equipment; added a new line voltage regulator; omitted the capacitor bank specified in the RP
- Option 2: added WGL switchroom to accommodate the new primary equipment; the new feeder backbone is longer (8.7km vs 5.5km) and is along a different path; added reconductoring of 6.7km of WGL24 feeder; omitted a switch
- Option 3: added a further BESS (FY39) and a replacement BESS (FY42) for the initial unit
- Option 4: no apparent change to the scope however the cost estimation methodology has changed - the cost of the demand management option is defined as the dollar value difference between the "Do Nothing" scenario and the residual supply risk under the demand management option.[105]

288. We are satisfied that this explains the reason for the cost uplift adequately for each option, however, as discussed below, we asked for more detail for Options 1 and 3.

More detail on the cost uplift for the preferred Option 1 was provided by AusNet

289. In response to an information request, AusNet expanded on the reason for the cost uplift for the preferred Option 1 from the RP to the RRP as follows (in summary):[106]

- 'Further consideration was given to works at the station, removing the cap bank, adding station service transformers, a necessary yard extension and better planned earthworks and cabling. This has increased the primary costs by [redacted] Secondary works similarly [redacted] as scope matured.
- The largest increase in cost was to the lines component [redacted]. The RP costed 400m of underground cable with most of the feeder (~10.5km) run overhead via 19/3.25 AAC with 107 new poles and 20 replaced poles. The RRP requires approximately 13 separate runs of underground cable (~9.6km) with minimal additional overhead, and in addition to this a voltage regulator not proposed in the RP.'

102 AusNet – IR#079 AusNet Response – 13022026 – CONF. Page 18.

103 AusNet – IR#079 AusNet Response – 13022026 – CONF. Page 18.

104 Comparing scope summaries from RP business case (New 22kV distr bution feeder (WGL31) BC – 31012025) and updated RRP business case (New 22kV distribution feeder (WGL31) & New Switchboard – 01122025 – CONF).

105 New 22kV distribution feeder (WGL31) & New Switchboard – 01122025 – CONF. Page 21.

106 AusNet – IR#079 AusNet Response – 13022026 – CONF. Page 26.

290. We are satisfied with this further explanation of the key drivers of the cost uplift for Option 1.

More detail on the cost uplift for Option 3 (BESS) was provided by AusNet

291. In response to an information request, AusNet expanded on the reason for the cost uplift for Option 3 from the RP to the RRP as follows (in summary):[107]

- Its original RP assumptions were refined to align more closely with the latest CSIRO BESS cost data
- The updated estimate also incorporates more detailed and realistic allowances for balance of plant requirements, including higher expected costs for grid connection works, land acquisition, civil works, and owners' costs
- Additional BESS capacity was added to cater for future demand growth
- The shorter economic life of BESS assets, typically around 15 years, compared with approximately 50 years for a traditional distribution feeder means replacement expenditure must be accounted for within the overall financial assessment.

292. We consider AusNet's rationale for adding an additional BESS (in FY39) and a replacement for the original BESS (in FY42) to be reasonable.

293. However, we do not consider the costs assumed to be reasonable for the following reasons:

- The CSIRO BESS reference provided by AusNet[108] includes the graph reproduced in Figure 4.10; this indicates that a reasonable unit cost in FY26 for a 10MWh BESS is around $600/kWh and about $400/kWh in 2040 including the battery cost and balance of plant.[109] This would translate to:
  - $6 million for the 5MW/10MWh BESS proposed by AusNet in the next RCP; and
  - $4 million for the 5MW/10MWh additional BESS and replacement BESS.
- AusNet has allowed $19.4 million ($2024, inclusive of overheads, etc) in FY28 in its economic model for the initial BESS, which equates to approximately $17.5 million ($2024) direct capex.[110] We estimate that this implies that AusNet has included approximately $11.5 million in direct cost terms ($17.5 million - $6.0 million) for the 22kV connection and siteworks,[111] which we consider to be excessive.
- AusNet includes a further $19.4 million ($2024, including overhead etc) capex in FY39 in its economic model for the extra BESS, which we also consider to be too high for two reasons:
  - the connection cost appears excessive; and
  - it does not recognise the CSIRO battery unit cost reduction amounting to approximately $2 million (direct cost).
- AusNet includes a further $17.1 million ($2024, including overheads, etc) capex in its economic model in FY42 which we assume is for the replacement of the original BESS; however, this should only be for installing the new battery and not include the sunk costs for the 22kV cut-in works and site establishment. The cost is much higher than the CSIRO reference of $4 million.

107 AusNet – IR#079 AusNet Response – 13022026 – CONF. Page 26.

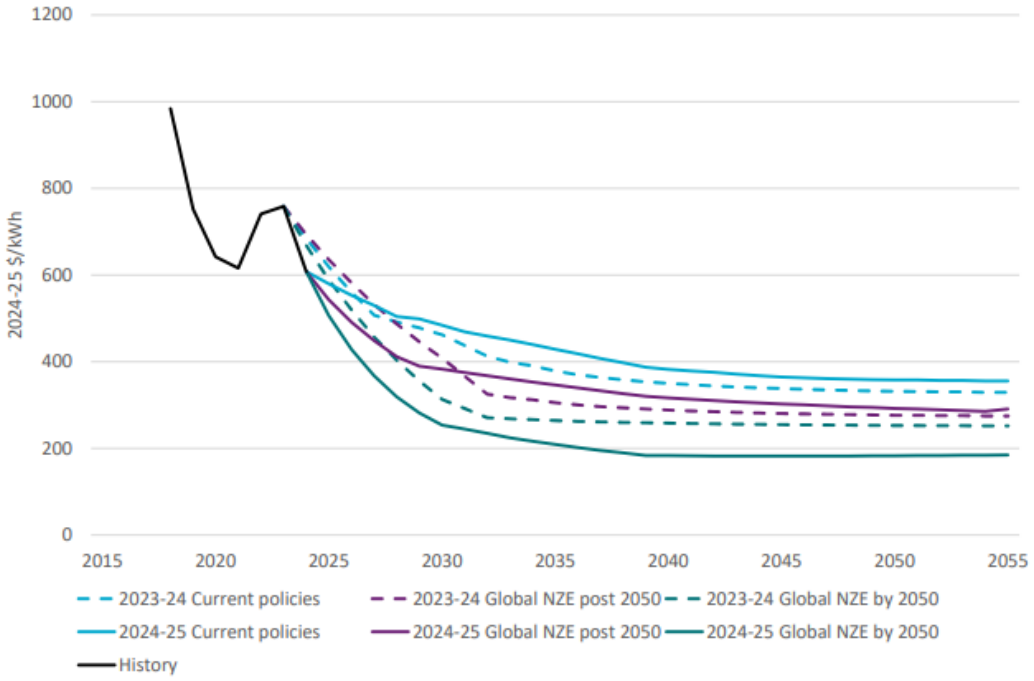
108 GenCost-2024-25-Final_20250728. CSIRO. July 2025.

109 Which we assume to include delivery and installation on the site, but not the connection works.

110 AusNet - Install a new 22kV distribution feeder (WGL31) & New Switchboard at WGL ZSS economic model.

111 Site purchase and preparation for installation of the battery plus primary and secondary plant for what we assume would be a three bay Tee to a suitable place on the 22kV feeder.

Figure 4.10: CSIRO -projected total capital costs for 2-hour duration batteries by scenario (battery and balance of plant)



Source: GenCost-2024-25-Final_20250728, CSIRO, July 2025, Figure 5-15

294. As a further cross-check we referred to 2025 AEMO cost data[112] which provides a cost estimate of $6.9 million ($5.1 million for the battery[113] and $1.8 million installation, $2024). Land purchase is an additional $0.25 million. These costs do not include the grid connection electrical infrastructure. This is slightly higher than the CSIRO data for the installed BESS. The combination of these two references indicates to us that the cost assumed by AusNet for the installed BESS of $17.5 million (direct cost, $2026) is too high.

295. Even accepting AusNet's $19.4 million ($2024 inclusive of overheads, etc) modelled cost in FY27, $17.4 million ($2024) in FY39 (i.e. adjusting for the reducing unit cost trend only) for the additional unit, and $4 million in FY42 for the replacement battery (again applying the reducing unit cost trend) results in a higher NPV for Option 3 than for Option 1.

296. Therefore, with more reasonable cost estimates for the two 5MW/10MWh BESS installations, we consider that, all other things being equal, Option 3 will have a materially higher NPV than Option 1. And based on AusNet's demand forecast, energy at risk and EUE derivations, the BESS option provides the necessary capacity injection when needed.

297. AusNet prefers Option 1 not only because, with its cost assumptions, it has the higher NPV, but also because it provides scope for catering for higher demand (i.e. above the current forecast). It refers to: (i) Department of Transport and Planning's projections; (ii) connection enquires it has received; and (iii) significant land that has been reserved for greenfield developments as indicators of demand growth above its forecast.

298. Arguably, if the demand forecast is increased, for example due to block load connections that are not factored into the current demand forecast, then Option 1 would be preferrable, however consistent with the approach taken throughout our assessment, we have based our assessment on the demand forecast as included in the economic and other models.

112 2024 Energy Technology Cost and Technical Parameter Review – Mid Size Solar PV and BESS along with Commercial/Roof Top Solar PV and community BESS Australian Energy Market Operator Reference: P527517 Revision: 3 2025-05-20. Table 5-9.

113 4.99MW/10MWh BESS interfacing with medium-voltage (MV) distribution networks at voltage levels ranging from 11 kV to 22 kV. Page 27.

Furthermore, a BESS solution provides 'option value'[114] which means that consumers may not pay a premium to manage uncertainty or risk.

299. This leads us to conclude that Option 3 is the prudent approach for regulatory allowance forecasting purposes.

Summary of findings

300. After reviewing AusNet's cost assumptions for Option 3 (construct a 5MW/10MWh BESS) we consider that the costs of the proposed works are materially overstated. We referred to AusNet's referenced cost data, other cost benchmarks, and our findings regarding AusNet's allowances that we refer to in Section 3 in forming our view.

301. Consequently, we consider that a modified Option 3, that is, applying materially reduced capital costs for each of the two BESS installations and for the future replacement battery, results in a higher NPV than for AusNet's preferred Option 1. The optimal timing of the first BESS is early in the next RCP.

302. For approximately the same cost as the BESS, a network solution based on dual glanding or piggybacking the new feeder on the capacitor bank circuit would represent a further alternative.

4.3.9 Assessment of South Eastern growth Corridor program

Overview of RP program and AER's draft decision

303. AusNet proposed a new Pakenham South ZSS (PHS) to address the growing energy demands in the Pakenham South precinct. The scope of work includes: '*• Two 33 MVA 66/22 kV transformers • Two 22 kV bus Sections, each with four 22 kV feeders • Provision for a third transformer and bus in the future, and • 22kV feeder works.*' The cost of '*running HV feeders is estimated at* [redacted][115]

304. Table 4.14 summarises the proposed expenditure in AusNet's RP and the AER's response for the project both in terms of the quantum of reduced expenditure and the rationale for doing so. The only issue expressed by the AER was the inclusion of a contingency risk allowance.

Table 4.14: AusNet RP and AER draft decision – new Pakenham South substation ($m, FY26)

Project	AusNet Proposal	AER draft decision	AER reasons
New Pakenham South ZSS	56.5	50.2	We consider the proposed investment to be reasonable. Our alternative estimate reflects the removal of the contingency risk allowance.

Source: AER draft decision, Attachment 2 – Capital expenditure, Table A.2

Overview of RRP program

305. In response to the increasing demand in the region, AusNet has prepared a development plan for the Southeastern Growth Corridor and included this with its RRP. AusNet currently has four 66/22kV ZSSs supplying customers across the greater outer Southeast of Melbourne: Clyde North (CLN), Pakenham (PHM), Officer (OFR), and Cranbourne (CRE).

306. AusNet has provided a business case, economic model and assessment of energy at risk for a new substation at PHS, in addition to proposed sub-transmission and distribution feeder developments with an outlook period to 2045.

307. AusNet refers to the Victorian Planning Authority (VPA) South-Eastern Growth Corridor Plan (2012) and two VPA tools being Precinct Structure Plans (PSPs), and Infrastructure and

[114] The value placed on retaining the flex bility regarding future investments in case of uncertainty, which in this case is locational demand growth.

[115] AusNet - New Pakenham South BC – 31012025 – CONF. Pages 21-22.

Development Staging Pan (IDSP), which indicate the staging of greenfield growth across the corridor as input for its growth assumptions.

308. The scope of work has been expanded considerably in the RRP with not only the re-scoped and re-costed PHS substation included (with four related but separately costed PHS feeder sub-projects) but as shown in Table 4.15, AusNet has included five other projects. The total revised cost is $119.3 million, with the following expanded scope:

- New CLN33, CLN32, and CRE34 22kV feeders
- CLN 3rd transformer and switchroom
- CBTS 66kV feeder rearrangement.

309. We consider the CLN 3rd transformer and switchroom project in this Section noting that the expenditure shown in Table 4.15 is the final year of a multi-year project approved and commenced in the current RCP (with a separate business case).

310. We also assess the CBTS 66kV feeder rearrangement project in this Section noting that it is the distribution component of a transmission project and is supported by AusNet in a standalone business case rather than as part of the Southeastern Growth Corridor business case.

Table 4.15: Demand-driven augex projects – Southeastern Growth Corridor ($m, June 2026)

Southeastern Growth Corridor	FY27	FY28	FY29	FY30	FY31	RCP total
Pakenham South Zone Substation Development Project	17.7	17.8	20.4	-	-	**56.0**
Pakenham South ZSS 22kV Feeder Augmentation (3 Feeders - PHS11, PHS12 & PHS13)	3.5	9.0	-	-	-	**12.5**
Pakenham South ZSS 22kV Feeder Augmentation (1 Feeder - PHS21)	-	-	-	-	4.1	**4.1**
Install a new 22kV distribution feeder (CLN33) (Delayed Project)	5.5	-	-	-	-	**5.5**
Install a new 22kV distribution feeder (CLN32)	-	-	0.9	3.2	14.7	**18.8**
CLN 3rd Transformer and Switch room (WIP)	7.6	-	-	-	-	**7.6**
Install a new 22kV distribution feeder (CRE34)	-	1.8	6.9	-	-	**8.7**
CBTS 66kV Feeder Rearrangement	0.9	5.2	-	-	-	**6.1**
Total	**35.2**	**33.8**	**28.2**	**3.2**	**18.8**	**119.3**

Source: EMCa derived from ASD – AusNet Distribution – SCS Capex Model – 011225 – CONF

Other updates from the January 2025 RP business case

311. AusNet identifies three 'key updates' in its Southeastern Growth Corridor report submitted with the RRP:[116]

- The demand forecast incorporates the latest FY25 summer actuals, AEMO's latest PV and EV data, residential batteries, business electrification and energy efficiency
- The EUE reflects gross energy at risk (instead of net energy at risk)
- More detailed options analysis to demonstrate the prudency of the preferred option.

[116] AusNet – Supply security of Southeastern Growth Corridor – 01122025 – CONF. Page 3.

312. As discussed above, there are other material changes to the RP version of the business case and economic modelling driven, in most instances, by the sharply higher demand forecast.

Related and dependent projects

313. AusNet has an in-progress RIT-D project to upgrade the CBTS–OFR 66kV loop (which we assess in Section 4.3.4). AusNet states that part of that loop supplies the Southeastern growth corridor and has determined that:[117]

- irrespective of the options considered in the Southeastern Growth Corridor report, the proposed augmentation from CBTS to OFR remains necessary, and
- the proposed CBTS–OFR sub-transmission augmentation has no impact on the 22 kV distribution network options evaluated.

314. AusNet further states that it has completed the RIT-T PACR for the Cranbourne West Supply Area and will be installing a fourth 150MVA 220/66kV transformer at CBTS in the current RCP.[118]

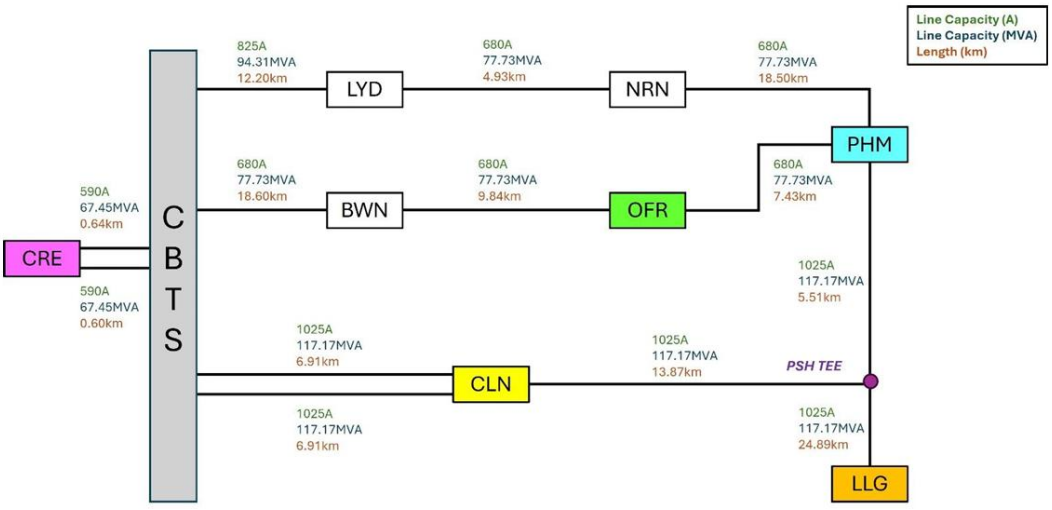
315. The CBTS 66kV feeder rearrangement project in Table 4.15 is dependent on the proposed transmission project for the Cranbourne West Supply Area proceeding. We have undertaken our assessment on the assumption that the transmission project proceeds. However, the transmission project does not form part of the business case for the 66kV feeder rearrangement project.[119] If the transmission project does not proceed, we assume that the distribution project will be deferred or otherwise changed accordingly.

Our assessment

Current sub-transmission configuration

316. Figure 4.11 shows the 66kV Southeastern Growth Corridor network. As discussed below, four of the highlighted zone substations, CLN, OFR, PHM and LLG are currently overloaded at peak times under N-1 conditions. Feeders out of these substations and from CRE substation are either overloaded now under PoE10 N conditions or are forecast to be within the next RCP.

Figure 4.11: Sub-transmission network supplying the Southeastern Growth Corridor



Source: South Eastern Growth Corridor Longterm Network Development Plan – 01122025 – PUBLIC, Figure 4.1

117 AusNet – Supply security of Southeastern Growth Corridor – 01122025 – CONF. Page 10.

118 ASD – AusNet – CBTS 66kV Feeder Rearrangement – 01122025 – CONF. Page 3.

119 CBTS 66kV Feeder Rearrangement – 01122025 – CONF. Page 3.

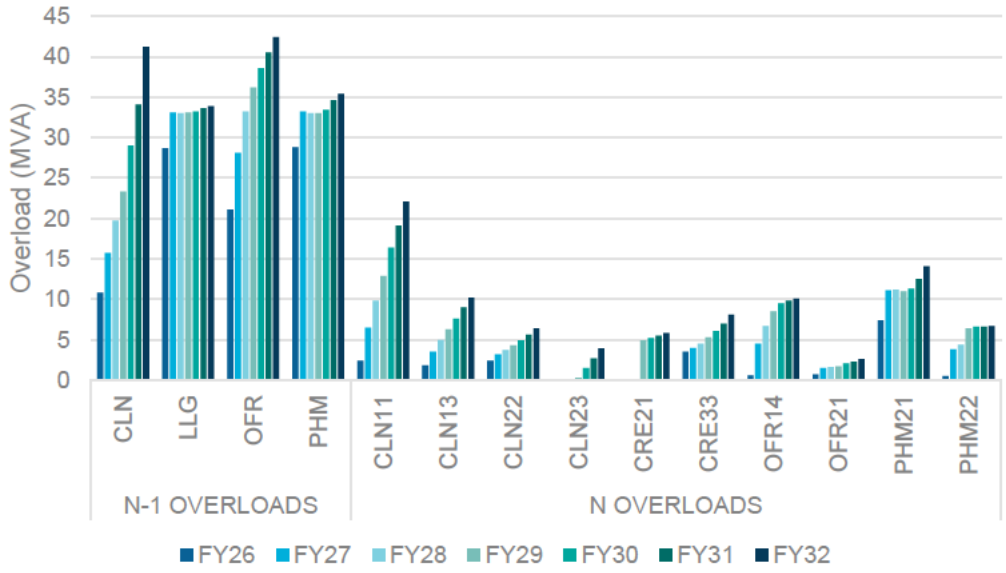
Demand forecast drives need for action

317. Figure 4.12 shows the extent of forecast N-1 overloading at PoE10 from FY27 to FY32 across four zone substations in the Southeastern Corridor, being Clyde North (CLN), Lang Lang (LLG), Officer (OFR) and Pakenham (PHM). The figure also shows the expected increase in N overloads at PoE10 across the same period for certain feeders in the region. Eight of the ten feeders are expected to be loaded at peak beyond their respective N ratings in FY26 and all are expected to be materially overloaded by FY31. CLN11 and PHM21 exhibit the greatest expected overloading in absolute terms.

318. AusNet states that for the summer of 2025/26 '*interim critical measures have been taken to manage forecast demand such as establishing new feeder tie's [sic] and utilising emergency feeder ratings for short durations.*'[120] CLN is currently being augmented with a third transformer,[121] which will mitigate the N-1 overload.

319. We are satisfied that it is prudent for AusNet to consider options to mitigate the risk of load shedding and constraints on new customer connections in the Southeastern Growth Corridor.

Figure 4.12: Do nothing base case PoE10 overloads (including available transfers and demand management)



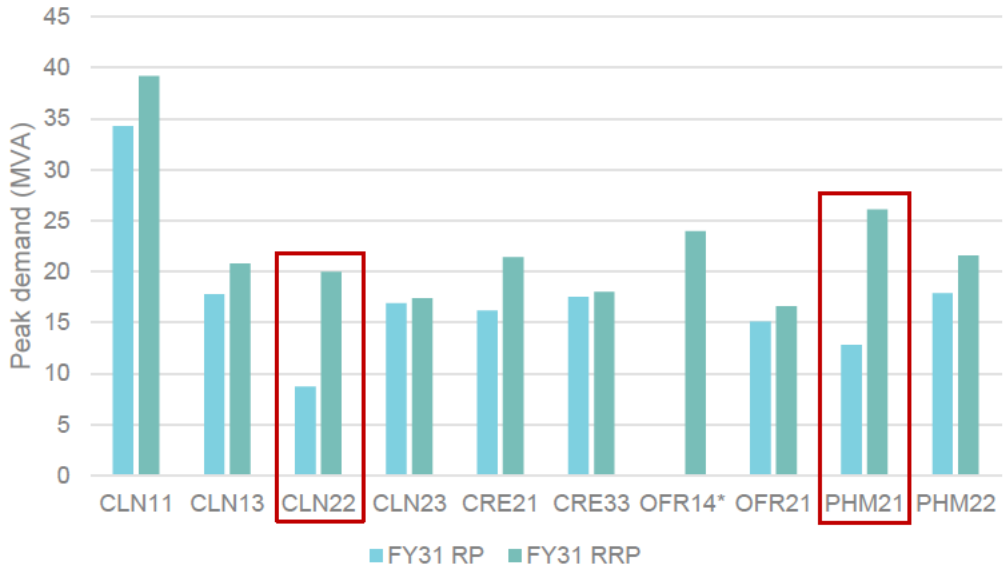
Source: EMCa analysis from AusNet – Supply security of Southeastern Growth Corridor – 01122025 – CONF, Table 1
Cyclic ratings are used for the substations

320. As shown in Figure 4.13, the demand forecast has increased significantly since the RP, particularly for the CLN22 and PHM21 feeders. Individually and collectively, these overload predictions point to significant existing and growing EAR and probabilistic EUE.

120 AusNet – Supply security of Southeastern Growth Corridor – 01122025 – CONF. Page 5

121 South-Eastern Growth Corridor Longterm Network Development Plan. Page 29.

Figure 4.13: RP versus RRP FY31 PoE10 peak demand forecasts for relevant Southeastern Corridor 22kV feeders



Source: EMCa analysis based on AusNet - Supply security of Southeastern Growth Corridor – 01122025 - CONF, Table 61
** OFR14 feeder forecast was not provided in the RP*

AusNet has identified load transfer and demand management capacity and made provision in the model for embedded generation

321. AusNet has appropriately considered the current and forecast substation/ feeder load transfer capacities[122] and demand management capacities as part of its overload assessment. Transfer capacities are assumed to contract over time, which is reasonable. LLG is identified as having no transfer capacity from FY26 and three 22kV feeders are similarly assessed as having 0.0MVA transfer capacity from FY26 (CLN22, CRE33, OFR21).

322. Demand management (DM) capacity is identified by AusNet for one substation (CLN) and one feeder (CLN11) only and we assume it is the DM on CLN11 that gives the corresponding ZSS its DM capacity. Increasing DM is considered in AusNet's option analysis which we consider below.

323. AusNet appears to have determined 22kV feeder EAR and EUE by applying feeder continuous or 'standard' N ratings. This is a conservative estimate which is acceptable for planning purposes, however in practice the short-term overload capacity (and even the emergency capacity) would be utilised before load shedding feeder circuits. We consider this further as part of assessment of AusNet's sensitivity analyses.

324. Provision is made in the EAR model for embedded generation (i.e. as an offset to the demand), but this feature is not utilised for any of the options considered.

AusNet has undertaken options analysis for remedial action in three sub-regions of the Southeastern Growth Corridor

325. Due to the scale and geographical spread of the forecast demand growth, AusNet has assessed the plans to address the energy at risk in the three supply regions shown in Figure 4.14. One preferred option is proposed per region after studying the following set of at-risk feeders, as follows:[123]

- Pakenham South and Officer – CLN22, CLN23, OFR14, OFR21, PHM21, and PHM22
- Greater Clyde South – CLN11, CLN13 and CRE33, and

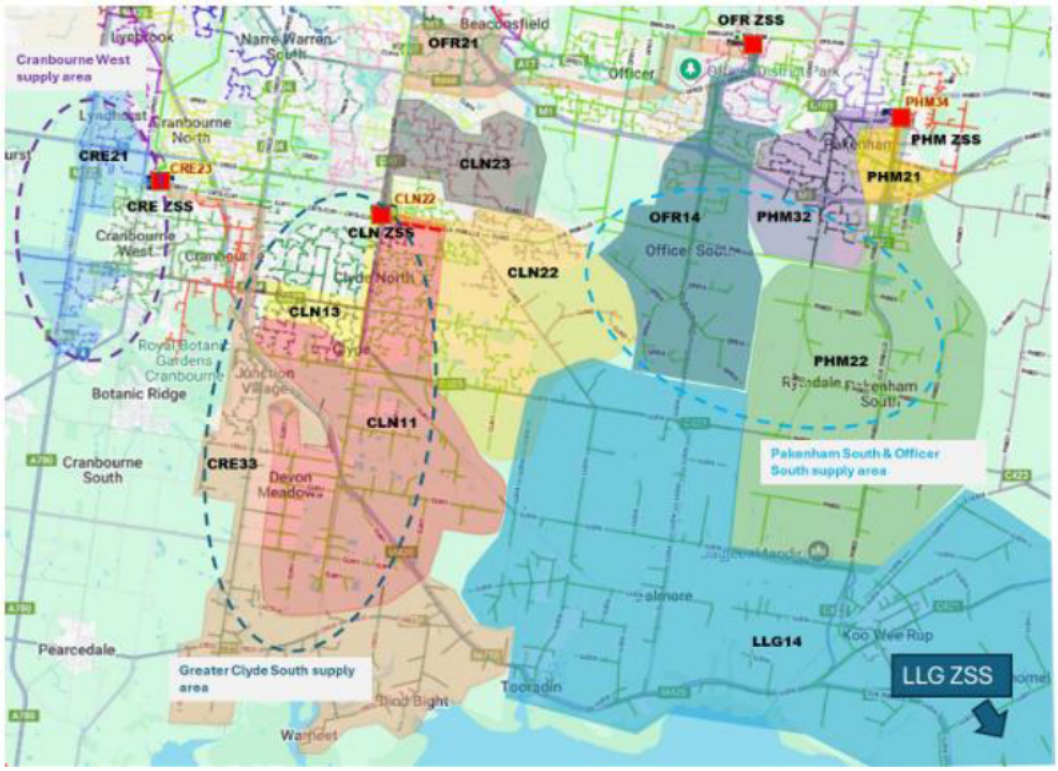
[122] AusNet – Supply security of Southeastern Growth Corridor – 01122025 – CONF. Table 22.

[123] AusNet – Supply security of Southeastern Growth Corridor – 01122025 – CONF. Table 22.

- Cranbourne West – CRE21.

326. AusNet has prepared a development plan and multiple business cases to support the growth corridor. We consider the sub-regional augmentation plans separately at first and then reconsider the program at an integrated, corridor-level.

Figure 4.14: 22kV network supplying the high growth areas within the Southeastern Growth Corridor



Source: AusNet – Supply security of Southeastern Growth Corridor – 01122025 – CONF, Figure 3

Packenham South and Office sub-region augmentation

327. The RP business case included only two options for addressing the overloads in the Pakenham South and Officer sub-region – a second transformer at LLG and the new PHS. The RRP business case considers five options in addition to the 'do nothing' case as summarised in Table 4.16.

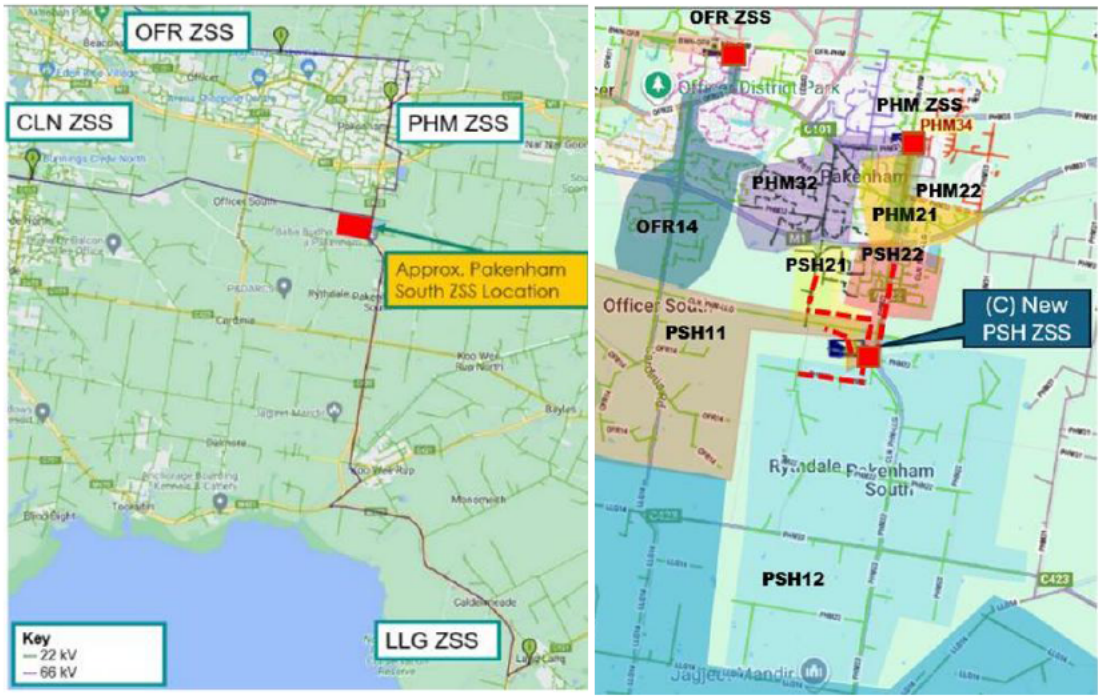
Table 4.16: Southeaster Growth Corridor – Pakenham South and Officer supply area – cost-benefit analysis ($m, real June 2024)

Option	Full assessment period (base case, discounted)		
	Total benefits	Total cost	NPV
Do nothing	0.0	0.0	0.0
Option 1 (preferred): New PHS substation + new distribution feeders	9,984.9	73.6	9,911.3
Option 2: 3rd transformer + bus at PHM + new distribution feeders	8,234.1	44.5	8,189.7
Option 3: 3rd transformer and bus at OFR + new distribution feeders	3,990.4	60.8	3,929.6
Option 4: 2nd transformer and Bus at LLG + new distribution feeders	8,365.7	56.9	8,308.8
Option 5: Contract network services to defer investment	6,375.9	6,375.9	0.0

Source: Supply security of Southeastern Growth Corridor – 01122025 – CONF, Table 2
Costs include capex and opex

328. Option 1 is AusNet's preferred option due to a higher NPV (achieved by mitigating more of the EUE). Figure 4.15 shows the proposed (approximate) location of PHS and feeder coverage for Option 1. We note that as of November 2025, AusNet had not procured the substation site. This may delay the proposed FY27 project start.

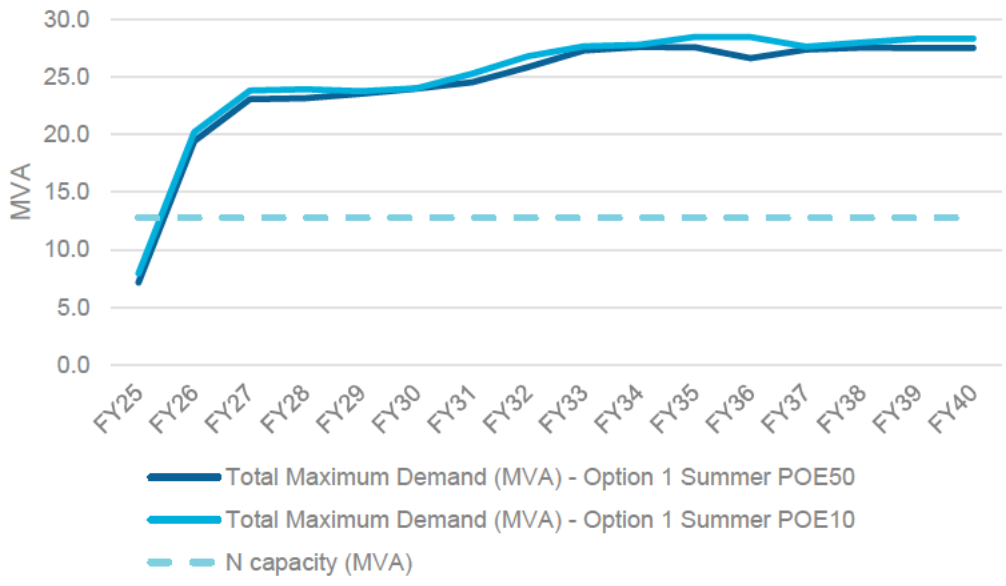
Figure 4.15: Proposed PHS location and feeder supply coverage



Source: Supply security of Southeastern Growth Corridor – 01122025 – CONF, Figures 13, 14

329. By way of example, Figure 4.16 illustrates the steep rise and extent of EAR due to the forecast sharp increase in demand on PHM21 feeder above the N capacity. This is one of the six feeders forecast to be overloaded across the next RCP in the sub-region. The maximum demand is net of the distribution transfer capacity from PHM21.

Figure 4.16: PHM21 – summer demand forecast versus N capacity



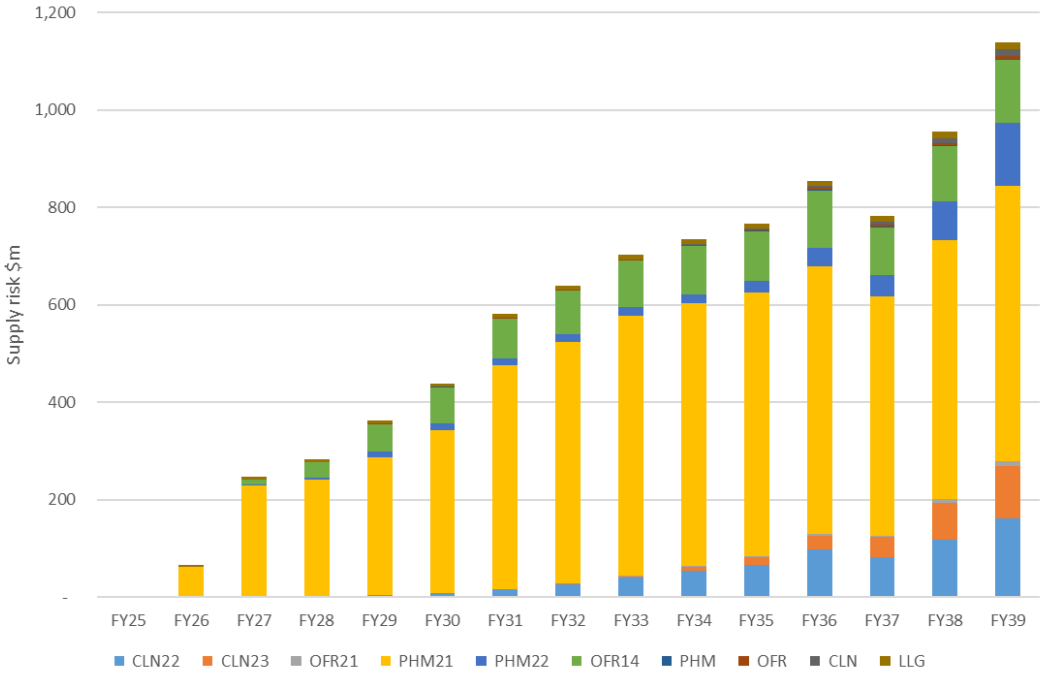
Source: EMCa analysis from E@R PHM21 Feeder V2.7 POE10 – 01122025 – PUBLIC

330. AusNet assumes in its economic model[124] that:

- Incremental energy above the N feeder rating is not supplied to protect feeder integrity - AusNet uses the assumed load duration curve (LDC) to determine when the peak demand is probabilistically likely to be above or below the N capacity and assumes that the corresponding energy is supplied at all times when demand is less than the N feeder rating. This is a simplified representation of what happens in practice when a feeder is overloaded but we consider it is acceptable for planning purposes when the extent of predicted overload is so far in excess of the firm capacity (and in this case, so early in the planning period)
- Incremental energy above the N-1 substation capacity is assumed to be not supplied until the demand is probabilistically determined to return to be less than the N-1 capacity. Again, this is a simplifying assumption that does not reflect operational practice but is acceptable for planning purposes.

331. As shown in Figure 4.17, the contribution to the total EUE for the 'do nothing' counterfactual is dominated by assumed overloading of PHM21 and with OFR14 (from FY28) and CLN22 (from FY32) materially contributing to EUE over time. The contribution of overloading of the ZSSs to the 'do nothing' annual EUE estimate is comparatively minor through to FY39.

Figure 4.17: Pakenham- Officer supply risk ($m) – do nothing scenario and preferred Option 1



Source: Pakenham South Zone Substation Development Project economic model – 01122025 – CONF, 2.2.1 SupplyRisk$ BaseD

332. Option 1 reduces the EUE across the six feeders substantially by enabling load transfer to the new feeders and for them to supply new load. The solution also eliminates the EUE on three of the four substations, also via offloading, with the radially supplied LLG being the exception.

333. Whilst not illustrated, AusNet's model includes the EUE reductions from the other options, each of which provide much less benefit over the medium to long term than creation of PHS (with three feeders initially).

334. We also considered the results of AusNet's sensitivity analysis and we are satisfied that:

[124] AusNet – Packenham South Zone Substation Development Project economic model – 01122025 – CONF.

- Option 1 is the prudent option of those considered; and
- the economic timing is likely to be well within the next RCP, including under AusNet's assumed low demand forecast (90% of base case).

335. As shown in Table 4.15, AusNet proposed building the new PHS substation by FY30 and three of the four proposed feeders in parallel with the substation construction. The feeder and ZSS construction timing is designed to manage overall deliverability challenges.

336. AusNet has provided the cost estimate build-up for Option 1 but it is difficult to identify the sources of increase from the RP estimate. We therefore asked AusNet to explain the sources of increase. AusNet responded with a high level summary and a more detailed response, [125] neither of which reconcile exactly with the $16.1 million difference in cost illustrated between Table 4.14 and Table 4.15:

- In one table in the IR response the cost difference between the RP and RRP for New Pakenham South ZSS is identified as $17.0 million, however it compares costs with different bases and the reasons given for the difference amount to only $8.2 million
- In a second, more detailed table we can identify reasons for $14.4 million of cost difference, but again we do not know if this is comparing estimates on a common base year.

337. Nonetheless, from the more detailed table in the response, it is clear that the key sources of change are as stated by AusNet:

- Scope changes following more design work, including:
  - changes to already identified items such as to feeder cabling, earthworks, 22kV reactor (deleted), and security
  - additional scope such as cultural heritage assessment, battery enclosures, noise walls, sectionalisers, switching cabinets
- Labour, material and installation cost increases.

338. We are satisfied with the detailed explanations of the drivers of cost increase despite the exact reconciliation not being provided. However, for the reasons discussed in Section 3, we consider the cost to be overstated.

Greater Clyde South sub-region augmentation

339. The RP did not include any augmentation in the Greater Clyde South sub-region in its RP. In the RRP, AusNet has studied four options to address the forecast N overloads for feeders CLN11, CLN13, and CRE33 illustrated in Figure 4.12 and which, according to Figure 4.14, supply the Greater Clyde South sub-region.

340. It is not apparent from the relatively modest maximum demand increases from the RP to the RRP for these three feeders (illustrated in Figure 4.14) why consideration of augmentation in the next RCP is now required but was not in the RP. In response to an information request, AusNet states that extending or relying on the RP options to service the emerging growth areas would have required disproportionate additional works, undermining their efficiency and deliverability.[126]

341. We are satisfied with this response and regardless, the forecast overloads on CLN11, CLN13, and CRE33 are individually and collectively significant and therefore the EAR is significant and increasing.

342. The four options and the 'do nothing' case are summarised in Table 4.17 AusNet's preferred solution is to install two new feeders, CLN32 and CLN33 (Option 2) because it has the highest NPV. The proposed solution includes distributing the load on feeders CLN11, CLN13, and CRE33 across five feeders allowing each to be within its asset rating for several years.[127]

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125 IR#069 -Response to EMCa questions 1-9 23012026 – CONF. Pages 2,7-9.

126 IR#079 AusNet Response – 13022026 – CONF. Pages 7-8.

127 EDPR Revised Proposal 2027-31 -Dec2025_PUBLIC, Page 122.

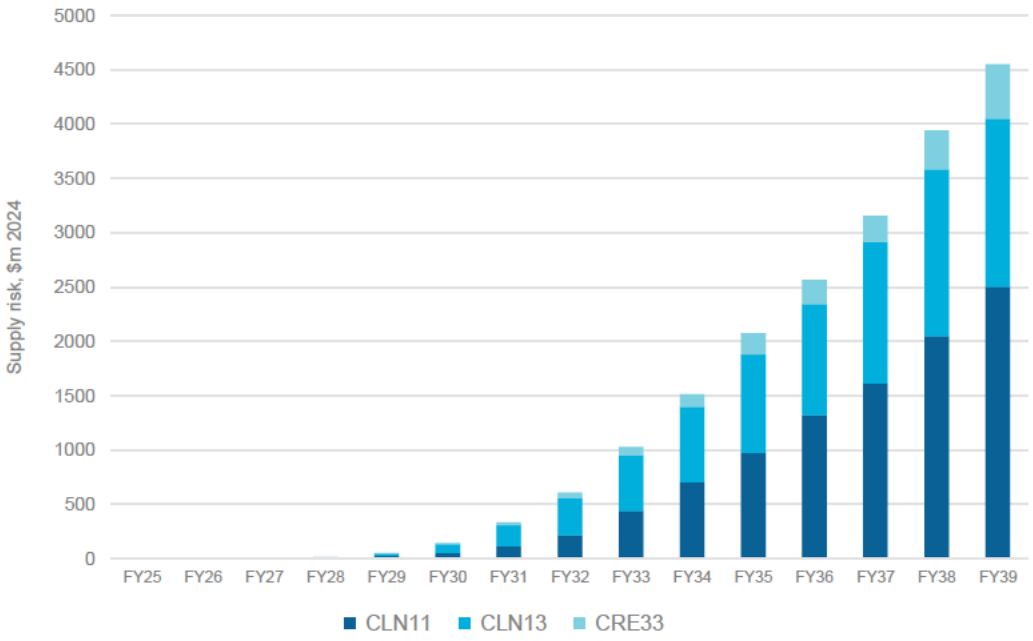
Table 4.17: Southeastern Growth Corridor – Greater Clyde South supply area – CBA ($m, real June 2024)

Option	Full assessment period (base case, discounted)		
	Total benefits	Total cost	NPV
Do nothing	0.0	0.0	0.0
Option 1: Construct a new CLN33 22kV feeder	13,047.4	5.5	13,042
Option 2 (preferred): Construct new CLN32 and CLN33 22kV feeders	22,445.2	24.1	22,421.1
Option 3: Construct three 5MW/10MWh BESS	11,973.6	79.7	11,893.9
Option 4: Contract network services to defer network investment	8,497.6	8,497.6	0.0

Source: Supply security of Southeastern Growth Corridor – 01122025 – CONF, Table 3; Costs include capex and opex

343. Figure 4.18 shows the energy at risk under the 'do nothing' scenario. For the incremental cost of the additional feeder compared to Option 1, the avoided EUE is significant. Whilst Option 1 is much cheaper than Option 2, peak demand would exceed the feeder N ratings again within one year.[128] We are satisfied that of the options presented, Option 2 is the prudent choice.

Figure 4.18: Greater Clyde South supply area – supply risk - do nothing and Option 2 (2 new feeders)



Source: New CLN32 & CLN33 feeders economic model - 01122025 – CONF, 2.2.1 SupplyRisk$ BaseD

344. The economic timing for the preferred Option 2 under the base case assumptions is FY28, and this does not change under the low demand scenario (90% of base case demand) because the annual avoided EUE (i.e. benefit) is so high from FY27 with the peak demand forecast.

345. We asked AusNet to confirm the economic timing of the proposed new feeder CLN32 under base case and low demand scenarios to help confirm that this feeder is prudent to complete

128 New CLN32 & CLN33 feeders economic model - 01122025 – CONF, 2.2.1 SupplyRisk$ BaseD.

in the next RCP. AusNet stated that the economic timing is FY28 under the central case and FY30 under the low demand case.[129]

346. In its response, AusNet also states that it identified errors in the EAR models for CLN11, CLN13 and CRE33 however correcting the errors did not change the preferred option, the economic timing of CLN32 or CLN33, or the material economic benefit of the preferred option.[130]

347. The cost of the two new feeders is $24.3 million in the capex model for the next RCP. We queried the reason for the significantly higher costs for the CLN32 feeder compared to CLN33 and AusNet advised that this is due to the configuration of the feeder and because CLN33 will utilise spare conduits along the route.[131]

CLN 3rd transformer and switchroom

348. AusNet states that the Clyde North ZSS augmentation was included in the final decision for the current RCP.[132] The purpose of the CLN 3rd Tx and switchboard project is to expand the existing CLN ZSS, noting that has already exceeded its N capacity. AusNet states that this project was originally planned for the current RCP but has been delayed, with some costs carried over into the next RCP (as shown in Table 4.15).

349. [redacted]

- Increase for construction and labour costs since estimated in 2021
- An accelerated delivery date of critical components prior to summer 2025 driven by load demand
- Subsequent storage costs for the transformer and switchroom.

350. The drivers of the schedule delay are cited as (in summary) being due to design changes necessitated by, among other things, a Casey Council decision regarding the discharge of stormwater, delaying construction start.

351. All but $7.6 million of the total cost will have been incurred by the start of the next RCP. We note that AusNet states that it updated its economic model with the increased cost and expenditure profile, the latest VCR, and increased risk of asset failure to evaluate the impact on the economic timing for each of the options included in the original business case:[135]

> *'The evaluation has confirmed that it is prudent and efficient to continue with the original preferred option (i.e. the delivery of the full scope of the project) as the optimum timing for project delivery remains unchanged.'*

352. Given the relatively recent update to the cost estimate, we consider the cost estimate to complete the work is likely to be reasonable with the exception of the adjustments we refer to in Section 3.

Cranbourne West supply sub-region augmentation

353. AusNet did not include any augmentation in the Cranbourne West sub-region in its RP. In its RRP, AusNet has studied four options to address the forecast N overload of CRE21 22kV feeder illustrated in Figure 4.12 and which, according to Figure 4.14, supplies the

129 IR#079 AusNet Response – 13022026 – CONF. Page 9.

130 IR#079 AusNet Response – 13022026 – CONF. Page 9.

131 AusNet Direct Cost Summary – Install a new 22kV distribution feeder (CLN22) – 0112205 – CONF and Supply security of Southeastern Growth Corridor – 01122025 – CONF. Page 38.

132 AusNet – DD-0011571 CLN 3rd Transformer and Switchroom PCR02 Signed -06062025 – CONF. Page 1.

133 Inclusive of CFC's, OH's and MR.

134 AusNet – DD-0011571 CLN 3rd Transformer and Switchroom PCR02 Signed -06062025 – CONF. Pages 1-2.

135 AusNet – DD-0011571 CLN 3rd Transformer and Switchroom PCR02 Signed -06062025 – CONF. Page 2.

Cranbourne West sub-region. The forecast overload of CRE21 builds from 0.0MVA in FY28 to 5.6MVA by FY31.[136]

354. The four options and the 'do nothing' case are summarised in Table 4.18. AusNet's preferred solution is to install one new feeder, CRE34, because it has the highest NPV, albeit marginally from Option 2. This is proposed to include distributing the load on existing feeders CRE21 and CRE34, allowing each feeder to be within its asset rating for several years.[137]

Table 4.18: Southeastern Growth Corridor – Cranbourne West supply area – cost-benefit analysis ($m, real June 2024)

Option	Full assessment period (base case, discounted)		
	Total benefits	Total cost	NPV
Do nothing	0.0	0.0	0.0
Option 1: Construct new 22kV feeder CRE34	49.2	8.3	40.9
Option 2 (preferred): Construct a new 22kV feeder via a different route	49.2	9.7	39.5
Option 3: Construct a 5MW/10MWh BESS	42.4	19.1	23.4
Option 4: Contract network services to defer network investment	37.9	37.9	0.0

Source: Supply security of Southeastern Growth Corridor – 01122025 – CONF, Table 4
Costs include capex and opex

355. Figure 4.19 shows the EAR under the 'do nothing' scenario. The other options reduce the EAR to zero (near zero in the case of Option 4).[138] We are satisfied that, of the options presented, Option 1 is the prudent choice as it addresses the overloading issue for the least cost.

356. The economic timing is FY29, that is, as soon as the peak demand is expected to exceed the N rating. Under the low demand case, the economic timing is deferred until FY32.[139]

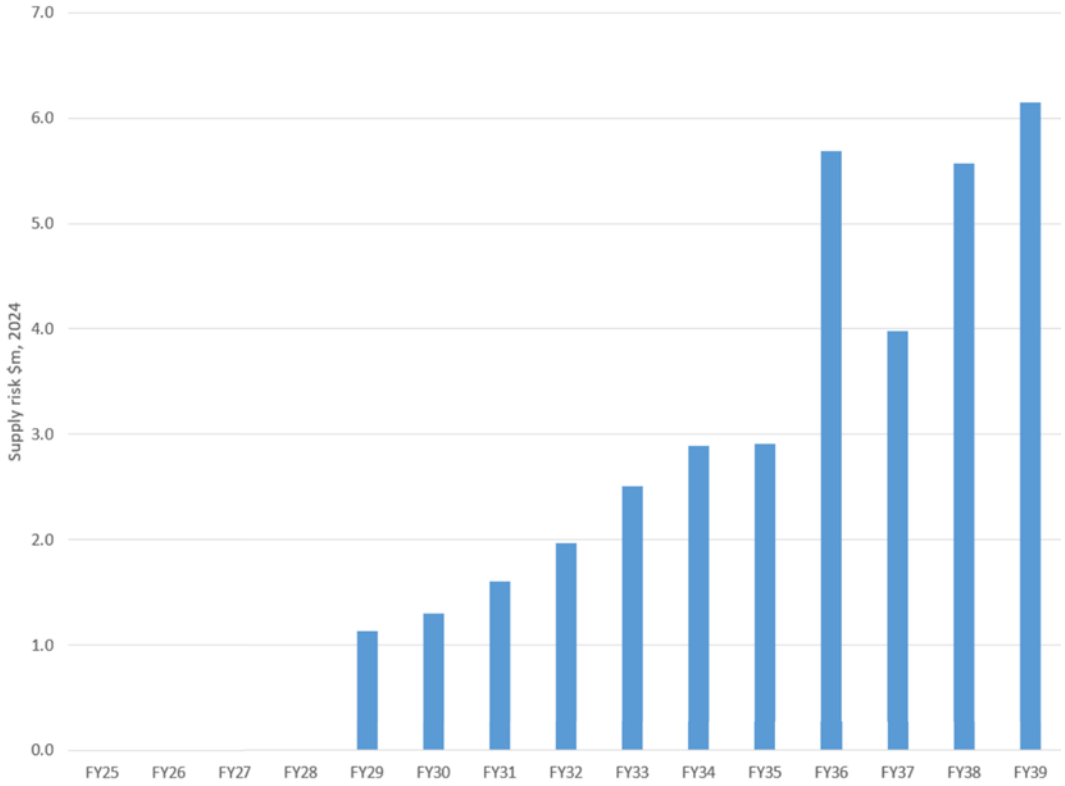
136 Pakenham South Zone Substation Development Project economic model – 01122025 – CONF, 2.2.1 SupplyRisk$ BaseD.

137 EDPR Revised Proposal 2027-31 -Dec2025_PUBLIC. Page 122.

138 Install a new 22kV distribution feeder (CRE34) economic model - 01122025 – CONF, 2.2.1 SupplyRisk$ BaseD.

139 Install a new 22kV distribution feeder (CRE34) economic model - 01122025 – CONF, 3.1 NPV, 3.2.5 NPV (low demand).

Figure 4.19: Cranbourne West Supply area – supply risk - CRE21 under 'do nothing' scenario ($m, 2024)



Source: Install a new 22kV distribution feeder (CRE34) economic model – 01122025 – CONF, 2.2.1 SupplyRisk$ BaseD

357. We have been provided with the direct cost summary and with the exception of the additional allowances discussed in Section 3, we are satisfied with the cost estimates.

CBTS 66kV feeder rearrangement.

358. CBTS 66kV feeder rearrangement project was not included in the RP and therefore was not considered in the AER's draft decision.[140]

359. The project was identified as an enabling component of the preferred option in AusNet Transmission project *Maintaining supply reliability in the Cranbourne supply area* and which is subject to a RIT-T assessment. The PACR was published in late August 2025 and confirmed the preferred option and its optimal timing, being the installation of a fourth 150 MVA 220/66 kV transformer at CBTS at an estimated capital cost of $62.9 million ($2025) by FY27.

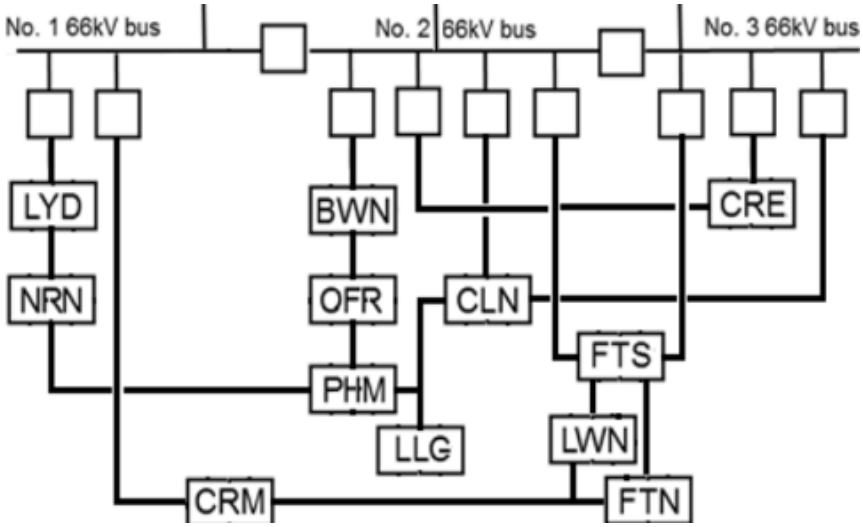
360. The identified need for the RIT-T is to maintain electricity supply reliability and reduce EUE for CBTS customers, delivering market benefits. Electricity demand at CBTS has been amongst the fastest growing in Victoria, and CBTS has reached its full capacity.[141] It is not within our scope to assess the PACR however we do consider the scope of the feeder re-arrangement work, the basis for it, and the cost and timing of the work.

361. Figure 4.20 shows the current 66kV CBTS network schematic, which is supplied via three parallel-operated 150MVA 220/66kV transformers.

140 AusNet – EDPR Revised Proposal 2027-31 -Dec2025PUBLIC. Table 5-29.

141 Cranbourne RIT-T Project Assessment Conclusions Report. Pages 5-7.

Figure 4.20: CBTS sub-transmission network schematic

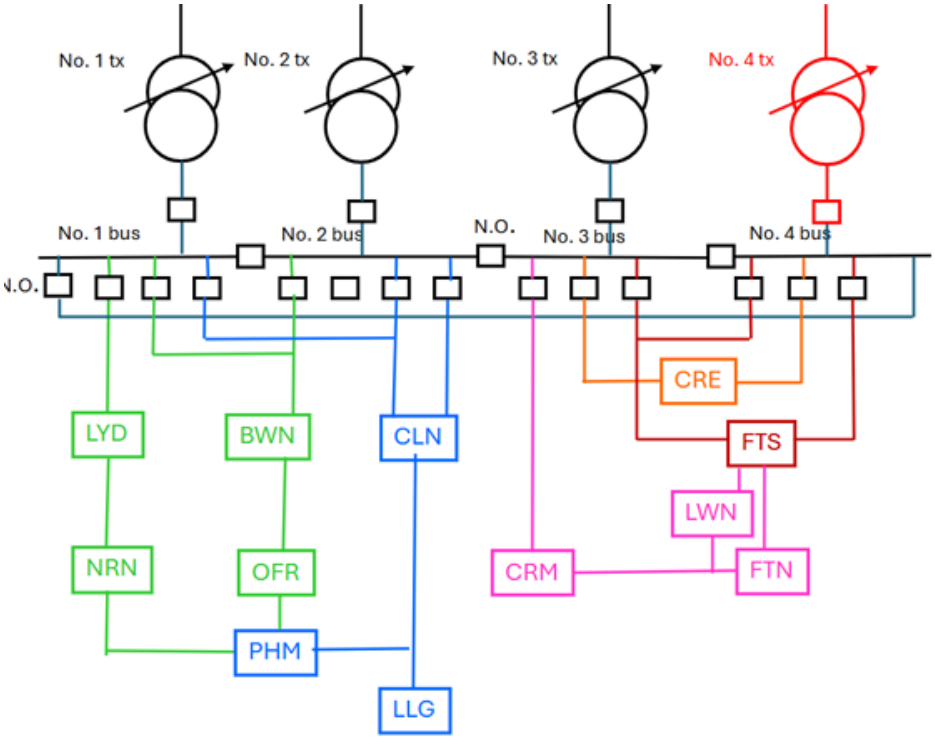


Source: CBTS 66kV Feeder Rearrangement – 01122025 – CONF, Figure 3

362. The scope includes creating 1-2 and 3-4 bus groups and rearranging 66 kV loops/feeders so that there are no loops between the newly created bus groups, as shown in Figure 4.21. The circuit breaker between bus 2 and 3 will be normally open to manage fault levels. The scope also includes replacement of line protection at selected ZSSs to match new line double-switched protection at CBTS.

363. From a technical perspective: (i) running normally open to manage fault levels with four transformers is typical of four-transformer terminal stations, noting that fault levels are manageable with three parallel-operated transformers; and (ii) rearranging the feeder circuits makes sense to enable operation of the two bus groups without looping in the network to manage fault contributions.

Figure 4.21: CBTS proposed transmission connection assets -single line diagram with 66 kV feeder rearrangement



Source: CBTS 66kV Feeder Rearrangement – 01122025 – CONF, Figure 4

364. The estimated cost (±30%) of the feeder re-arrangement component is $6.1 million, with the bulk of the expenditure due to be incurred in FY28 (refer to Table 4.15), which is misaligned with AusNet's declared intent to complete the project in line with the economic timing of FY27 stated in the PACR.

365. Nonetheless, we consider that AusNet's scope and cost estimate are reasonable, with the exception of the additional allowances that it has not sufficiently justified as discussed in Section 3.

Summary of findings

Our initial review accepted the need for Pakenham South ZSS

366. In its RP, AusNet proposed the establishment of PHS and three feeders only and, based on the information before us at the time of our initial review, we considered that building the new ZSS was the prudent solution. However, we found evidence of an over-estimate of the proposed cost.

Updated information supports the proposed PHS and the additional 22kV feeder projects

367. In its RRP, AusNet has not only again proposed establishment of PHS with three feeders but has included a fourth PHS feeder (PHS21) and three other new feeders (CLN32, CLN 33, and CRE34) in the next RCP.

368. The increase in demand that AusNet has assumed for this growth corridor significantly exceeds that included in the RP. The loading of existing feeders necessitates augmentation of the network. We consider that AusNet has taken reasonable steps to mitigate the risk of supply interruptions, however due to the demand growth and network design limitations, augmentation is the prudent solution.

369. From our assessment of the analysis provided with the RRP and by AusNet in response to our information requests, we consider that AusNet's updated analysis has adequately justified the development of PHS and each of the additional feeders. This has led to a materially increased scope of works.

370. In each case we consider that AusNet has selected the prudent option and that the economic timing is likely to be within the next RCP. We note that AusNet has, for deliverability purposes modified the timing of some projects, but again the work is reasonably positioned to be completed within the next RCP with the assumed demand forecast. However, the proposed cost of the PHS and new 22kV feeders is overestimated, for the reasons discussed in Section 3.

The delayed CLN 3rd transformer and switchroom project introduces additional scope and cost into the next RCP

371. AusNet also proposes in the RRP the CLN 3rd transformer and switchroom project, which was not included in the RP. The AER approved the project for commencement in the current RCP; however AusNet has advised that it is running behind schedule and the cost to complete the project will significantly exceed the original estimate, with completion of the work extending into the first year of the next RCP. We consider the cost to be incurred in FY27 as a result of the delay to be reasonable given that it is based on a relatively recent PCR update, with the exception of the sources of cost overestimate that we discuss in Section 3.

The CBTS 66kV feeder arrangement is dependent on a transmission project

372. This project was not included in the RP but is required in the next RCP if the 'parent' transformer project to add a fourth transformer at CBTS proceeds. We consider that the need for the project is sound and that the cost of the rearrangement is reasonably derived with the exception of the sources of cost that are overestimated, as we discuss in Section 3.

4.3.10 Assessment of Northern Growth Corridor Program

Overview of RP and AER's draft decision

373. In its RP, AusNet had included the establishment of a new Wollert ZSS project at a cost of $46.2 million, in response to increasing demand in the region. Specifically, that the 50PoE forecast demand will exceed the N capacity of the Kalkallo ZSS (KLO) that supplies load in the Wollert area by 2027.

374. AusNet proposed the project to be completed over two years by FY28.

375. The AER included $43.1 million for the new Wollert ZSS, after removal of the contingency risk allowance. Table 4.19 summarises the proposed expenditure in AusNet's RP and the AER's response for the project both in terms of the quantum of reduced expenditure and the rationale for doing so. The only issue expressed by the AER was the inclusion of a contingency risk allowance.

Table 4.19: Summary of AER's draft decision for demand-driven augmentation expenditure ($m, FY26)

Projects	Proposal	AER draft decision	Reasons
New Wollert ZSS	46.2	43.1	We consider the proposed investment to be reasonable. Our alternative estimate reflects the removal of the contingency risk allowance.

Source: EMCa derived from AER, Attachment 2 – Capital expenditure | Draft decision – AusNet Services distribution determination 2026-31, table A.2

Overview of RRP

376. As stated earlier in this report, AusNet has revised its augex forecast for the RRP to address updated demand forecasts. AusNet states that the increase in demand forecasts, particularly recent demand peaks, as well as scope changes and cost escalation support the need for a larger program than was initially proposed in the RP.

377. Like the RP, the demand-driven program in the RRP continues to focus on the two growth corridors: Southeastern and Northern. However, the scope of the projects for the Northern Growth Corridor has been expanded beyond the new Wollert ZSS, and the cost estimate for Wollert has also increased. As shown in Table 4.20, AusNet has included six other projects, at a total cost of $243.7 million.

Table 4.20: Demand-driven augex projects – Northern Growth Corridor ($m, June 2026)

Northern Growth Corridor	FY27	FY28	FY29	FY30	FY31	RCP total
Wollert Zone Substation Development Project	15.2	17.8	21.7	-	-	**54.8**
Wollert ZSS 22kV Feeder Augmentation (3 Feeders - WLT12, WLT13 & WLT14)	5.7	18.3	-	-	-	**24.1**
Wollert ZSS 22kV Feeder Augmentation (1 Feeder - WLT21)	-	-	-	3.9	-	**3.9**
Beveridge Zone Substation Development Project	44.1	14.3	-	-	-	**58.4**
Beveridge ZSS 22kV Feeder Augmentation (2 Feeders - BVE11 & BVE12)	19.8	7.5	-	-	-	**27.3**
Beveridge ZSS 22kV Feeder Augmentation (3 Feeders - BVE13, BVE14 & BVE21)	-	10.6	10.7	12.2	-	**33.6**
Augment SMTS-BVE-KMS 66kV Line	1.3	16.7	12.4	11.2	-	**41.7**
Total	**86.1**	**85.4**	**44.9**	**27.3**	**-**	**243.7**

Source: EMCa derived from ASD – AusNet Distribution – SCS Capex Model – 011225 – CONF

Our assessment

Relative to the RP, AusNet has increased its forecast demand for the Northern Growth Corridor

378. AusNet states that the demand forecast has been updated following the hot summer of FY25 (actual demand exceeded the 2024 demand forecast), and new government approvals progressed since the RP for:

- Beveridge North West Precinct Structure Plan (August 2025); and
- Beveridge Interstate Freight Terminal (BIFT) Stage 1 Planning Scheme Amendment (PSA) which enables construction to begin (August 2025).

379. The Northern Growth Corridor is supplied, in part, by AusNet's existing zone substations: KLO, Doreen (DRN), and Epping (EPG), through a network of 22 kV distribution feeders. These areas are experiencing rapid growth:[142]

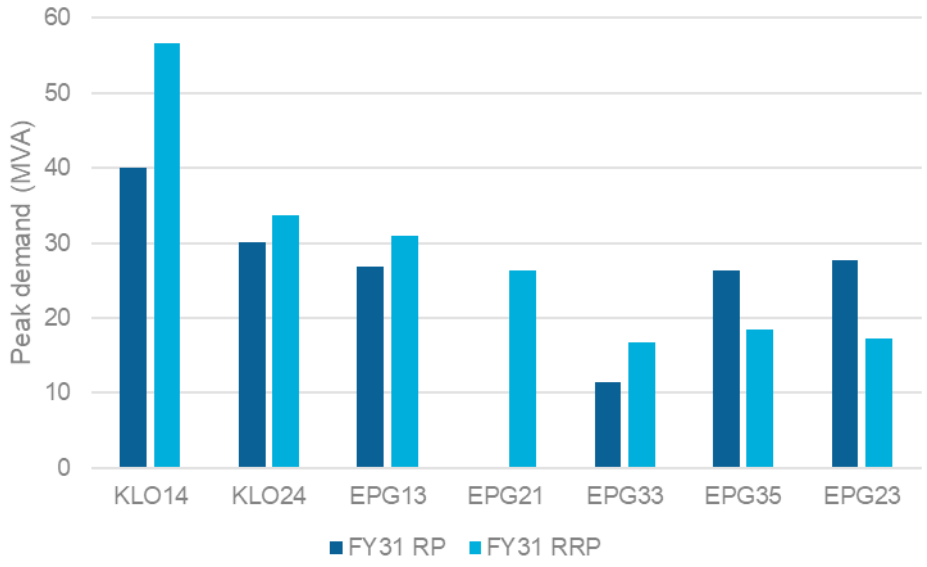
> *'Of particular concern is the projected load growth on several 22 kV distribution feeders—KLO14, KLO24, EPG13, EPG21, EPG33, EPG35, and EPG23—which serves the communities of Beveridge, Wollert, Wallan, and parts of Wandong and Whittlesea, as well as surrounding areas.'*

380. To illustrate the change in demand forecast, we have reproduced the demand forecast for the feeders that AusNet has identified to be of particular concern in Figure 4.22. We show the estimated demand at the end of the next RCP (FY31).

381. As shown in Figure 4.22, the summer peak demand forecast has increased significantly since the RP, particularly for the KLO24 feeder. Individually and collectively, these overload predictions point to significant existing and growing energy at risk, when compared with a feeder rating of 14.5MVA notwithstanding some of the difference will be met by available transformers and demand management is not included here.

[142] ASD – AusNet - Supply security of Northern Growth Corridor - 01122025 – CONF. Page 3.

Figure 4.22: RP versus RRP FY31 PoE10 peak demand forecasts (exc. available transfers – Summer) for relevant Northern Growth Corridor 22kV feeders



Source: EMCa derived from Supply security of Northern Growth Corridor, Table 35
Note: EPG21 was not included in the RP

382. Whilst not explicitly shown above, the overloading is present from FY25, with the PoE10 summer demand forecast of 22.2 MVA exceeding the feeder rating of 14.5 MVA by 7.7 MVA. At around FY28, the feeder switches from a summer peaking load to a winter peaking load. Also, the rate of change is significant, with the winter PoE10 demand almost doubling every 2-3 years, indicating to us a very high demand growth in the area serviced by this feeder network

Some network elements are already overloaded

383. AusNet states that feeders KLO14, KLO24 and EPG13 are already operating above their design ratings, and despite investments in demand response and local diesel generation, customers on these feeders have experienced interruptions due to load shedding events.

384. AusNet also projects overloads for other feeders in the next RCP, and has commenced construction of a further 12MW of generation at a site in Wallan:[143]

> *'To manage network demand, we deployed targeted generation during summer 2024/25, including 3.95 MW at the Wallan Sewer Plant (YVW), multiple units at Freeway Enterprise totalling 2.62 MW, and additional capacity at Beveridge (0.9 MW) and Hidden Valley (2.2 MW). These deployments were not without challenges, particularly in finding suitable sites and managing the significant costs of security following repeated copper theft incidents last summer. Despite these efforts, load shedding was required to protect equipment from damage and maintain overall system stability, highlighting the scale of demand pressures. Looking ahead to summer 2025/26, a 12 MW generation site is under construction at Wallan (split evenly between KLO14 and KLO24), complemented by 1.1 MW on EPG feeders. Critical feeders such as KLO14, KLO24, and EPG13 are also being operated at emergency ratings for short durations to provide additional resilience. While these measures have helped mitigate risks in the interim, challenges remain until a permanent solution is in place. This level of network risk is forecast to grow until our proposed network upgrade projects are in service and will be managed during this period using the measures outlined in the above section.'*

385. In addition to the feeder constraints, AusNet states that there are no spare feeder circuit breakers to connect new feeders or augment existing feeders. AusNet estimates the

143 ASD – AusNet - Supply security of Northern Growth Corridor - 01122025 - CONF. Page 4.

current level of N overloading is 13.3MVA in FY26 and which it projects to increase to 118.4 MVA by FY32.

386. We are satisfied that it is prudent for AusNet to consider remedial action to mitigate the risk of further load shedding and constraints on new customer connections in the Northern Growth Corridor, based on its demand forecast.

We observe some inconsistencies in the demand forecast information provided

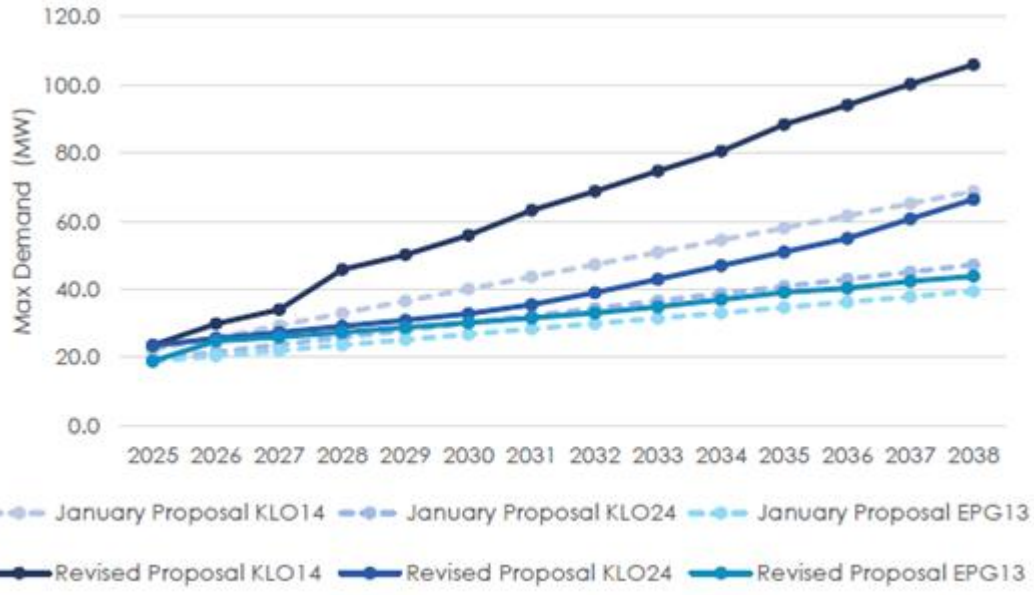
387. We found demand forecast information published in AusNet's business case, also in its corridor plan and its economic models. We found instances where these values did not align. For the purposes of our review, we have assumed that the demand forecast relied upon for the economic modelling (and which was provided in separate excel models) was the most accurate. We observed that this accounted for load transfer, local generation and demand management, and which may explain some of the issues we observed.

388. In response to our request for information, AusNet also confirmed that the economic modelling is accurate, and that the PoE50 demand forecast tables included in the business cases had been transcribed incorrectly.

389. For our assessment, subject to economic modelling, we consider that the PoE10 demand forecast is a reasonable limit for N conditions for considering augmentation options and PoE50 for N-1 conditions, consistent with contemporary planning practices.

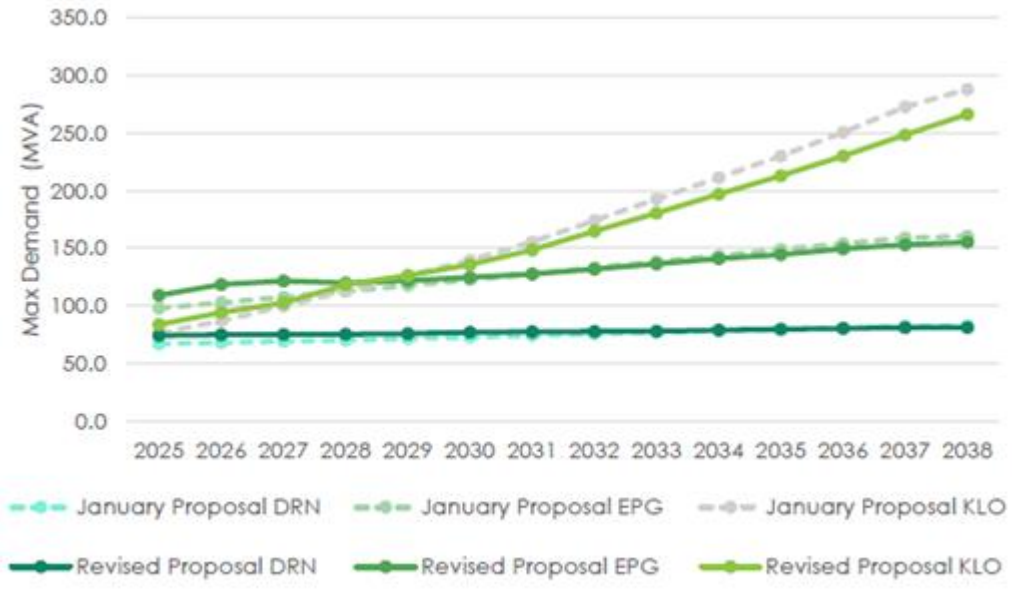
390. We also observe that despite what appear to be material increases in demand at the feeder level (as shown in Figure 4.22) there was not a commensurate increase in demand at the substation level. This is best illustrated in Figure 4.23 and Figure 4.24, shared with us during our onsite discussion with AusNet.

Figure 4.23: Forecast demand initial vs. revised proposal – KLO14 and KLO24 feeders (summer PoE10)



Source: EMCa workshop slides - Augex 29012026 - CONF

Figure 4.24: Forecast demand initial vs. revised proposal – KLO and EPG substation (summer PoE10)



Source: EMCa workshop slides - Augex 29012026 - CONF

391. During our onsite discussion, AusNet stated that the difference observed between the feeder and substation level was due to the different approaches to modelling of diversity at the substation and feeder level, responding to the draft decision. The change in modelling of block loads is cited as contributing to the year 1 overloads as explained in Section 3.2.2. The review of the demand forecast and demand forecasting methodology is not within our scope, however we bring to AER's attention the magnitude of these differences and their implications.

392. For the purposes of our assessment, we have tested the sensitivity of the proposed expenditure to variations in demand.

AusNet has prepared a development plan and multiple business cases to support the growth corridor

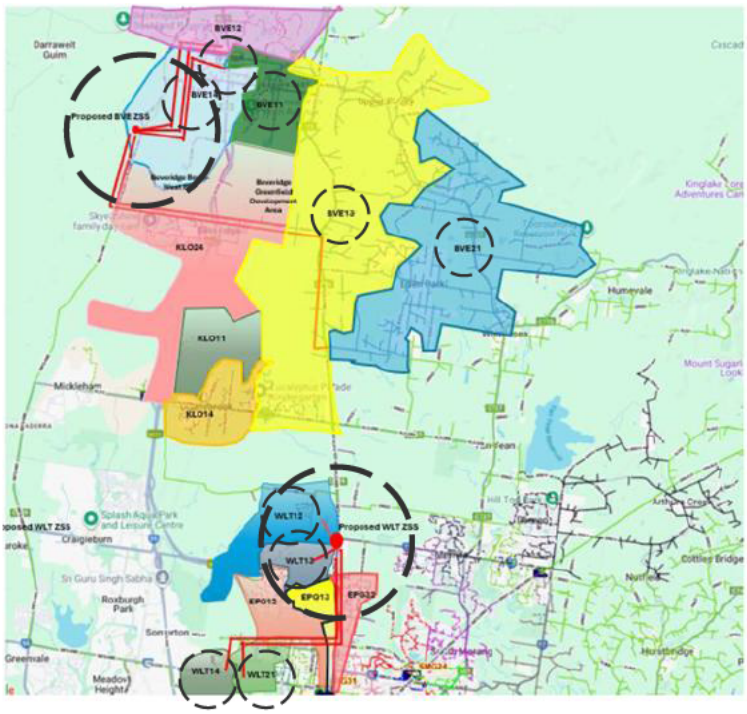
393. In response to the increasing demand in the region, AusNet has prepared a development plan for the Northern Growth Corridor and included this with its RRP. The scope of the development plan includes EPG and KLO substations, associated with the two distinct growth areas of Wollert and Beveridge. The plan extends to the areas supplied by Doreen (DRN) and Kilmore South (KMS) substations.

394. AusNet has provided a business case, economic model and assessment of energy at risk for new substations at Wollert (WLT) and Beveridge (BVE), in addition to proposed sub-transmission and distribution feeder developments with a study period through to 2045.

395. AusNet refers to the VPA North Growth Corridor Plan (2012) and two VPA tools being Precinct Structure Plans (PSPs), and Infrastructure and Development Staging Pan (IDSP), which indicate the staging of greenfield growth across the corridor as input for its growth assumptions.

396. Whilst the development plan also includes location of subsequent substations and reinforcements, we show the approximate location of the BVE and WLT substations and targeted feeders proposed for the next RCP in Figure 4.25.

Figure 4.25: Proposed new substations and distribution feeders



Supply security of norther growth corridor, Figure 12: Proposed 22kV distribution feeder works

397. We observe that BVE and WLT are in close proximity to the sub-transmission network and allow connection to the distribution loads and growth areas of Beveridge and Wollert as discussed earlier.

AusNet has considered a reasonable range of options, and which has been expanded since the RP

398. In its revised business case, AusNet has explored a number of options as shown in Table 4.21 with its preferred option (Option 1) to establish the Beveridge and Wollert new ZSSs, and a sub-transmission upgrade to Beveridge with associated distribution feeders. Option 1 has the most significant economic benefit, associated with the new developments included in the demand forecast.

Table 4.21: Summary of economic analysis – Northern Growth Corridor ($m, real June 2024)

Option	PV costs	PV benefits	NPV
Option 1: (**preferred**) Beveridge and Wollert new zone substations, and a sub-transmission upgrade to Beveridge	248.9	217,352.6	217,103.7
Option 2: Third transformer and bus at Doreen zone substation with new distribution feeders to Wollert, plus Beveridge new zone substation, and a sub-transmission upgrade to Beveridge	316.8	199,850.5	199,533.7
Option 3: Third transformer and bus at Kalkallo zone substation with new distribution feeders to Beveridge, plus Wollert new zone substation, and a sub-transmission upgrade to Wollert	364.6	193,232.6	192,868.0
Option 4: Third transformer and bus at Kalkallo zone substation with new distribution feeders to Beveridge, plus third transformer and bus at Doreen zone substation with new distribution feeders to Wollert	371.1	166,847.9	166,476.8
Option 5: Contract network support services to defer network investment	56,537.0	56,537.0	0

Source: Supply security of northern corridor business case, Table 30

399. Based on the updated assessment, Option 1 is the prudent option to progress.

400. We observe that these options differ slightly from a wider range of options included in our onsite discussion with AusNet, and which included the original Wollert substation option included in the RP.

401. We asked AusNet to compare the preferred solution with the originally preferred option, to understand the sources of change in the 12-month period since the RP. We summarise the response as follows:[144]

- Updated demand analysis identified distinct and concentrated load growth in the Beveridge and Epping/Wollert areas, located approximately 20 km apart within the Northern Growth Corridor
- The project scope has matured to address deliverability and constructability constraints that were not fully defined in the RP:
  - the scope developed for the RP was functional and relied on several assumptions that ultimately proved inconsistent with the requirements of the Northern Growth Corridor once more detailed design was undertaken
  - assumptions that the Wollert ZSS only option that: (i) mostly overhead solutions (by upgrading existing overhead assets along arterial roadways) would be deployed; and (ii) KLO14/KLO24 would be offloaded before the Remote REFCLs to avoid the need for additional REFCL augmentation, are no longer valid
  - updated forecasting and modelling demonstrated stronger load growth in the satellite Beveridge area, requiring either significantly longer feeders from Wollert incorporating REFCL protection or, alternatively, supply from KLO, which in turn would trigger REFCL upgrades at KLO due to increases in network capacitance not included in the RP
- In both cases, materially more underground cable was required than initially assumed due to Department of Transport and Planning (DTP) requirements for new assets along the arterial roadways to be undergrounded. On this basis, the new BVE ZSS is proposed instead of supplying the Beveridge load centre from WLT or KLO, as assumed in the RP. As a result, the establishment of BVE in addition to WLT emerged as the least cost, technically feasible option, and

[144] AusNet response to information request IR079.

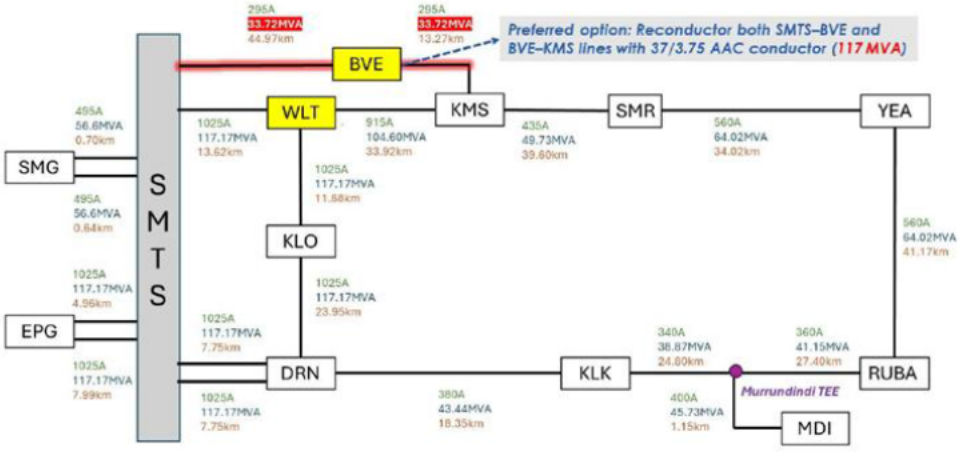
- Further detailed network analysis undertaken during preparation of the RRP identified the need for additional sub transmission reinforcement to reliably supply the Beveridge load centre from the proposed BVE ZSS.

402. In addition to consideration of the Northern Growth Corridor projects as a package, AusNet also considered the benefits and economic timing for the BVE substation and feeders, WLT substation and feeders and the sub-transmission augmentation.

An upgrade to the sub-transmission network is also indicated from the demand forecast

403. Based on the demand forecast, the N-1 rating of SMTS–BVE is exceeded in 2027 after the addition of BVE. However, the N rating is not exceeded until 2032. The network configuration is shown in Figure 4.26.

Figure 4.26: Proposed sub-transmission augmentation



Source: Supply security of Northern Growth Corridor business case, Figure 14

404. In addition to the do-nothing option, AusNet considered a range of options for upgrading the 66kV line, as shown in Table 4.22.

Table 4.22: Summary of economic analysis – norther growth corridor, sub-transmission augmentation ($m, real June 2024)

Option	PV costs	PV benefits	NPV
Option 1. Upgrade only the SMTS-BVE section to 117MVA (37/3.75 AAC conductor), leaving the BVE-KMS section at 33.7 MVA	31.9	18,754.1	18,722.2
Option 2. Upgrade only the SMTS-BVE section to 104MVA (19/4.74 AAC conductor), leaving the BVE-KMS section at 33.7 MVA	15.5	17,425.7	17,410.2
Option 3 (preferred). Upgrade both the SMTS-BVE and BVE-KMS section to 117MVA (37/3.75 AAC conductor)	43.1	18,786.9	18,746.2
Option 4. Building the new BVE–BVE Tee line (tee-out from the WLT–KMS line)	9.3	11,503.9	11,494.7
Option 5. Combination of Option 1 and Option 4. Upgrade the SMTS–BVE section to 117MVA, leaving the BVE–KMS section at 33.7 MVA.	41.5	16,439.8	16,439.8

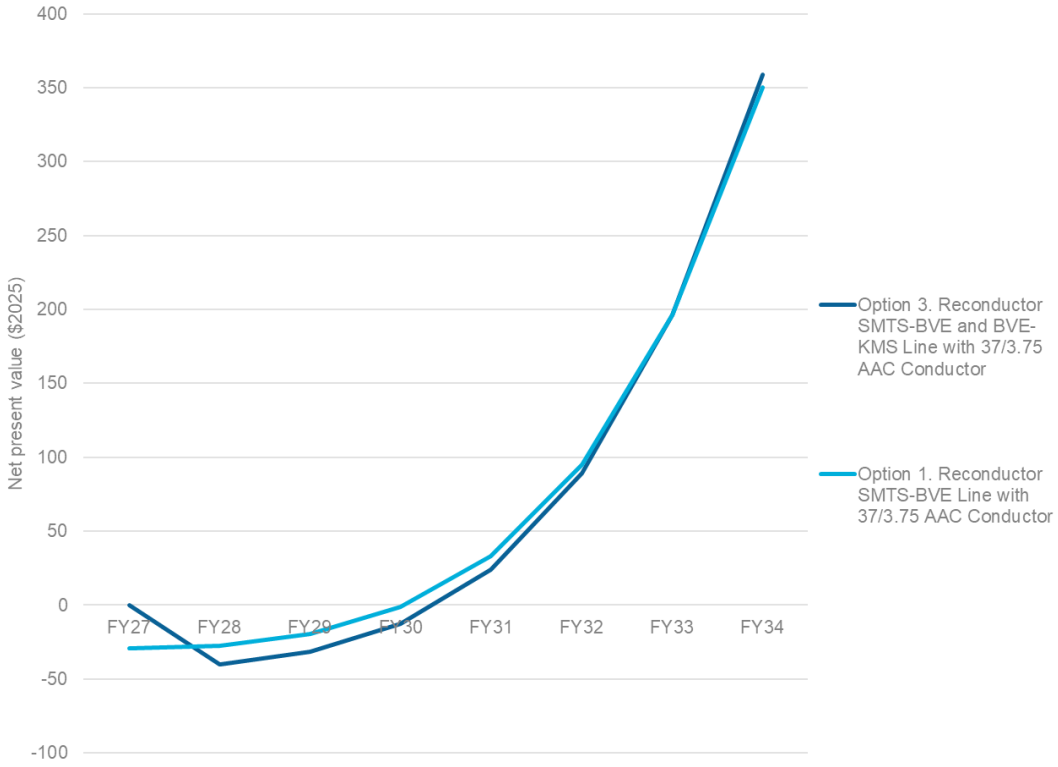
Source: Supply security of northern corridor business case, Table 22

405. AusNet determines that Option 3 is preferred as it is the only option to reduce the EUE under N-1 contingency conditions. Options 1 and 2 provided comparable benefits at a lower capital cost.

406. We therefore considered whether a lower cost option would be preferable. As shown in Figure 4.27, Option 1, due to its similar benefits and lower cost has a higher NPV until FY34, after which time the NPV of AusNet's preferred Option 3 is the higher of the two. We understand that from AusNet's modelling, if an N-1 contingency occurs on the SMTS–BVE line, the BVE–KMS line will become heavily overloaded under these options, and which is not upgraded under Option 1.

407. Based on selecting the option with the highest NPV, Option 3 is the prudent option. This is also supported by our reading of AusNet's planning standard,[145] which indicates that 37/3.75 AAC conductor (117MVA rating) is the AusNet standard for urban 66kV lines.

Figure 4.27: Comparison of NPV of Option 1 and Option 3 ($real 2025)



Source: EMCa analysis of ASD - AusNet - Augment SMTS-BVE-KMS 66kV Line Upgrade economic model - 01122025 - CONF (based on option 2 and Option 4 in the model, which align with option 1 and option 3 in the business case)

Based on the demand forecast, the assessment of EUE is reasonable

408. AusNet assumes in its economic model that:

- At the feeder level, demand above the N feeder rating is not supplied, due to load shedding. AusNet uses the assumed LDC to determine when the peak demand is probabilistically likely to be above or below the N capacity and assumes that the corresponding energy is supplied at all times when demand is less than the N feeder rating. This is a simplified representation of what happens in practice when a feeder is overloaded but we consider it is acceptable for planning purposes when the extent of predicted overload is so far in excess of the firm capacity (and in this case, so early in the planning period)
- At the substation level, demand above the N-1 substation capacity is not supplied until the demand is probabilistically determined to be less than the N-1 capacity. Again, this is a simplifying assumption that does not reflect operational practice but is acceptable for planning purposes.

409. As stated above, the growth in demand forecast, taken together with the existing level of overloading of the feeder network, is driving the calculation of energy at risk, and value of

145 ASD - AusNet - Distribution Network Planning Standards and Guidelines_AMS 20-16 - 01122025 – CONF. Page 28.

expected unserved energy. The very high values are directly related to the assumed growth in demand.

Modelling for economic timing is not correct

410. As discussed in Section 3, AusNet incorrectly derives the annualised cost of its preferred Option 1 as $13.3 million capex from the discounted capex rather than the undiscounted cost leading to an understatement of the annualised cost by $1.5 million. However given the scale of benefits associated with the demand growth, this does not affect the economic timing for any of the options.

Sensitivity analysis supports selection of 66kV line upgrade Option 1

411. Sub-transmission line upgrade Option 1 was superior to the other options in Table 4.22 and the do nothing counterfactual under all sensitivity analyses. Due to the forecast demand growth, this conclusion is not expected to change for the low demand case.

412. The optimal timing is FY28 and when separated for each of the three projects, the optimal timing is between FY28 and FY29, all of which are within the next RCP.

Capex smoothing has resulted in deferral of WLT ZSS and initial feeders

413. As stated in Section 3, AusNet has deferred delivery of WLT ZSS by one year from its economic timing due to capital smoothing. There is no change proposed for BVE substation.

414. In its RRP, AusNet states that temporary measures will be deployed to support the immediate supply risk and allow for capex smoothing to be undertaken:[146]

> *'To support these projects and timing, we have temporary measures in place to support supply risk over the next 2-3 years while construction is underway. These are temporary measures that can support low levels of energy at risk but cannot provide a cost-effective permanent solution.'*

415. We also reviewed whether AusNet has adequately considered the staging of works in the area. Due to the demand growth, the need for establishment of BVE and WLT and the initial set of feeders early in the next RCP is reasonable. This also assumes the cut-in works for the connection to the sub-transmission network, and which is separate to the planned sub-transmission augmentation project which is scheduled for completion by FY30. Whilst we did not find reference to the project schedule, we would expect that the SMTS–BVE upgrade would be prioritised to address the constraint.

416. For the feeder works, AusNet has determined the demand growth related to each substation load area and determined based on the feeder rating when new feeders would be required. This represents a coarse approximation of the staging of feeders, as it does not take account of network topology, load transfers, or distributed generation. However, for the purposes of determining the ultimate planning requirements for regulatory allowance purposes, it is a reasonable approximation.

417. Based on the demand forecast, a total of four feeders at WLT and five feeders at BVE by FY30 are required. Given the method applied by AusNet shown in Table 4.23, if the demand forecast was not realised, a proportion of the feeder works could be reasonably deferred.

418. In the same response, AusNet states that the initial feeder staging (as reproduced in Table 4.23) was refined through the capex smoothing process to require the feeders to be constructed later, and which led to the deferral of WLT (including the initial two feeders).

146 AusNet – EDPR Revised Proposal 2027-31. Page 70.

Table 4.23: Wollert required number and staging of feeders to address forecast overload

	Asset	FY27	FY28	FY29	FY30	FY31
Forecast Overload (POE10)	EPG13	10.2	11.5	12.8	14.2	15.6
	EPG21	1.6	6.3	9.9	13.3	16.7
	EPG33	1.7	3.2	4.7	6.2	7.6
	EPG35	3.1	3.9	5.3	6.5	7.7
	EPG23	0.0	2.0	2.9	4.5	6.2
	Total overload	**16.6**	**26.9**	**35.6**	**44.7**	**53.8**
Required No. of Feeders (POE10)		**2**	**2**	**3**	**4**	**4**
Capacity created by new feeders		**29**	**29**	**43.5**	**58**	**58**
Forecast Overload (POE50)	EPG13	7.8	9.0	10.1	11.4	12.7
	EPG21	0.0	2.3	5.4	8.5	11.6
	EPG33	0.0	0.0	1.5	2.9	4.2
	EPG35	2.2	2.9	4.1	5.3	6.6
	EPG23	0.0	0.8	1.6	2.9	4.5
	Total overload	**10**	**15**	**22.7**	**31**	**39.6**
Required No. of Feeders (POE50)		**1**	**2**	**2**	**3**	**3**
Capacity created by new feeders		**14.5**	**29**	**29**	**43.5**	**43.5**

Source: AusNet response to IR#079, Table 4-1

The estimated cost has increased significantly

419. In Table 4.24 we show the grouping of projects by AusNet to assist with understanding the driver of the significant increase in proposed augex from the RP. The expanded scope is primarily driven by the higher forecast demand growth.

Table 4.24: Northern Growth Corridor project grouping - including overheads ($m, real June 2026)

Northern Growth Corridor	RP	AER draft decision	RRP	Rationale for revised proposal
New Wollert ZSS	50	45.5	88.4	Includes ZSS $58.5 million plus feeders $29.9 million due to increase in demand forecast on feeders and increase in cost above RP.
New Beveridge ZSS	n/a	n/a	127.7	Includes ZSS $62.6 million plus feeders $65.1 million due to increase in demand forecast on feeders
SMTS-BVE-KMS 66kV	n/a	n/a	44.5	Triggered by the new Beveridge ZSS
Total	**50**	**45.5**	**260.7**	

Source: EMCa derived from RRP, Table 5-27

420. In its RP, AusNet only included a project to build the new WLT at a cost of $45.5 million, and which has increased to $54.8 million in the RRP. We have been provided with updated cost estimates for all components of the project. We make the following observations for the substation costs:

- The substation cost estimates are based on a detailed cost build-up, that AusNet states is based on Beveridge and applied to other sites including Wollert

- AusNet has updated costs associated with civil and construction based on more recent completed work
- AusNet includes costs for scope items which were not factored into the costs included for the RP, such as REFCLs at Beveridge.

421. For the distribution feeder costs:

- AusNet's engagement with local planning authorities has identified constraints in constructing further overhead lines heading north from Wollert and Beveridge substation, requiring a higher cost underground cable option
- AusNet has identified longer feeder routes than initially assumed, to offload existing feeders and accommodate forecast growth.

422. We consider that the scope assumptions that AusNet has relied upon are reasonably formed.

AusNet provides an explanation of differences in its assumed cost estimate

423. In its RRP, AusNet states that the direct cost component included in the SCS capex model differed to the updated cost estimates provided for two projects, the Beveridge ZSS and SMTS–BVE–KMS 66kV augmentation. AusNet states that this is due to changes to the cost estimate following preparation of the capex forecast for the RRP, and which means that the sum of the cost estimates is higher than included in the capex forecast by $1.5 million.[147]

424. AusNet states that these changes do not impact the economic timing and preferred option of the business case, and we agree as they fall within the sensitivity boundaries tested in the model.

425. In general, we consider that the forecast prepared at the time of the RRP is based on the best knowledge available at the time, cost estimates that fall within accuracy tolerances determined by the scope maturity and reflect an equal probability of being over- or under-estimated.

426. We saw evidence of cost movements of a similar magnitude as shown in Table 4.25.

Table 4.25: Comparison of cost estimates

Project	Detailed cost estimate (Direct cost + P50 risk)	Business case (Direct cost + P50 risk)	SCS capex model (Direct cost unescalated excluding TOMSA)	
	$2025	$2025	$2024	$2025[148]
Beveridge ZSS	50.1[149]	53.8	[redacted]	[redacted]
SMTS-BVE-KMS 66kV augmentation	34.6	37.0	[redacted]	[redacted]
Wollert ZSS	n/a	50.1	[redacted]	[redacted]
Wollert ZSS + 4 feeders	75.5	75.5	[redacted]	[redacted]

Source: EMCa derived from Northern Growth Corridor business case, project cost estimates and SCS capex model

427. We consider that the capex model values align with the values included in the business case, after adjusting for inflation and any differences to the cost estimate are immaterial in the context of the total cost of $243.7 million proposed for this project.

147 For BVE substation the capex forecast is $3.5 million lower than the updated cost estimate, and for the 66kV line the capex forecast is $2 million higher than the updated cost estimate.

148 Escalated from $2024 based on factors in AusNet's SCS capex model. There may be small differences due to rounding.

149 A P50 risk allowance was not included in the cost estimate, and if included will increase the cost further. The direct cost excluding the P50 risk allowance in the cost estimate was $0.7 lower than in the business case.

Summary of findings

Our initial review accepted the need for Wollert ZSS

428. In its RP AusNet proposed the establishment of Wollert ZSS only and based on the information before us at the time of our initial review, we considered that building the proposed new Wollert ZSS was the prudent solution. However, we found evidence of an over-estimate of the proposed cost.

Updated information supports commencement of the proposed projects

429. From our assessment of the RRP, we consider that AusNet's updated analysis has reasonably responded to the concerns expressed in our initial review and the AER's draft decision and which leads to the development of an alternate solution requiring the establishment of two substations, at Wollert and Beveridge and sub-transmission augmentation at Beveridge. Also, for the alternate solution, the associated feeder networks are of a different design and require larger sections of underground cable construction than initially assumed. The combination of these factors has led to a materially increased scope of works.

Proposed cost is overestimated, for the reasons discussed in Section 3

430. We consider that AusNet's updated cost estimate for the increase in scope is reasonable, with the exception of the combination of allowances that it has not sufficiently justified as discussed in Section 3.

Later project staging remains sensitive to the demand assumptions

431. The increase in demand that AusNet has assumed for this growth corridor, significantly exceeds that included in the draft decision. We have observed some level of inconsistency in the information provided to us. However, the loading of existing feeders necessitates augmentation of the network. We consider that AusNet has taken reasonable steps to mitigate the risk of supply interruptions, however due to the demand growth and network design limitations, augmentation is the prudent solution.

4.3.11 Summary of findings

AusNet has reasonably justified the summer and winter network readiness program

432. We are satisfied that AusNet's capex forecasting approach based on average historical expenditure provides a reasonable estimate for the next RCP.

For the WGL feeder and switchboard project, a lower cost solution is available

433. With the assumed demand forecast and adjusting for more reasonable cost estimates for the two BESS installations and, subsequently, the replacement battery for the original BESS, the proposed Option 3 BESS approach presents a higher NPV than AusNet's preferred Option 1. The optimal timing for installing the first BESS is within the next RCP.

For the balance of projects we consider that the solutions are prudent, however the revised costs are higher than an efficient cost

434. From our assessment of the RRP, we consider that AusNet's updated analysis has reasonably responded to the concerns expressed in our initial review and the AER's draft decision. Accordingly, we consider that, based on the assumed demand forecast, the projects are prudent to include in the next RCP.

435. We consider that AusNet's updated cost estimates for the increases in scope are reasonable. However, AusNet's proposed expenditure includes a combination of allowances that it has not sufficiently justified, as discussed in Section 3.

Projects are sensitive to the assumed demand growth

436. The timing of capex, particularly in the later years of the next RCP, is sensitive to the assumed demand forecast. Whilst the increase in demand that AusNet has assumed indicates that the projects should proceed, the extent of the demand growth impacts the prudent timing of the proposed capex, with a particularly focus on the end of the next RCP.

437. The ability to reprioritise works that are otherwise targeted at addressing network overloads casts a level of doubt on the robustness of the demand forecast. Nonetheless the extent of demand growth requires commencement of this program, and the extent to which the demand growth is realised may defer the feeder projects to an extent.

4.3.12 Alternate estimate

Over-estimation of included projects

It is reasonable to allow for some cost increases; however, we consider that the revised costs are upwardly biased

438. AusNet has developed revised costs estimates for inclusion in its RRP, and we consider that the combination of cost allowances results in an over-estimate of the efficient cost as described in Section 3.2.4. We have estimated the impact of the issues that we have identified as being approximately 11%, comprising:

- approximately 5% of the total capex, based on the weighted average P50 risk allowance that has been included by AusNet being the sum of:
  - the proportion of the P50 risk allowance that is based on AusNet's calculation of inherent risk, which we consider is not reasonable, project specific and not otherwise accounted for in the expected value; and
  - a proportion of the P50 cost allowance that is based on AusNet's calculation of contingent risk, which we consider is over-estimated or otherwise included in the direct cost base estimate[150]
- approximately 4% of the total capex, based on our assessment of cost allowances included in the direct cost base estimate that we do not consider are sufficiently justified – these include contractor project management allowances, mark-ups, and adjustments, and
- [redacted] of the total capex, being the sum of the DDP incentive and CDP incentives on average across the projects we have reviewed.

439. We consider that this overestimation bias applies to all projects, with the exception of the summer and winter network readiness project, which we accept, and the WGL project which we have determined separately.

440. We note that 9% of this overestimation (i.e. excluding the contractor incentive payment adjustment of [redacted]) closely approximates the weighted average P50 project risk allowance that AusNet has included in each of the projects that we have reviewed.

WGL Project

The BESS solution (Option 3) results in reduced capex for the next RCP and the cost of a BESS is less than AusNet has estimated

441. AusNet had proposed a relatively expensive network solution but, from the information AusNet provided, we conclude that less expensive, technically viable solutions are available with higher NPVs than AusNet's preferred approach.

150 We have based this on the risk model provided as part of AusNet response to IR079.

442. We consider that a BESS solution is preferrable. A 5MW/10MWh BESS installed early in the next RCP was determined by AusNet to be sufficient with the forecast demand growth to adequately offload the most heavily load feeder until at least 2039.

443. AusNet included $19.4 million ($2024 with overheads and other charges) for the next RCP in its economic model for the purchase, installation and connection of a BESS to a 22kV feeder. This equates to approximately $17.5 million in $2026 direct costs only. We consider that a reasonable connection cost would be materially less than AusNet appears to have assumed. For an alternative estimate for this project, we have assumed the 5MW/10MWh BESS option but a total cost 20% ($3.5 million, direct costs) less than AusNet's estimate.

444. Using an existing circuit breaker to connect the proposed new feeder and foregoing the new switchboard is also technically feasible and is likely to incur a similar capital cost to the BESS in the next RCP.

Overall alternative forecast

Our proposed 'central estimate' for an alternative forecast for the augex projects that we have reviewed in this section 4.3, is $68.3 million (or 14%) less than AusNet has proposed

445. The net result of applying the adjustments described above is to propose an alternative forecast of $421.0 million, which compares with AusNet's initial proposal of $489.3 million for demand driven augex projects (other than LV augex) assessed in this section 4.3.

446. While we have 'built up' our alternative forecast from the components of the program as AusNet has proposed, we consider that an appropriate interpretation of this forecast is that in aggregate, the proposed capex provides a reasonable overall allowance to enable AusNet to address the identified issues.

4.4 LV augex and flexible services

4.4.1 Overview of RP and AER Draft decision

In its draft decision the AER did not allow AusNet's proposed allowance of $138.5 million

447. In its RP, AusNet proposed a project to undertake a series of LV upgrades based on anticipated thermal capacity limitations arising over the next RCP, due to assumed increasing electrification of customers' premises.

448. Table 4.26 summarises the proposed expenditure in AusNet's RP and the AER's draft decision. AusNet initially proposed a capex allowance of $138.5 million, and which the AER considered lacked adequate justification.

Table 4.26: AusNet RP and AER draft decision – LV augex ($m, FY26)

Project	AusNet Proposal	AER draft decision	AER reasons
LV augex – Electrification and Flexible Services	138.5[151]	0.0	The project lacks adequately justification including insufficient analysis of potential overlaps with other proposed projects, overestimated economic benefits, and inconsistencies between cost benefit analysis assumptions and recorded data, making the analysis unreliable and unsuitable to support the proposed investment.

Source: AER draft decision, Attachment 2 – Capital expenditure, Table A.2

[151] In its RRP, AusNet refers to having initially proposed $148.5m ($2025-26) (AusNet EDPR, Revised Proposal 1 December 2025, Section 5.8.1) and refers to its current proposal as $128.5m (Section 5.8.4). These amounts appear to include

AusNet's proposal was part of a suite of inter-related programs

449. While AusNet did not categorise this project as such in its RP, in discussions with us it presented its LV augex electrification program as part of a suite of interrelated programs driven broadly by consumer energy resource (CER) impacts. AusNet explained how it had derived its forecasts for three proactive network augmentation capex projects from an interrelated suite of technical and economic models. Reflecting a CER strategy and in order to avoid duplication, AusNet stated that it had applied prioritisation across the three programs derived from this suite of models as follows:

- Priority 1: Steady state voltage compliance
- Priority 2: LV augex – electrification and flexible services
- Priority 3: CER enablement.

450. AusNet also proposed an allowance for network augmentation capex for reactive supply improvement, which it linked to the proactive Priority 1 program referred to above, under a combined business case for Voltage Compliance and Quality of Supply. AusNet further noted some overlap of drivers between all of these programs and a proposed allowance for its summer and winter network readiness program.

451. Finally, AusNet proposed an ICT capex allowance for a Distribution System Operator (DSO)/Future Services Hub, for which it put forward a separate business case. This business case effectively allowed for non-network solutions, including flexible services, which AusNet sought to take into account as 'offsets' to the network initiatives otherwise required.

452. In its draft decision, the AER determined expenditure allowances for some of the above suite of programs that AusNet had proposed. However, the AER did not provide an allowance for the proactive LV augex project that AusNet had proposed.

4.4.2 Overview of AusNet's RRP

Proposed RRP expenditure allowance

AusNet has re-proposed a proactive LV upgrade program, now at a cost of $120.1 million

453. In its RRP, AusNet now proposes a proactive program allowance of $120.1 million for LV augex for 'electrification and flexible services', as we show in Table 4.27. AusNet has substantially relied on similar economic analysis to that which it utilised for its initial proposal, and which we describe further below.

454. AusNet describes the purpose of this program as follows: [152]

> *'The scope of this business case is to mitigate EUE associated with network import limitations driven by electrification at the low-voltage distribution substation and SWER network levels.'*

Table 4.27: Demand-driven augex projects – LV augex ($m, June 2026)

Project	FY27	FY28	FY29	FY30	FY31	RCP total
LV Augex (Electrification & Flexible Services)	30.6	29.0	16.2	29.8	14.4	**120.1**

Source: EMCa derived from ASD – AusNet Distribution – SCS Capex Model – 011225 - CONF

network overheads. In line with our general protocol, we refer to direct costs, in $2026 terms as escalated by AusNet in its SCS capex model but not including allocated overheads.

152 AusNet business case for Demand driven augmentation in the LV network and flex ble services, 1 December 2025 ('AusNet's business case'). Page 7.

RRP relationship with other programs

For our current assessment, we make the working assumption that AusNet undertakes other related programs as it has proposed

455. In our current scope of work, we have been asked to review AusNet's revised proposal for LV augex (this section) and its Summer Winter Network Readiness Program (for which we refer the reader to Section 4.3.3). For the purpose of the current assessment, we make the working assumption that the AER allows AusNet's proposed expenditure for the other related programs referred to above; to the extent that it does not, this may alter conclusions that we draw here on its LV augex program.

456. Whereas AusNet previously referred to its LV augex program as 'Priority 2', with Steady State Voltage Compliance as its first priority initiative, it now states that its LV augex is first priority, with CER enablement the second priority.[153]

457. While not within our scope, but since AusNet had described a relationship between these programs, we note that AusNet has accepted the AER's draft decision not to allow a proactive Steady State Voltage Compliance program. However, it has now increased its proposed allowance for reactive supply improvement from $9.0 million (of which AER included $8.7 million in the capex allowance) to $24.7 million.[154] While the objective of AusNet's reactive supply improvement program is voltage compliance, we expect that some projects that rectify undervoltage may also address the thermal overload issues that we are assessing under our current scope, and vice versa.

Factors that AusNet presents as drivers

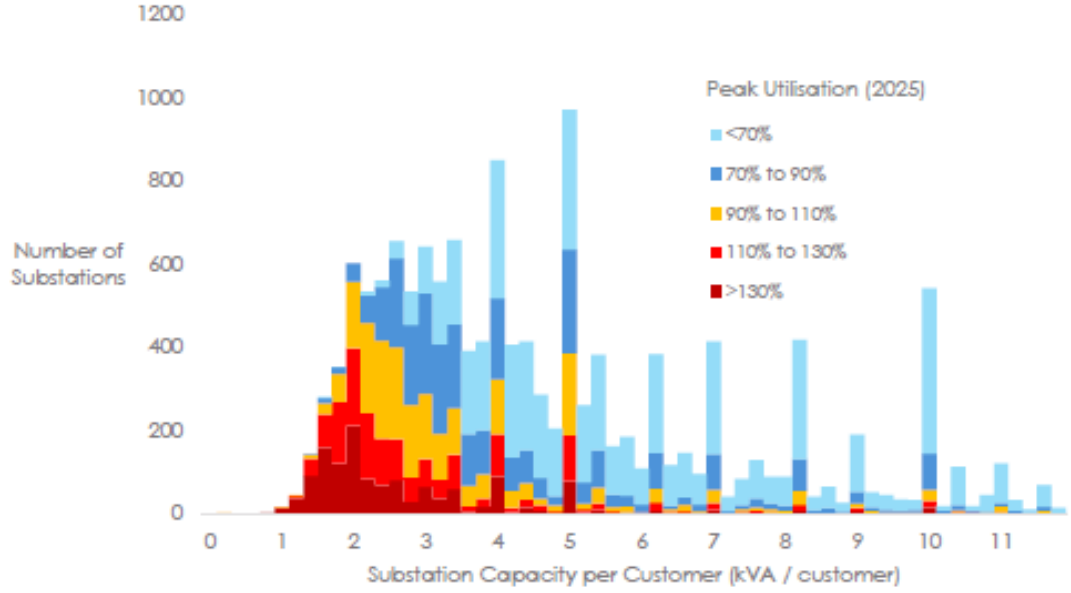
AusNet presents increasing electrification, against levels of substation overloads, as the key drivers for its proposed program

458. In its business case, AusNet identifies an emerging trend in changing load patterns due to electrification, and notes that there is a lack of diversity at the LV level. AusNet describes the spread of utilisation factors for its LV substations (distribution substations, DSS and single wire earth return, SWER) and notes that a proportion of its substations face maximum demands that exceed their rated capacities. As we show in Figure 4.28 and Figure 4.29, AusNet presents information that shows that the more 'overloaded' substations tend to be both smaller and older than the average.

153 EDPR business case for Demand driven augmentation in the LV network & flexible services (1 December 2025). Page 7. (Unless otherwise stated in our current report, our references to AusNet's business case refer to this document).

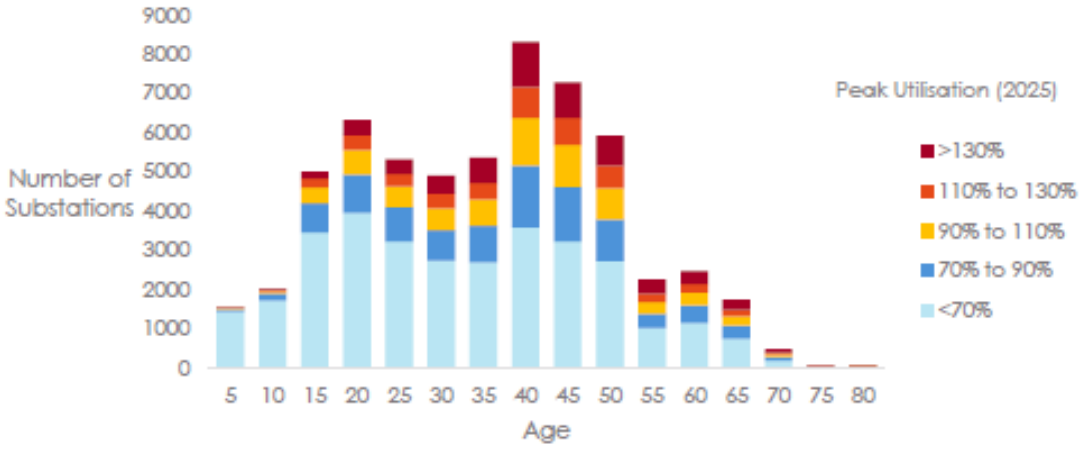
154 AusNet EDPR RRP. Sections 5.14.3 and 5.14.4. Table 50). The amounts referenced here appear to include overheads; from AusNet's SCS capex model its proposed allowance for Supply Improvement in $2026 direct cost escalated terms, is $23.1m. (model block 48).

Figure 4.28: Distribution substation utilisation factor by average capacity per customer (2025)



Source: AusNet business case, figure 6

Figure 4.29: Distribution substation ages and peak demand (as of 2025)



Source: AusNet business case, figure 9

459. AusNet estimates that, in the 2025 financial year, *'…approximately 174.05 MWh of energy went unserved due to outages resulting from electrical or thermal overloads*.'[155]

Overview of AusNet's forecasting approach

AusNet has forecast what it claims to be an economic level of proactive LV upgrades based on 'energy at risk'

460. AusNet has developed SWER and LV models which it uses to forecast '…*expected energy at risk for each network asset*'. From this, AusNet uses a '*VCR methodology'* applied to '*identified import ratings*', from which it identifies a '*preferred option for each location'* and develops *a 'program of works of the most economically viable projects*.'[156]

461. AusNet considers the options shown in Table 4.28 and which summarises the costs and benefits of these options. Options 1 and 2 effectively achieve the same outcomes (as is

[155] AusNet LV augex business case. Page 13.

[156] AusNet LV augex business case. Page 18. Figure 15.

seen by the PV benefits) but Option 2 has lower capex because it assumes the avoidance of some network augmentation capex by relying on flexible services.

462. AusNet's comments state that Option 2 has the highest NPV. Its analysis shows that Option 3 has the highest NPV, however in its business case AusNet dismisses Option 3 due to its high cost and we concur with this reasoning.

Table 4.28: AusNet's summary of options considered ($m, real June 2024)

Option	Capex	Opex	PV Benefits	NPV	AusNet comment
Do nothing	0.0	0.0	0	0	This option does not address the identified need
Option 1: Economic network augmentation	121.2	2.6	1,559	1,444	This is not the preferred option as it is not least cost
Option 2 (preferred): Economic network augmentation and flexible services	104.3	2.4	1,558	1,467	This is the preferred option as it maximises NPV
Option 3: Deterministic augmentation	502.5	10.0	2,038	1,563	This is the most expensive option

Source: EMCa, summarised from AusNet business case, table 22 (page 27)

463. We consider that AusNet has selected an appropriate option at the descriptive level; that is, to undertake some network augmentation and also to take account of flexible services. Our assessment which follows therefore focuses on this option.

4.4.3 Assessment

AusNet's EUE methodology

AusNet's EUE calculation is not a valid measure of energy unserved

464. Our primary concern with AusNet's methodology is that it conflates the risk of an outage, with an assumed actual outage, for which it then quantifies a cost based on VCR based on its estimate of the EUE.

465. In its methodology document, AusNet describes its calculation of the value of EUE based on formulas which we reproduce in Figure 4.30.

Figure 4.30: AusNet's description of its calculation for EUE at Risk

Calculation of Unserved Energy at Risk

Load at Risk $_{(y)}$ (kW) = Max [0, Maximum Net Demand_$_{10POE\ (y)}$ (kW) – Import Rating (kW)]

Where,

- Import Rating (kW) is as defined and calculated in Section 4.3.1.
- Maximum Net Demand (kW) is the annual 10POE forecast maximum demand as seen by the distribution substation.

$$Unserved\ Energy\ at\ Risk_{POE\ (y)}\ (kWh\ pa) = \frac{1}{2}\sum_{hh=1}^{17520} F_{hh}\ x\ max[0, Load_{POE}\ (kW)_{(hh,y)} - Import\ Rating\ \ (kW)\ ]$$

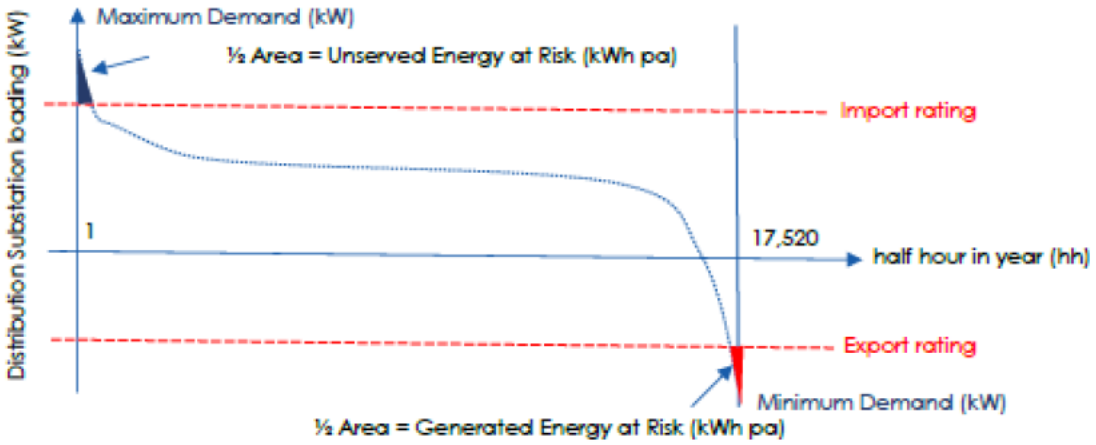
Calculation of Value of Expected Unserved Energy

Value of Expected Unserved Energy $_{(y)}$ ($) = Expected Unserved Energy $_{(y)}$ (MWh) x VCR ($/MWh) x CPI Escalation

Source: AusNet Hosting capacity, electrification and CER enablement methodology (13 November 2025), Section 4.4.2

466. AusNet further illustrates its methodology in the diagram that we reproduce as Figure 4.31. We observe from this that AusNet effectively treats as 'unserved' all energy in its forecast load duration curve, above the relevant 'import rating' of the asset.

Figure 4.31: Example load duration curve and energy at risk

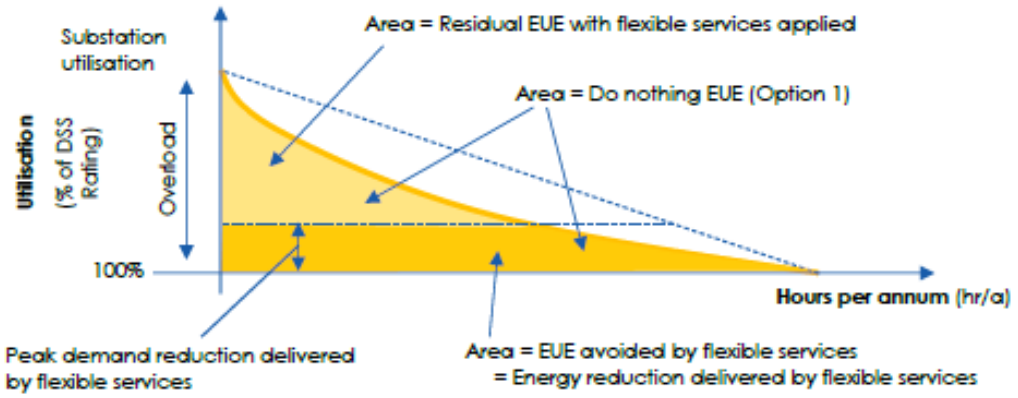


Source: AusNet Hosting capacity, electrification and CER enablement methodology (13 November 2025), Figure 5

467. In its methodology document, AusNet defines the '*thermal limitation*', which it equates to the '*import rating*' referred to in the diagrams above, as '*120% of the cyclic rating of the distribution substation's transformers*'.[157] We sought further clarification from AusNet as to how it defined the import rating, relative to the description of '*overload*' that it included in the diagram that we reproduce as Figure 4.32, and which effectively expands on the 'top end' delineation of Unserved Energy at Risk in Figure 4.31.

157 AusNet hosting capacity methodology. Section 4.3.1.

Figure 4.32: Reduced EUE provided by flexible services



Source: AusNet Hosting capacity, electrification and CER enablement methodology (13 November 2025), figure 12. This diagram is also figure 16 in AusNet's business case.

468. In its response, AusNet states that: [158]

> *'The Expected Unserved Energy (EUE) risk for Demand driven augmentation in the LV network and Flexible Services is quantified as the energy at risk when an asset's load exceeds 120% of its cyclic rating.'* Also, that '*The 120% capacity acts as a hard limitation in our model. Unserved energy is calculated using the load duration curve…'*

469. AusNet further clarified its incorporation of the impact of flexible services into this definition, as follows:[159]

> *'EUE (with DSO) is calculated by assuming Flexible services is [sic] effective up to 6% overload (Table 25 in the business case) increasing the threshold when energy is unserved from 120% cyclic rating to 127.2% (120%*106%) of cyclic rating.'*

AusNet's approach conflates the risk of energy unserved, with an assumption that such energy is (or will be) unserved

470. AusNet's response confirms that in its modelling of the economic case for proactively addressing thermal overloads, AusNet has assumed that customer demand above a threshold given by 120% of the cyclic rating of a DSS (and after allowing for a further 6% cushion for flexible load services) is unsupplied. We consider that this is not a valid representation of the impact of DSS (or SWER) overloads, as we expect that:

- the relevant substations tend to continue supply even while loaded above their ratings, though the ***risk*** of a supply failure would tend to increase, particularly with multiple such overloads; and
- if supply does fail due to thermal overload, then it is also not valid to assume (as is the case in AusNet's modelling) that supply returns again once the demand reduces below the asset's rating.

471. In summary, AusNet's modelling does not provide a valid representation of EUE and, therefore, of the economic costs associated with current overloads or any increase in overloads that might occur due to increasing electrification. This factor is critical to the validity of its economic analysis, since it is AusNet's forecast of EUE that drives the economic benefits that it claims as justification for its proposed program.

158 AusNet response to IR069. Question 10.

159 AusNet response to IR075. Question 6.

AusNet's description of its operational processes

AusNet has confirmed that its current operational practices for LV asset overloads are a reactive approach to replacing or upgrading following a fault or failure

472. To confirm our understanding of what appeared to be a mismatch between AusNet's modelling and a valid representation of a 'do nothing' counterfactual, we asked AusNet to describe its current operational processes regarding DSS overloads. We reproduce AusNet's response in Figure 4.33.

Figure 4.33: AusNet description of operational practices where a DSS or SWER fails (e.g. due to thermal overload)

> *Step 1. A fault occurs on our LV network. It is assessed by field crews and the reason for the fault is noted in our system. Reasons include: thermal overload, extreme weather, tree/bark, vehicle/third party.*
>
> *Step 2. Our BAU operational response to faults on the LV network involves assessing solutions to rectify the issues ASAP, which is a like-for-like replacement, or repair the asset, rather than upgrade.*
>
> *In the event of an LV outage/fault, our current restoration process does not involve assessing if an upgrade should be considered as the aim is to restore customers quickly. An assessment to determine if the preferred solution should be an upgrade to the asset is not feasible because an economic assessment and detailed design would be required.*
>
> *Step 3. Following restoration, our current network planning approach involves reactively upgrading a subset of our overloaded assets where they have led to outages/faults as a result of thermal overload AND where they are economically justified (through unserved energy x VCR). In 2025-26, this includes planned upgrades for 40 distribution substations.*

Source: AusNet response to IR075, Question 1

473. AusNet's response confirms our understanding that its operational process is that its LV assets are effectively 'run-to-fail' rather than being upgraded based on thermal overload alone. This is standard industry practice for such assets. However, the implication is that unserved energy results from a fault or failure of the asset, and the time taken to restore supply, rather than (as AusNet has modelled) resulting directly from an overload relative to the asset's rating.

474. We invited AusNet to provide information on LV faults from thermal overloads, such as it refers to occurring in the information shown in Figure 4.33. AusNet responded that:

> *'…the information provided in IR075 [i.e. as shown in Figure 4.33] relates to our current process. In our next RCP, we have not proposed to continue the above approach...'*
>
> *(w)e quantified the reduction in unserved energy by looking at the counterfactual, what is the amount of unserved energy above the asset's rating if we do not proactively upgrade.'*[160]

The operational approach that AusNet describes is not the counterfactual that it has adopted in seeking to provide an economic justification for its proposal

475. AusNet's response confirms our understanding of the basis for its modelling. Specifically, it confirms that what it has defined as its counterfactual does not represent a continuation of

[160] AusNet response to IR090.

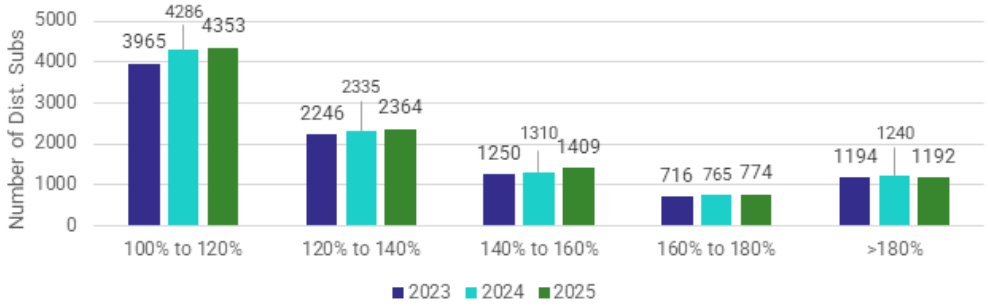
its current operational practices, and that it has treated energy supplied above an asset's rating as 'unserved'. For both reasons, we consider that its economic modelling is not valid.

Information on the extent of DSS overloads

As we would expect with most DNSPs, AusNet currently operates with a proportion of its distribution substations experiencing levels of overload at certain times

476. We sought to test AusNet's assumption that its' DSS would cease providing supply at utilisation greater than 120%. AusNet provided the information in Figure 4.34, showing the utilisation factors for those substations where it is greater than 100%.

Figure 4.34: Distribution substation (DSS) utilisation factors



Source: AusNet, response to IR079, Q28

477. While we do not suggest that it is necessarily desirable to plan to operate DSS assets significantly beyond their thermal ratings, AusNet's information nevertheless shows (as we would expect) that under a run-to-failure policy, there are a number of DSS assets that are operated (at least for some periods of time) above those ratings.[161] We also observe that, while the data shows slight increases in overloaded substations, there is not a significant trend over the three years of data provided.

478. This information suggests to us that it is an overestimate to assume, as AusNet has done, that loads will be unsupplied where and when loads exceed 120% of thermal ratings (even after allowing for the '6%' benefits from flexible services). By comparison with the numbers of DSS loaded above 120% shown in this data, AusNet advises that it chose to upgrade only 40 substations in FY26.[162]

Information on the extent of faults and resulting unsupplied energy due to thermal overloads

AusNet provided information on faults resulting in outages due to thermal overloads; however, this is a different cause of unserved energy than AusNet has modelled and appears to be less

479. Given AusNet's responses on its economic modelling, we sought information on the current level of unserved energy resulting from faults caused by thermal overloads. As we noted in our review of its RP, AusNet had provided conflicting information regarding the current extent of unserved energy resulting from DSS faults due to thermal overloads, ranging from 12.8MWh to an amount of the order of 8,000MWh.

480. In response to our information request,[163] AusNet advised that it had identified data quality issues with the information provided previously and that it reviewed and corrected relevant

161 Utilisation data in itself does not provide insight into the extent of DSS overloads, either in terms of their frequency or duration. Both of these would be factors in defining increasing risk of DSS failure due to thermal overload, not just the maximum overload alone.

162 AusNet response to IR090. Question 3.

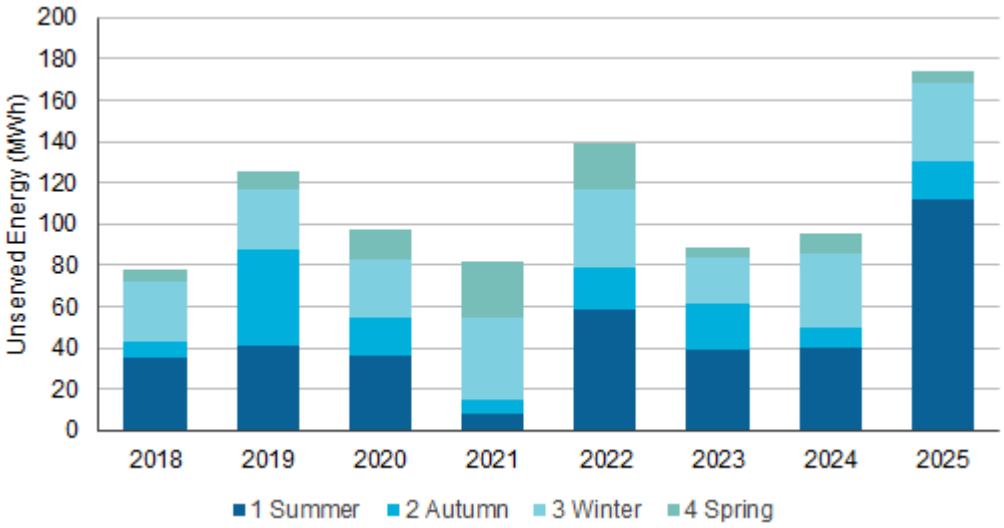
163 AusNet response to IR069. Question 13.

data. AusNet advised that in FY25 its actual unserved energy from DSS overloads was 174MWh.[164] AusNet claimed that this was closely aligned with its modelling estimate of 259MWh for FY26, though we would tend not to accept that this is a close correlation. In any case, we would tend to consider any correlation as largely coincidental, since the method by which AusNet has modelled unserved energy does not reflect the actual causes.

While its unserved energy due to DSS thermal overloads was higher in 2025 than in previous years, this does not seem to be due to an increasing number of faults

481. To improve our understanding of the situation, we sought further historical information. In Figure 4.35 we show the results of our analysis of this information. We observe that typically the amount of unserved energy due to DSS thermal overloads has been of the order of 100 to 110 MWh, with no clear upward trend up to 2024. The cause of the significantly higher value in 2025 can only be surmised, though it is possible that it may indicate the beginning of a trend increase that could be due to electrification.

Figure 4.35: Historical unserved energy arising from DSS faults due to thermal overload

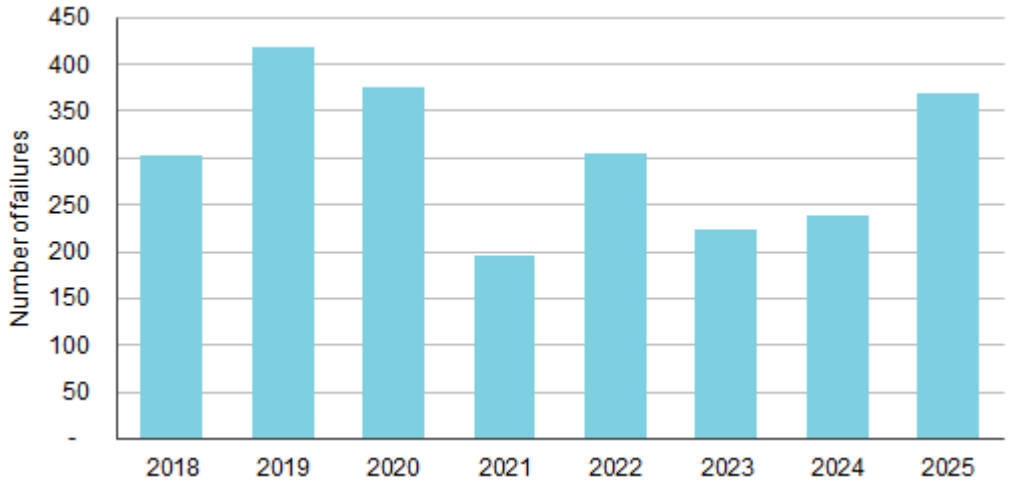


Source: EMCa analysis from AusNet information provided as Attachment 1 to its response to IR75

482. From AusNet's data, we also determined the number of DSS faults that it ascribed to thermal overloads, which we show in Figure 4.36. This data similarly does not suggest an upwards trend and suggests that the higher unserved energy shown in Figure 4.35 for 2025 appears to be largely a function of presumed higher average unserved energy per fault and not an unusually high number of such faults.

[164] AusNet response to IR075. Question 4.

Figure 4.36: Historical DSS faults due to thermal overload



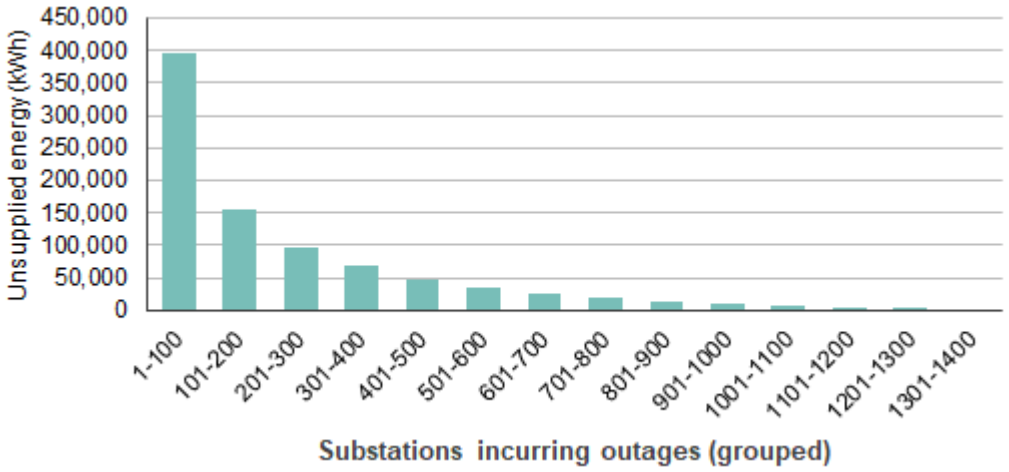
Source: EMCa analysis from AusNet information provided as attachment 1 to its response to IR075

A small number of AusNet's substations appear to be responsible for a disproportionate amount of unserved energy due to thermal overloads

483. We also sought to understand from AusNet's data, the distribution of unserved energy arising from the outages caused by thermal overload faults that occurred. As shown in Figure 4.37, we find that the unserved energy that AusNet has recorded as resulting from thermal overloads is highly concentrated in faults that occurred in a relatively small number of substations. Specifically:

- AusNet's data shows that over the period (i.e. 2018 to 2025) there were 2,427 faults leading to outages, across 1,377 distribution substations. In other words, some substations had more than one thermal overload fault in the period.
- Taking the substations individually, almost half of the unserved energy (396MWh out of 881MWh) arose from 100 of the 1,377 substations that suffered a fault caused by a thermal overload.

Figure 4.37: Unserved energy ranked and grouped according to unserved energy, across distribution substations (DSS) that incurred outages/faults due to thermal overloads (2018 to 2025)



Source: EMCa analysis from AusNet information provided as attachment 1 to its response to IR075

Relative to the proportion of highly loaded substations, the proportion of annual faults due to thermal overload is small

484. We also considered this fault/outage information by reference to the information that AusNet provided on its substation utilisation factors (as shown in Figure 4.34). As we show in Table

4.29, AusNet's data indicates that around 9.4% of its substations have utilisation factors greater than 120%, and that on average over the past eight years, 3% annually of these substations (i.e. those with utilisation >120%) have incurred a fault leading to an outage.

485. While we expect substations that are more highly and more frequently overloaded to have a higher rate of faults leading to outages, this evidence suggests that it is far from axiomatic that substations with utilisations of greater than 120%, will result in unserved energy.

Table 4.29: Relationship of LV substation faults to substation utilisation

Description	Value
Total number of substations	60,875
Number of substations with utilisation > 120%	5,739
Percentage of substations with utilisation > 120%	*9.4%*
Number of substations that incurred an outage due to thermal overload (2018 to 2025)	1377
Implied average annual affected substations	172
Annual proportion of substations incurring fault (as a proportion of substations with utilisation > 120%)	*3.0%*

Source: EMCa analysis. Total number of substations is indicative of the current number from AusNet's economic model. Other data sourced from AusNet's responses to IR075 (attachment 1) and IR079 Question 28.

Indications of relative risk

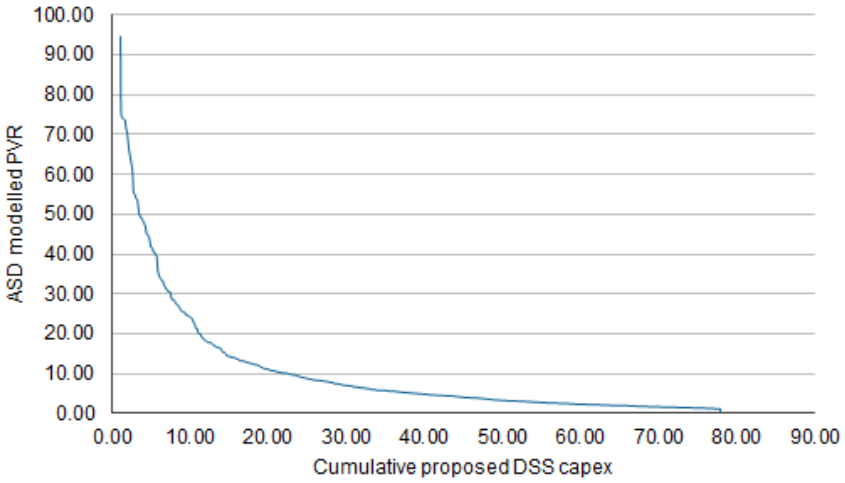
AusNet's modelling does provide some indication of the relative levels of risk

486. While we consider that AusNet's modelling is not valid as a means of directly determining an economic program of proactive upgrades, it does indicate the relative extent of forecast overloads at the LV level, and this would seem to be indicative of the relative levels of risk at each asset. As an example, we have analysed the projects that AusNet has proposed according to the Present Value Ratios (PVR) by which AusNet has ranked them.

487. We present the results in Figure 4.38 (for DSS upgrades) and Figure 4.39 (for SWER upgrades). For the DSS upgrades, in order to provide visibility of the relationship, we have excluded the top six projects, which have PVRs of more than 100, with the largest having a PVR of more than 1,000 times.

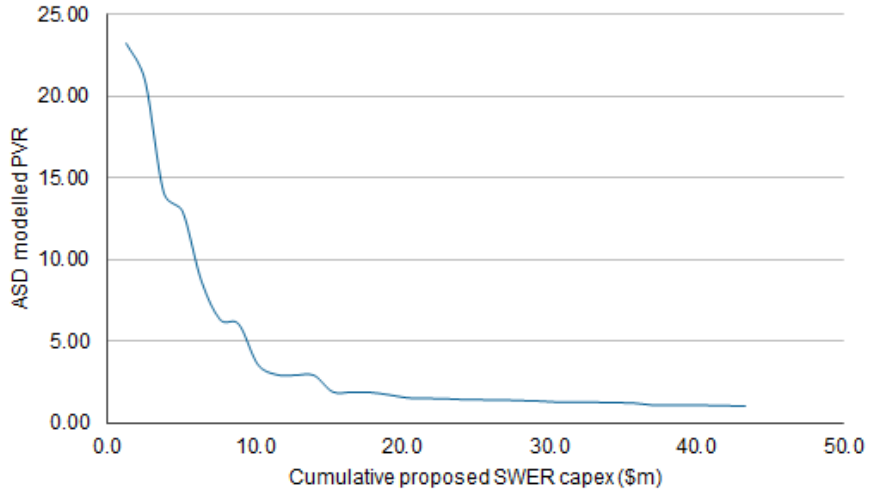
488. While we stress that we consider that the economic analysis that leads to PVRs from AusNet's modelling are not a valid representation of the economics of the proposed projects, their relativities could be considered an indication of ***relative*** risk levels caused by thermal overloads. With this in mind, the results suggest that a small number of projects may at least be candidates to consider the merits of a pre-emptive upgrade. But the corollary to this is that there is a much larger number of projects (by value) for which the risk levels are less by factors of several times, or in some instances several orders of magnitude.

Figure 4.38: AusNet's modelled PVR against cumulative capex ($m), for DSS



Source: EMCa, from cost and benefit information combined from AusNet's Demand driven augex LV network model, and its Economic Model - Electrification

Figure 4.39: AusNet's modelled PVR against cumulative capex ($m), for SWER



Source: EMCa, from cost and benefit information combined from AusNet's Demand driven augex LV network model, and its Economic Model - Electrification

4.4.4 AusNet's recent augex on LV Network

In response to thermal overloads, AusNet has undertaken only augex involving only reactive replacements and reactive upgrades in the period from 2022 to 2026

489. We asked AusNet to advise the recent and current levels of LV network augex resulting from thermal overloads. AusNet provided the information on DSS as shown in Table 4.30.[165] This information makes evident the significant increase in upgrades that AusNet forecasts as being economically justified under its proposed move to a proactive program, relative to its requirements under its current (reactive) approach.

490. The information also shows that the 55 combined reactive replacements and reactive upgrades in FY26 due to thermal overloads, would be considerably more than in previous years.

[165] AusNet response to IR090. Question 4.

491. AusNet's information further shows that its replacements and upgrades due to thermal overloads have to date been much less than age/condition-based replacements, though this relativity would change markedly if it was to adopt its proposed proactive upgrade program.

Table 4.30: AusNet information on LV DSS historical and forecast volumes[166]

		FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Repex	Reactive and proactive like for-like replacement due to age/condition	332	283	379	499	372	362	359	362	374	372
Augex	Reactive I ke for-like replacement due to thermal overloads	31	26	20	35	15					
Augex	Reactive upgrade due to thermal overloads	0	0	0	0	40	0	0	0	0	0
Augex	Proactive upgrades due to thermal overloads						180	237	138	105	99
TOTAL		**363**	**309**	**399**	**534**	**427**	**542**	**596**	**500**	**479**	**471**

Source: AusNet response to IR090, Question 4

492. AusNet advises that in FY26 it has spent (or at least plans to spend) [redacted] million on the 40 DSS reactive upgrades indicated in the table, at a unit cost therefore of [redacted][167]

AusNet did not undertake any such upgrades in its SWER network

493. In its same response, AusNet advised that the information shown above is for DSS only and that it has undertaken '*…no SWER in (the) current period*'.[168]

4.4.5 Summary of findings

AusNet has not justified undertaking a proactive upgrade program

494. AusNet has proposed to move from a program of reactive upgrades following thermal overload faults to proactively upgrading DSS and SWER to address an increase in EUE that it forecasts as resulting from increased electrification. AusNet has undertaken equivalent modelling that covers both its DSS assets and its SWER assets.

495. We consider that AusNet has not demonstrated that it is beneficial to move from its current approach of considering upgrades following faults or failures, to adopting a proactive approach. This is because the counterfactual against which AusNet has sought to demonstrate the economic benefits of its proposed approach conflates the ***risk*** of unserved energy due to higher utilisation factors, with an assumption that demands that would lead to overloaded assets, will be unsupplied. AusNet has provided ample evidence that this is not the case and therefore its claimed economic modelling does not provide a justification for the proactive programs that it proposes.

166 AusNet advised that it had no equivalent historical program for SWER.

167 AusNet response to IR090. Question 3.

168 AusNet response to IR090. Question 3.

4.4.6 Alternative forecast

Distribution Substations (DSS)

A basis for an alternative forecast is to consider AusNet's current-year reactive DSS expenditure, modified by considering the extent of DSS deferrals

496. Since we have concluded that AusNet's claimed justification for its proposed proactive program is not valid, we consider that the only information from which we can infer a reasonable forecast is to consider AusNet's current expenditure, noting that this is for reactive replacements and upgrades.

497. In recognition of the likelihood that increased electrification is likely to require greater expenditure than has been the case until recently (e.g. FY22 to FY25), we propose utilising AusNet's FY26 volume and expenditure as a basis for an alternative forecast. For this purpose, we have also therefore pro-rated the cost that AusNet advised for the 40 reactive upgrades, to include an allowance for the 15 reactive replacements undertaken in that year.

DSS deferrals

It is reasonable to allow for deferrals due to flexible services, but these will be less to the extent that less network upgrades are allowed for

498. AusNet has allowed for a proportion of the proactive upgrades that it has proposed, to be deferred by 'flexible services'.[169] Such deferrals are also relevant in considering an alternative forecast, although the extent of such deferrals would be reduced to the extent that the underlying network DSS upgrade program is less than AusNet has proposed.

SWER

AusNet has not justified inclusion of an allowance for SWER upgrades

499. AusNet has not undertaken any SWER upgrades to date. While it may be that AusNet finds a justification to undertake such upgrades in future, it did not demonstrate this in its RP and similarly has not provided a valid justification in its RRP. With evidence that it has not historically undertaken such work, it is reasonable to infer that it has to date been unable to justify this internally, therefore there is also not a historical precedent of prudently justified work that may be considered in providing an allowance for the next RCP.

500. Having not justified this component of its proposed allowance, we consider that this component of AusNet's proposed allowance does not meet the relevant NER technical/economic criteria to support its inclusion in an alternative forecast.

Overall alternative forecast

The central estimate of our proposed alternative forecast is $26.4 million

501. The net result of applying the adjustments described above would result in an alternative forecast central estimate of $26.4 million for LV augex, which is $93.7m (78%) less than AusNet's revised proposal of $120.1 million. This compares with AusNet's initial proposal of $138.5 million, noting that the AER disallowed this entirely in its draft decision.

Commentary on alternative forecast

502. While we have 'built up' our alternative forecast from the components by which AusNet had proposed it, we consider that an appropriate interpretation of this forecast is that the aggregate amount (i.e. $26.4 million) is a reasonable central estimate for an overall

[169] In its business case for LV augex and flexible services, AusNet has not provided a capex allowance for flex ble services. This is inherent in its 'DSO' proposal. For the purpose of our scope, we assume that AusNet proceeds with introducing flexible services as it proposes.

allowance to enable AusNet to address thermal overload issues that arise in its LV network due to increased electrification over the period. Taking account of relevant factors, we would tend to the view that an allowance would be reasonable within a range from $20 million to $35 million over the period.

503. We consider it likely that AusNet will find that the balance between proactive and reactive work will vary from the amounts that we have utilised in arriving at an alternative forecast. AusNet may also find that there is a case for some such LV network upgrade expenditure to be applied to its SWER network. We expect that AusNet will continue to monitor data on LV load levels, consumer behaviours and usage patterns, deployment of behind the meter technologies and the ways in which consumers operate them and that this information will assist in defining and undertaking a prudent suite of programs over the period, including the introduction of its own flexible service options.

4.5 Safety augex

4.5.1 Overview of AER's draft decision

504. In its draft decision, the AER accepted the Fall arrest systems project,[170] which we present in Table 4.31.

Table 4.31: RP and AER draft decision – Fall arrest systems augex ($millions 2025–26)

Projects	Proposal	AER draft decision
Fall arrest systems	7.9	7.9

Source: EMCa derived from AER, Attachment 2 – Capital expenditure | Draft decision – AusNet Services distribution determination 2026-31, Table A.4

4.5.2 Overview of RRP

505. AusNet has proposed an increase to the Fall arrest systems project, with it now totalling $8.3 million in the next RCP, as shown in Table 4.32.

Table 4.32: Safety augex projects within our scope of review ($m, June 2026)

Project	FY27	FY28	FY29	FY30	FY31	RCP total
Fall arrest systems	1.7	1.5	1.6	1.5	2.0	**8.3**

Source: EMCa derived from ASD – AusNet Distribution – SCS Capex Model – 011225 - CONF

506. In addition, AusNet has included a second safety driven project, as shown in Table 4.33. AusNet has now included the Codified FOLCB replacement (repex) project in its categorisation of augex, which we review in this section.

Table 4.33: Safety repex projects within our scope of review ($m, June 2026)

Project	FY27	FY28	FY29	FY30	FY31	RCP total
Codified FOLCB replacements	1.6	1.6	1.6	1.6	1.6	**8.0**

Source: EMCa derived from ASD – AusNet Distribution – SCS Capex Model – 011225 - CONF

[170] AER, Attachment 2 – Capital expenditure | Draft decision – AusNet Services distribution determination 2026-31. Page 44.

4.5.3 Assessment of Fall arrest systems

507. Based on our reading of the RRP, AusNet states that it accepts the AER draft decision in relation to the Fall arrest system project and does not provide any supporting documentation in the RRP to support the apparent increase in cost from $7.9 million to $8.3 million.

508. We asked AusNet to provide justification for the proposed capex, because it is an increase from the AER's draft decision. In its response, AusNet confirmed that it had accepted the AER's draft decision with the increase [redacted]

[redacted]

509. We confirmed that the direct capex component for this project expressed in $2024 and prior to AusNet's allocation of TOMSA support costs is unchanged from the RP and the RRP.[173] On that basis we consider that the scope and direct cost of the proposed project is consistent with the draft decision. The change in allocation of the TOMSA support costs, and which explains the apparent difference in the proposed cost for this project between the RP and the RRP, is beyond the scope of our review.

4.5.4 Assessment of Codified FOLCB replacements

What AusNet has proposed

510. AusNet has proposed $8.0 million for Fused Overhead Line Connection Boxes (FOLCB) replacements in codified areas, supported by a business case. This project was not included in its RP.

511. AusNet states that there was a significant rise in Ignition Reduction Units (IRU) failures on FOLCBs in 2025,[174] '*including failures that occurred in codified areas during periods of high fire danger rating. This has significantly increased the risk of continued use of FOLCBs with this failure mode in these areas*.'

512. In response, AusNet has proposed the proactive replacement of 9,003 FOLCBs within codified areas over the next RCP with the Sicame PFV type 100A Fuse Disconnectors.

Our assessment

AusNet is subject to the F-factor scheme which acts as an incentive to reduce fire starts

513. The AER describes the F-factor scheme as providing an incentive on DNSPs to lower the number of fire starts on the network:[175]

> *'The f-factor scheme is a regulatory instrument under the National Electricity (Victoria) Act 2005, which provides Victorian DNSPs with an incentive to lower the number of fire starts on their networks. The Victorian Government introduced the f-factor as one of several measures in response to the 2009 Black Saturday bushfires. Its objective is to reduce harm to human life and property by powerline-caused bushfires, without imposing additional costs on consumers.'*

171 AusNet's response to IR#069. Question 5.

172 AusNet's reference to $8.9 million corresponds to total escalated costs including overheads.

173 ASD - AusNet Distribution – SCS Capex Model - 011225 - CONFI(31102288.1), START – Input| projects worksheet.

174 ASD – AusNet – FOLCBs – 1Dec2025. Page 1.

175 Attachment 10 – Victorian F-factor incentive scheme | Draft decision – AusNet Services distribution determination 2026-31. AER. Page 1

514. The targets are set out by the Victorian Government, with the scheme administered by the AER to be applied as a revenue adjustment in each regulatory year in accordance with the National Electricity (Victoria) Act 2005 F-factor Scheme Order 2016.[176]

515. For the purposes of our assessment, we consider whether the proposed program is prudent and efficient, rather than discuss the application of revenue recovery methodologies. However, to the extent that reporting of the F-factor scheme assists with understanding the current level of performance, we have included that in our assessment.

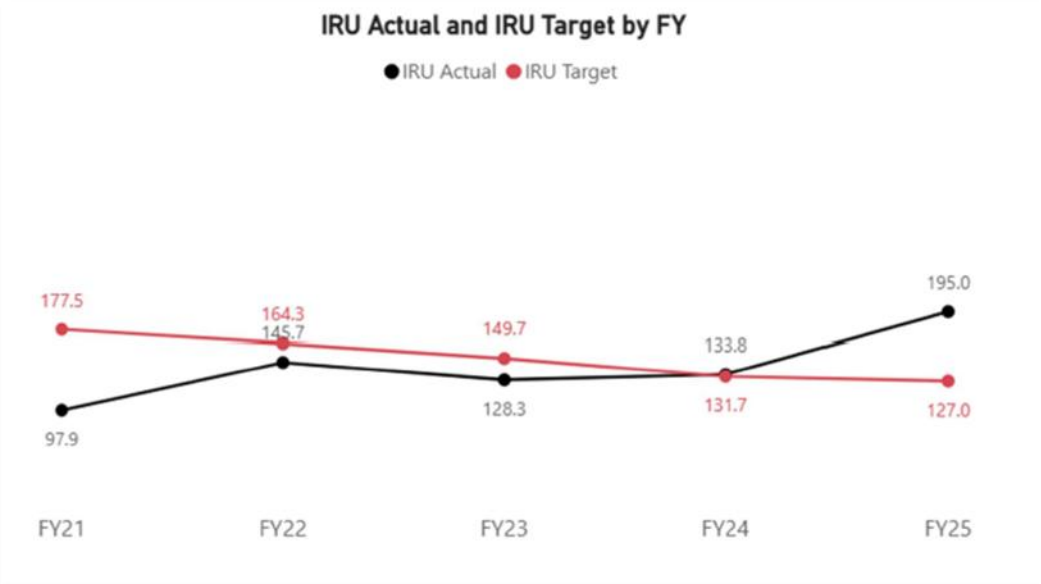
Recent reporting against the F-factor scheme indicates that AusNet's fire start performance is declining

516. The IRU is a key metric under the Victorian F-Factor scheme which measures the consequence of fire starts, and not the number of fire starts. To assist understand the trend of IRU, AusNet states that:[177]

> *'An upward trend in IRU signals heightened bushfire risk, even when the overall number of fire starts remains steady or declines.'*

517. AusNet's reporting of IRU shows an increasing trend of safety risk as measured by F-factor performance as shown in Figure 4.40.

Figure 4.40: 5-Year F-Factor Performance - Ignition Reduction Units - Actuals versus F-Factor Target



Source: ASD – AusNet – FOLCBs – 1Dec2025. Graph 2.

518. The F-factor target for FY26 was set as 121.1 for AusNet,[178] reflecting a further improvement on the targets indicated in Figure 4.40.

519. AusNet also states that the key sources[179] of IRU in 2025, are FOLCB/isolators (58.4, or 30% of the total) followed by HV fuses (45.9, or 24%) then vegetation (17%). The remaining sources contribute less than 30% in aggregate. The increase is attributed by AusNet to:[180]

176 https://www.aer.gov.au/publications/reports/performance/victorian-electricity-distr butors-fire-start-reports-july-2023-june-2024-reporting-period

177 ASD – AusNet – FOLCBs – 1Dec2025. Page 5.

178 Victorian Government Gazette No. G 26, Wednesday 18 June 2025.

179 Descr bed by AusNet as causes of IRU.

180 ASD – AusNet – FOLCBs – 1Dec2025. Page 6.

'…the multiple FOLCBs that failed during high bushfire risk days in the highest consequence days significantly raised the risk of these assets remaining in areas of high consequence and operating on high bushfire risk days.'

520. In its RRP, AusNet also states that '*FOLCBs ranks third as the cause of fire starts on our network, with an average of 15 fire starts p.a. since 2020.*' [181]

521. Following an internal review and consultation with manufacturers, including testing of the existing units:[182]

'AusNet together with other Victorian DB's has requested FOLCB supplier Flowline to conduct a temperature rise test. The current FOLCB failed the test when 16mm$_2$ Cu cable (AusNet standard customer mains) were installed with temperatures reaching levels that is detrimental to the cable insulation. Excessive temperatures will lead to increased power dissipation of fuse links.'

522. AusNet concluded that the only practical strategy is a progressive replacement of FOLCBs with 16mm² conductors in high bushfire risk areas over a 10–15 year period, commencing with codified areas.

Failure of FOLCBs can start a fire

523. AusNet states that FOLCBs are also used to connect overhead service cables where it is located at the customers point of attachment. When FOLCBs fail, they can start fires due to the release of burning plastic that falls to the ground. AusNet has identified that the primary failure modes arise from elevated power dissipation in fuse links under high loading and thermal stress. We consider that the emergence of this issue in 2025 has led to the development of the proposed proactive replacement option.

524. We understand that AusNet has a reactive replacement program that would include the replacement of FOLCBs and only replace after the unit has failed. AusNet has considered continuing its reactive program concluding that this option did not mitigate the identified safety risk or reduce the likelihood or potential impact of catastrophic fires during extreme fire periods.[183]

525. We are satisfied that AusNet has reasonably determined the failure modes of existing FOLCBs, including by analysis and testing, and that the identified failure modes represent an elevated risk of failure and corresponding fire risk.

526. As we are not reviewing other parts of AusNet's proposed repex, we are not able to conclude that there are parts of the program that would not be impacted by the introduction of this proactive program, however we consider it is unlikely based on the specific targeted nature of the proposed program.

AusNet has made a reasonable estimate of its proposed program

527. We are satisfied that the elevated fire risk was not evident in the performance reporting prior to 2025, and that AusNet has an obligation to minimise safety risks as far as reasonably practicable, in accordance with regulatory requirements.

528. In addition to the reactive replacement option, AusNet considered and rejected a refurbishment option as not technically viable. The only technically viable solution is replacement. AusNet has developed an estimate of the population of FOLCBs in its highest risk areas, based on a combination of attributes in its network spatial program. We consider a targeted program focussed on the highest risk units is a reasonable approach.

181 AusNet – EDPR Revised Proposal 2027-31. Page 83.

182 ASD – AusNet – FOLCBs – 1Dec2025. Page 4.

183 ASD – AusNet – FOLCBs – 1Dec2025. Page 9.

Cost estimate is based on application of unit rates

529. AusNet states that the included labour and material costs are based on OMSA rates and assumes planned outages under normal conditions. On the basis that the rates are developed consistent with other OMSA rates, including by reference to historical average costs, we consider that this is a reasonable assumption.

4.5.5 Summary of findings

530. We consider that the proposed safety augex of $8.3 million for the fall arrest systems project, and safety repex of $8.0 million for the Codified FOLCB replacement projects are prudent and reasonable to be undertaken in the next RCP.

4.5.6 Alternate estimate

531. We consider the proposed capex of $16.3 million proposed by AusNet is reasonable.

4.6 REFCL compliance augex

4.6.1 Overview of AER's draft decision

532. In its draft decision, the AER was not satisfied that the proposed compliance and safety programs had been sufficiently justified.[184] In relation to the REFCL compliance program, the AER did not accept that the proposed costs were efficient:[185]

> *'We also consider AusNet's proposed REFCL compliance program to be reasonable in scope. However, we are not convinced that the proposed costs reflect efficient level expenditure. As a result, we have adopted EMCa's recommended unit rate and excluded both an unexplained cost item and the proposed risk allowance from the total expenditure.'*

533. We compare the expenditure proposed in the RP and the AER draft decision in Table 4.34.

Table 4.34: AER alternative estimate – REFCL driven augex ($m, FY26)

Projects	Proposal	AER draft decision
REFCL Driven Augmentation	76.5	63.2

Source: EMCa derived from AER, Attachment 2 – Capital expenditure | Draft decision – AusNet Services distribution determination 2026-31, table A.4

4.6.2 Overview of RRP

534. AusNet has proposed an increase to its REFCL compliance augex from $76.5 million to $147.9 million, being $84.7 million above the AER draft decision. In addition to re-proposing the RECFL driven augmentation project at a higher cost, AusNet has included two further RECL projects at Bairnsdale (BDL) and Lilydale (LDL) not originally included in its RP, as shown in Table 4.35.

184 AER, Attachment 2 – Capital expenditure | Draft decision – AusNet Services distribution determination 2026-31. Page 30.

185 AER, Attachment 2 – Capital expenditure | Draft decision – AusNet Services distribution determination 2026-31. Page 45.

Table 4.35: REFCL compliance augex projects ($m, June 2026)

Project	FY27	FY28	FY29	FY30	FY31	RCP total
REFCL Driven Augmentation (multiple sites)	-	4.6	25.8	27.5	49.4	**107.3**
REFCL Bairnsdale (BDL) augmentation (Delayed Project)	7.1	14.2	-	-	-	**21.3**
REFCL Lilydale (LDL) augmentation (WIP)	15.2	4.2	-	-	-	**19.3**
Total	**22.2**	**23.0**	**25.8**	**27.5**	**49.4**	**147.9**

Source: EMCa derived from ASD – AusNet Distribution – SCS Capex Model – 011225 - CONF

4.6.3 Assessment of REFCL Driven Augmentation

Updated information indicates that the cost and scope has changed since the RP

535. AusNet's RRP includes a revised business case that includes:[186]

- a higher estimate of capex due to increases in labour and material costs, and the scope of work has been refined through detailed scoping; and
- removal of the WYK24 Isolation Tx.

536. AusNet has proposed the same five remote REFCLs across four locations at Seymour, Wodonga TS 22kV, Woori Yallock, and Kinglake as included in its RP.

Revised scope of the program is reasonable

537. AusNet states that the revised capacitance forecast no longer requires the proposed isolation transformers at WYK24 that were included at the time of the RP and confirms that this has been removed from the revised program cost estimate.

538. On the basis that the AER considered the REFCL compliance program to be reasonable in scope, and that AusNet has revised the forecast capacitance to remove the proposed isolation transformers, we consider the program scope revision to be reasonable.

The estimated cost has materially increased

539. In Table 4.36 we compare the capex forecast included for the REFCL driven augex program between the RP and the RRP. Despite the reduction in scope discussed above, the program cost has increased by $30.8 million.

Table 4.36: Comparison of REFCL driven augmentation program ($m, real 2026)

REFCL Driven Augmentation	FY27	FY28	FY29	FY30	FY31	RCP Total
RP program	-	-	14.2	28.6	33.7	**76.5**
RRP program	-	4.6	25.8	27.5	49.4	**107.3**

Source: EMCa derived from RP and RRP Capex models

540. AusNet has provided an updated cost estimate for a remote REFCL based on an updated unit cost for a simple remote REFCL site and a complex remote REFCL site, assuming that the forecast capex includes three simple and two complex sites.[187] We understand that the unit cost developed for the simple site is based on removing some cost items from the complex site unit rate. We have reviewed this information.

186 ASD - AusNet - REFCL Driven Augmentation – 01122025. Page 2.

187 Installed across four locations at Seymour, Wodonga TS 22kV, Woori Yallock and Kinglake.

541. In Table 4.37 we compare the costs assumed in the RP and the RRP, based on the direct cost + P50 risk included in the respective cost estimates.

Table 4.37: REFCL unit cost assumptions

Cost category	RP Remote REFCL ($2024)	RRP simple remote REFCL ($2025)	RRP complex remote REFCL ($2025)
Design	[redacted]	[redacted]	[redacted]
Internal labour	[redacted]	[redacted]	[redacted]
Materials	[redacted]	[redacted]	[redacted]
Plant & Equipment	[redacted]		
Contracts	[redacted]	[redacted]	[redacted]
Risk allowance (uncertainty)	[redacted]	[redacted]	[redacted]
Total ($2024)	[redacted]		
Conversion factor to Real $2025	[redacted]		
Total ($2025)	[redacted]	[redacted]	[redacted]
Increase relative to RP	n/a	44%	59%

Source: EMCa analysis of ASD - AusNet - Direct Cost Summary - DD-0016722 - REFCL Driven Augmentation Generic Simple Site 01122025 - CONF and ASD - AusNet - Direct Cost Summary - DD-0016722 - REFCL Driven Augmentation Generic Complex Site_ 01122025 - CONF

542. We observe increases for most categories, with substantial increases associated with materials and contracts. On closer review of the cost estimate build-up, these increases are due to a combination of additional materials and higher cost of materials, higher contract scope, and higher contractor costs (indirect plus allowances).

543. We therefore considered other sources of cost information, to provide a comparison to the proposed costs.

AusNet claims a range of cost increases apply to REFCL sites

544. We asked AusNet to explain the basis for the increase in cost compared with the unit costs included in the RP, including drivers of the cost increases (for simple and complex sites). AusNet states that its remote REFCL cost build up includes a lot of items that would also be typically found at a ZSS making it appear to be the build up for a ZSS REFCL. According to AusNet,[188] this reflects an average cost increase of ~$7m per remote REFCL between the RP and RRP as shown in Table 4.38. The dollar basis is not provided in the response.

[188] AusNet - IR#079 AusNet Response - 13022026 – CONF.

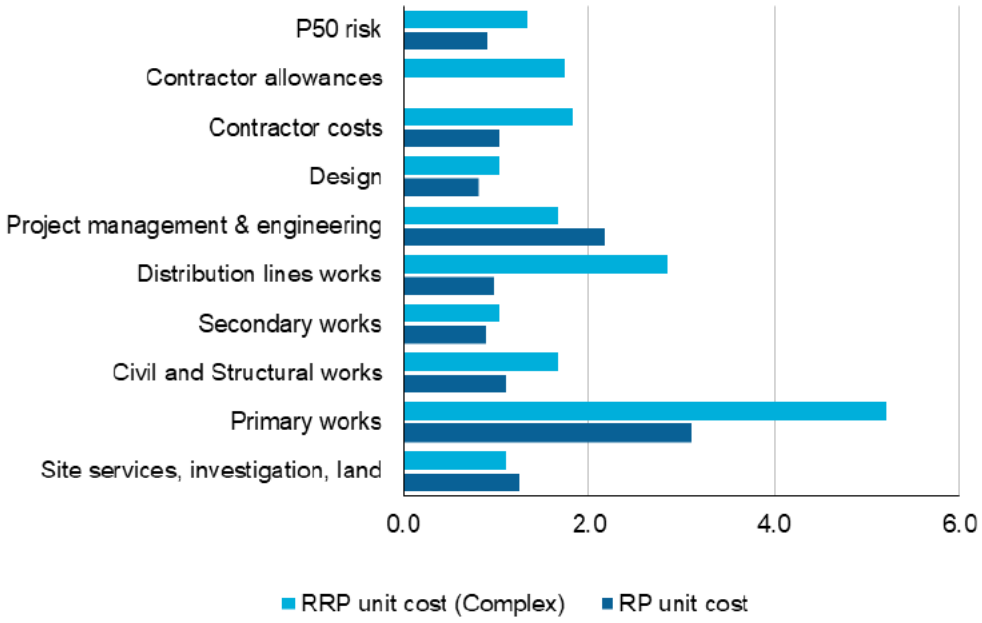
Table 4.38: AusNet claimed cost increases from RP to RRP

Adjustment	Total
Land Acquisition	[redacted]
Primary and Civil Works – increase of primary works, notable changes are for isolation transformer (revised material and installation costs), cabling underpriced in the IP, REFCL room underpriced in the IP, Neutral Bus Kiosk, earthworks including addition of noise enclosure, parking area, and additional cut & fill, and footings and structures brought in line with current benchmarks	[redacted]
Secondary – addition of feeder protection cabinet to scope, addition of DIC and router to scope	[redacted]
Lines – addition of extra lines works and addition of fibre path for protection and control	[redacted]
Outages – due to major augmentation to 22kV network	[redacted]
Design	[redacted]
CDP Incentive and Zinfra Adjustment	[redacted]
Total cost increases	[redacted]

Source: AusNet - IR#079 AusNet Response - 13022026 - CONF

545. We show a comparison by cost category in Figure 4.41, and with the exception of land, this broadly aligns with the information provided in Table 4.38.

Figure 4.41: Comparison of standard REFCL unit cost included in the RP and the RRP ($2024)



Source: EMCa analysis of bottom-up cost estimates

546. We asked AusNet to explain why the proposed unit costs are considered efficient, including by comparison with projects that AusNet has previously completed.

547. AusNet claims that the source of the [redacted] million ($2024) unit cost assumption included in the RP was based on a completed project at Violet Town in 2023 and, given the timing, would have been subject to upward cost pressures as discussed in Section 3. In response to our request for information, AusNet states that the Violet Town BN11 REFCL was completed at a cost of [redacted] million (nominal) and required an additional [redacted] million

(nominal) for a neutral bus kiosk which has become standard at AusNet.[189] Based on our review of the information provided by AusNet and our research, the addition of the neutral bus system installed in a ground mounted kiosk is typical of a REFCL installation.

548. In its response, AusNet confirmed that the cost assumptions for the Violet Town site were actual costs,[190] rather than an estimate. As actual costs, we consider that they represent a reasonable basis for a unit cost for a remote REFCL, subject to AusNet's justification of cost increases since the Violet town remote REFCL project was completed.

549. AusNet also states the following:

- The cost for Violet Town REFCL excluded design and land. However, as can be seen from Table 4.37, a design cost was included in the unit cost of [redacted] million ($2024) or [redacted] million escalated to $2026. Also, our review of the detailed cost estimate indicated land was similarly included.
- The Violet Town REFCL site was flat and had favourable ground conditions, which we infer from the provided images of the site. However, we do not consider that this is sufficient a reason to increase the unit cost for all sites.
- AusNet has updated its technical standards, which now require more robust protection and control systems, including the use of optical fibre communications. However, AusNet has not described the basis of these changes, and how they reflect an efficient cost. AusNet also refers to the inclusion of additional scope items in the Violet Town REFCL site.

The difference between the simple and complex sites is primarily driven by additional fibre optic costs

550. We reviewed the differences in unit costs between the simple and complex remote REFCLs, to help understand the basis of AusNet's assumptions, and found the highest cost differences related to:

- Additional fibre optic works (approx. [redacted] million)
- Additional benching, leveling, tip works and rock removal (approx. [redacted] million)
- Noise enclosure and design costs (approx. [redacted] million).

551. AusNet has not nominated which sites may require additional costs, if at all. Absent clear justification, we consider that a single unit cost should apply, that is based on the expected cost, and specific additional costs included for project specific requirements, and which AusNet has not done.

The unit cost closely approximates the cost of a substation REFCL, and includes large increases to cost allowances that have not been sufficiently justified

552. We observe that the proposed unit cost for a remote REFCL site was comparable to the cost for the BDL and LDL substation REFCLs of $19.1 million and $17.4 million respectively. We had expected to see a cost differential between the cost of a substation REFCL and remote REFCL, with the latter providing a lower cost alternative. Based on these comparisons, we consider this further supports our view that the proposed unit cost is higher than an efficient level.

553. We observe a number of cost allowances that suggest that a substation arrangement has been assumed, including for example the specification for a 200A arc suppression coil, which is typically included in the specification for a substation REFCL. We asked a further question to clarify why an arc suppression coil rating of 200A was included, when the business case included in the RP and the RRP nominated a rating of 80A for a remote

189 AusNet - IR#079 AusNet Response - 13022026 – CONF.

190 AusNet - IR079 clarification response - 20022026 – CONF.

REFCL, and which we had expected to see included for a remote REFCL unit. In its response, AusNet stated that:[191]

> *'The 200A coil is a standard product offered by the primary manufacturer who supplies this product. Maintaining this standard ensures interoperability with existing spares and related components. Although a smaller coil (e.g. 80A) would meet the technical requirements, it would constitute non-standard equipment in Ausnet and also for the two manufacturers who are capable of making these coils. Given the small number of remote REFCL installations, retaining a uniform coil specification remains the most cost effective and operationally efficient approach. Regardless of whether the 80A or 200A coils are installed, the remainder of the remote REFCL scope remains unchanged with no reduction to the primary plant requirements. The cost difference between the two sizes (80A and 200A) is expected to be marginal. We also note that a 200A coil allows for more network growth downstream of the remote REFCL than an 80A coil, which future proofs the installation.'*

554. Based on our review of the cost estimates provided by AusNet, a single 80A Trench Arc Suppression coil was included in the original cost estimate at [redacted] million ($2024) whereas a [redacted] coil was included in the RRP at [redacted] million ($2025). Whilst standardisation may provide additional benefits to AusNet, the benefits have not been provided for this upgrade, or associated equipment upgrades included in the proposed unit cost. The increase in rating for the coil, and possibly other items, are also not consistent with the scope in the business case included for the RP and RRP, nor the basis for the analysis of options.

555. Other cost items have similarly been increased, and we have not been provided with sufficient justification to support the extent of the cost increases that AusNet has proposed. Absent compelling justification, we consider that AusNet's cost estimate results in an over-estimate of the efficient cost.

The unit costs proposed by AusNet also do not compare favourably with other sources of unit costs for REFCLs

556. Recognising that it is not possible to undertake a direct comparison to other projects without taking account of the scope, we considered the average unit cost across four remote REFCL projects in Powercor's network for the next RCP.[192] This resulted in an average unit cost of approximately $13.4 million, which is materially lower than AusNet has proposed for the next RCP.

AusNet has not justified the proposed unit cost for its REFCL program

557. As discussed in Section 3, whilst we consider that, in general, the market environment has led to an increase in costs, the cost increases of 44% and 59% (as shown in Table 4.37) exceed the range of increases that have been observed for substation projects.

558. Whilst we accept also that the costs may differ between sites due to a range of factors, AusNet has not sufficiently justified the proposed increases to its unit costs, the basis for its unit costs for simple and complex sites, or the allocation of the unit costs to each of the proposed five sites.

559. Our review of costs both for AusNet's substation REFCL sites, and for Powercor's REFCL projects further indicate to us that the proposed cost is not reflective on an efficient cost, nor that the use of the unit cost assumptions that AusNet has proposed to calculate the capex requirement for the next RCP is reasonable.

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191 AusNet response to IR079 clarification response.

192 PAL BUS 3.11 – Bushfire mitigation forecast overview – Jan2025 – Public. Table 3. We identified sites that most closely aligned with the scope proposed by AusNet. The scope of some Powercor projects extended to additional works, including substation upgrades.

4.6.4 Assessment of REFCL Bairnsdale augmentation (delayed project)

560. AusNet has proposed $21.3 million for the installation of a substation REFCL at Bairnsdale (BDL) in the next RCP.[193] AusNet confirmed that the BDL REFCL project is entirely delayed from the current RCP to the next RCP.

Need and timing for the project is reasonable

561. In its RP, AusNet describes the REFCL project at BDL is required due to increasing capacitance growth that requires mitigation to ensure the network remains compliant. AusNet states that the expected growth means that the capacitive current limits of 144A on Bus 3 and 107A on Bus 4 provided by the existing REFCLs are no longer adequate.

562. We asked AusNet for an explanation of the timing for the BDL REFCL project, including demonstration of when the compliance levels are forecast to be exceeded. We sought the forecast capacitance versus capacity at these sites, including a copy of the forecasts, and the basis for the selected timing, including the reasons for delay from the current RCP.

563. From our review of AusNet's response,[194] we are satisfied that AusNet has reasonably determined the need and timing for the BDL REFCL project, based on its forecast increase in capacitance current. Specifically, the capacitance 'headroom' is forecast to be exceeded in 2025, at which time, without augmentation to reduce capacitance or increase the headroom, the REFCL becomes operationally challenging or impractical to maintain in service on total fire ban days.

564. We note that at the time of the RRP for the current RCP, the recommended option (Option 4) was the installation of a third REFCL at a cost of $14.1 million ($2021).[195] At the time, AusNet stated that the remote REFCL solution was currently under development.

Extended consultation contributed to delay of the project

565. AusNet describes its process for the review of options for BDL including the installation of remote REFCLs, over a substation REFCL. However, a remote REFCL is contingent on securing suitable land, and which AusNet states that, following completion of its investigations, no longer presented the least cost technically acceptable option. Due to the time required to complete the technical assessments of a suitable site, and engagement and negotiation with landowners, AusNet has proposed a third REFCL at BDL substation in the next RCP.

566. Based on the information provided to us, we accept that due to the inability to secure suitable land, further delay is not prudent and progressing the substation REFCL solution is reasonable.

We consider the proposed cost is overestimated, for the reasons discussed in Section 3

567. We consider that AusNet's updated cost estimate for the proposed scope of works to install a ZSS REFCL, with the exception of the combination of allowances that it has not sufficiently justified as discussed in Section 3. We take this view, recognising the cost uplift that has occurred, and that AusNet has described, and that there is a cost differential between undertaking a ZSS installed REFCL and a remote REFCL.

568. For the BDL site, we observe a significant increase in the contractor allowances, associated with CDP indirect costs which are not present in cost estimates we reviewed for other projects, and are in addition to the site establishment costs included in other cost allowances. We consider this provides further support of our view that AusNet has not sufficiently justified the extent of the cost allowances that it has proposed.

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193 ASD – AusNet - REFCL Bairnsdale (BDL)_Draft Project Assessment Report – 01122025.

194 AusNet - IR#069 -Response to EMCa questions 1-9 23012026 – CONF.

195 AusNet Services - Revised Regulatory Proposal - 2021-26 - AMS 20-407 - BDL REFCL Compliance Maintained Planning Report - December 2020. Page 4.

4.6.5 Assessment of REFCL Lilydale augmentation (WIP)

What AusNet has proposed

569. AusNet has proposed $19.3 million for the installation of a substation REFCL at Lilydale (LDL).[196]

570. We asked AusNet to confirm whether the entire LDL REFCL project was deferred to the next RCP (from the current RCP), or if not please indicate the expenditure by year for each project that shows expenditure to be incurred in the current RCP and next RCP.

571. AusNet stated that as a work in progress (WIP) project, the project has been commenced in the current RCP, as indicated in Table 4.39.

Table 4.39: REFCL Lilydale (LDL) augmentation (WIP) project cost – including OHs and CFCs ($m, June 2026)

Project	FY25	FY26	FY27	FY28	Project Total	RCP Total
Total	0.9	0.9	16.3	4.5	22.5	20.7

Source: AusNet's response to IR069

Need and timing for the project is reasonable

In its RP, AusNet describes that the REFCL project at LDL is required due to increasing capacitance growth that requires mitigation to ensure the network remains compliant. Current capacitive demand exceeds the capacitive current limit of 192 amperes at LDL, which triggered this project in the current RCP.

572. We asked AusNet for an explanation of the timing for the BDL REFCL project, including demonstration of when the compliance levels are forecast to be exceeded. We sought the forecast capacitance versus capacity at these sites, including a copy of the forecasts, and the basis for the selected timing, including the reasons for delay from the current RCP.

573. From our review of AusNet's response,[197] we are satisfied that AusNet has reasonably determined the need and timing for the LDL REFCL project, based on its forecast increase in capacitance current.

574. We note that AusNet's preferred solution at the time that AusNet submitted its RRP for the current RCP was network reconfiguration, undergrounding, and installation of an isolation transformer at a cost of [redacted] million ($2021).[198] At the time, AusNet stated that the remote REFCL solution was currently under development, and the substation REFCL was determined to be non-credible due to the presence of other more cost effective and easily deployed options.

Extended consultation contributed to delay of the project

575. In response to our information request,[199] AusNet states that its preferred option for reducing capacitance on the LDL REFCL network was the installation of two 5 MVA isolation transformers. However, progressing this option is contingent on securing suitable land, and which AusNet states that following completion of its investigations no longer presented the least cost technically acceptable option. Specifically, AusNet refers to progressing negotiations with Parks Victoria which subsequently did not proceed, and whilst other options were progressed, AusNet was not able to secure suitable private land.

196 ASD - AusNet - DD-0014775_REFCL_LDL_Augmentation _Business_Case_Signed - 25112024 – CONF.

197 AusNet - IR#069 -Response to EMCa questions 1-9 23012026 – CONF.

198 AusNet Services - Revised Regulatory Proposal - 2021-26 - AMS 20-403 - LDL REFCL Compliance Maintained Planning Report - December 2020. Page 4.

199 AusNet - IR#069 -Response to EMCa questions 1-9 23012026 – CONF.

576. A further option was investigated (comprising load transfer and new underground cable) based on revised capacitance forecasts, however this was deemed to require a higher cost and was not a sustainable solution.

577. Due to the time required to complete technical assessments of a suitable site, engagement and negotiation with landowners and review of alternate options, AusNet has proposed a third REFCL at LDL substation to be completed in the next RCP as the least cost technically acceptable solution. This is a WIP project, having commenced in FY25.

578. We accept that due to the inability to secure suitable land, further delay is not prudent and progressing the substation REFCL solution is reasonable.

Proposed cost is overestimated, for the reasons discussed in Section 3

579. Similar to our review of the BDL REFCL, for the same reasons, we consider that AusNet's updated cost estimate for the increase in scope is reasonable, with the exception of the combination of allowances that it has not sufficiently justified as discussed in Section 3.

4.6.6 Summary of findings

Our initial review accepted the need for the REFCL driven augmentation program

580. In our initial review, AusNet had proposed the installation of five remote REFCL units to manage increasing capacitance levels in its network. Based on the information before us at that time, we considered that the solution was reasonable, however we found evidence of an over-estimate of the proposed cost.

Updated information supports our initial view, that the REFCL driven program is reasonable

581. From our assessment of its RRP, AusNet has reduced the number of projects it expects to require to manage the forecast capacitance exceedance across its REFCL sites (excluding projects from the current RCP), specifically removing the scope for isolation transformers at the WYK site. We accept that this is a reasonable response to changing needs of the network.

582. However, AusNet has also significantly increased the unit cost that it has assumed for this program from that provided in its RP. Based on the information provide to us, AusNet has not demonstrated that its costs are efficient.

REFCL projects at BDL and LDL are delayed from the current RCP

583. Following submission of its RRP for the current RCP, AusNet reviewed the capacitance forecasts and its options for ensuring ongoing compliance for its REFCL protected networks. The lower cost preferred options were contingent on securing suitable land, and following delays, installation of the REFCL at the substation sites was selected as the least cost technically acceptable solution.

584. Based on the information provided to us, we accept that due to the inability to secure suitable land, further delay is not prudent and progressing the substation REFCL solution at BDL and LDL is reasonable.

Proposed cost of BDL and LDL REFCL projects are overestimated, for the reasons discussed in Section 3

585. We consider that AusNet's updated cost estimate for the increase in scope is reasonable, with the exception of the combination of allowances that it has not sufficiently justified as discussed in Section 3.

4.6.7 Alternative estimate

REFCL program

The forecast capex requirements are higher than was included in AusNet's RP

586. Based on the information provided by AusNet, we consider that the capex included in the RP for the REFCL driven augex program, after adjustment for removal of the scope for isolation transformers, is not likely to be sufficient for AusNet to deliver a REFCL program that meets its prudent and efficient requirements.

A reasonable unit cost is lower than AusNet has proposed

587. Our analysis indicates that a unit cost that is comparable to the unit cost included in the RP is likely to compare favourably to other sites and to Powercor's REFCL program. As discussed in Section 3, we consider that AusNet has experienced an increase to its expected costs since the preparation of the RP program, accounting for market based costs and scope maturity. However, AusNet has not justified the level of increases that it has proposed.

588. For the purpose of determining a reasonable alternative forecast, we consider that the unit cost for a Remote REFCL at a simple site reduced by approximately 20% is a reasonable estimate. We arrive at this view, based on our assessment that, the alternate estimate of unit cost:

-
- closely approximates the unit cost included in the RP increased by 20% to reflect cost increases and scope maturity, aligned with the level of cost increases described in Section 3; and
- provides a reasonable cost differential to the cost of a substation REFCL.

BDL and LDL REFCL projects

It is reasonable to allow for some cost increases, however we consider that the revised costs are upwardly biased.

589. AusNet has developed revised cost estimates for inclusion in its RRP, and we consider that the combination of cost allowances results in an over-estimate of the efficient cost as described in Section 3.2.4. We have estimated the impact of the issues that we identified in the same way as described in Section 4.3.12 and which we consider apply to the DBDL and LDL projects.

Overall alternative forecast

Our proposed alternative forecast is $25.9 million (or 18%) less than AusNet has proposed

590. The net result of applying the adjustments described above is to propose an alternative forecast of $122.0 million, which compares with AusNet's revised proposal of $147.9 million.

591. While we have 'built up' our alternative forecast from the components of the program as AusNet has proposed, we consider that an appropriate interpretation of this forecast is that in aggregate, the proposed capex provides a reasonable overall allowance to enable AusNet to address the identified issues.

4.7 Compliance augex

4.7.1 Overview of AER's draft decision

592. The Voltage Regulator Relay Replacement project that we have been asked to review was not included in AusNet's RP, and therefore not considered by the AER in its draft decision for the next RCP.

4.7.2 Overview of RRP

593. AusNet has proposed a Voltage Regulator Relay Replacement (WIP) at a cost of $2.9 million, which it describes as originally planned for the current RCP. Given the delay in delivery of this project, AusNet expects that some costs will carry over (in full or part) to the next RCP as shown in Table 4.40.

Table 4.40: Compliance projects ($m, June 2026)

Project	FY27	FY28	FY29	FY30	FY31	RCP total
Voltage Regulator Relay Replacement (WIP)	**2.9**	**-**	**-**	**-**	**-**	2.9

Source: EMCa derived from ASD – AusNet Distribution – SCS Capex Model – 011225 - CONF

4.7.3 Assessment of Voltage Regulator Relay Replacement (WIP)

594. AusNet has provided a copy of the original business case[200] for replacing voltage regulating relays (VRR) on existing transformers with compatible modern equivalents. The replacement VRRs will allow reverse power flow compensation at ZSSs to control voltage within threshold limits. [redacted] The business case indicates a cost of $3.0 million (nominal, including CFCs and OHs), and AusNet refers to the project forming part of the approved capex allowance for the current RCP.

595. The project was due for completion by 30 June 2024, however the project has been delayed.

596. AusNet has provided two project change requests (PCRs):

- PCR01,[201] included an extension of time to 30 September 2025, increase in the number of inline voltage regulating relay sites, descoping Traralgon ZSS works and replacing RTU at Watsonia ZSS; the changes resulted in an increase of [redacted] million (nominal, including CFCs and OHs), increasing the total approved capex at completion to [redacted] million (nominal, including CFCs and OHs).
- PCR02,[202] included an extension of time for AIS to 30 September 2026. The PCR indicated a re-profiling of the capex, but no change to the project approval.

597. However, we observe that the capex proposed for the next RCP appears to exceed the value indicated in PCR02, being the budget of [redacted] million minus the actuals to August 2025 of [redacted] million as stated in the PCR. We asked AusNet to explain the basis for the proposed capex in the next RCP, including the remaining scope and reason for any delays.

598. In its response,[203] AusNet provided an updated actuals to date and forecast as shown in Table 4.41. AusNet stated that it had found misalignment with the forecasts, which has been corrected in the updated figures.

200 ASD - AusNet - DD-0011611 Voltage Regulator Relay Replacements Business Case (BC) - 21112022 – CONF.

201 ASD - AusNet - DD-0011611 Voltage Regulator Relay Replacements PCR01 - 10022025 – CONF.

202 ASD - AusNet - DD-0011611 Voltage Regulator Relay Replacements PCR02 - 11092025 – CONF.

203 AusNet response to IR069.

Table 4.41: Voltage Regulator Relay Replacement project cost ($m, nominal)

	FY22 Actual	FY23 Actual	FY24 Actual	FY25 Actual	FY26 Estimate	FY27 Forecast	Project Total	Next RCP total
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Source: AusNet's response to IR#069

599. AusNet states that an identified safety issue, and accompanying work restriction on access to and work on DS2 (regulator) tap changers resulted in the delay to the project. AusNet estimates that the required maintenance work will be completed by mid this year, at which time the project is expected to resume.

600. The remaining scope relates to additional equipment purchases and onsite construction at all sites, as no construction has commenced.

601. We asked AusNet to confirm the updated forecast in $2026, and in response, AusNet confirmed that when converted to $2026, to align with the capex model, the updated forecast for the next RCP is $2.15 million (or $2.2 million rounded).

4.7.4 Summary of findings

602. Based on the information provided by AusNet, this project has been delayed due to an identified safety issue, and a pause to the project to address the risk was reasonable, requiring completion of the project in the next RCP.

603. Based on our understanding that the project cost has been formed in a similar way to other projects we have reviewed, including the application of a P50 risk allowance, we consider that the cost estimate is similarly over-estimated.

604. The remaining work and updated cost of $2.2 million will be incurred in the first year of the next RCP, and with the exception of the over-estimated cost allowances, the project is reasonable.

4.7.5 Alternative forecast

Our proposed alternative forecast is $1.9 million based on AusNet's updated forecast

605. The net result of applying the adjustments described above is to propose an alternative forecast of $1.9 million, which compares with AusNet's initial proposal of $2.9 million.

5 SUMMARY IMPLICATIONS FOR THE ASPECTS OF EXPENDITURE WE HAVE BEEN ASKED TO REVIEW

AER asked us to provide advice on an alternative estimate for the projects that we have reviewed, given that we consider that AusNet's proposed expenditure does not fully meet the NER requirements.

We have developed a bottom-up central alternative estimate that is 24% less than AusNet has proposed, once we take account of the matters that we describe in our assessment. Based on this and broad consideration of information and forecasting uncertainties, we consider that a reasonable alternative estimate lies between 20% and 30% less than AusNet has proposed.

5.1 Implications for forecast capex

AER has asked us to advise on an alternative estimate, to the extent we consider that AusNet's proposal does not meet the requirements of the NER

606. Our review comprises 28 projects totalling $776.6 million, primarily augex with inclusion of a safety repex project.

607. As requested by the AER, we have developed a central estimate of alternative forecasts consistent with our findings in Sections 3 and 4, based on the new information that AusNet has provided in its RRP and its responses to our information requests.

5.2 How we have built up our alternate estimate

We have built up an alternative estimate based on consideration of three main groups of issues

608. The central estimate of our alternate estimate is based on three main groups of issues:

- For the LV augex project, we consider that AusNet's claimed 'economic modelling' in response to its claimed increasing thermal overload risks is not fit for purpose:
  - For DSS, we consider that AusNet's expenditure in FY26 provides the only reasonable proxy (of the information that AusNet has provided).
  - For the reasons described in section 4.4.6, we consider that AusNet has not justified the SWER upgrades that it proposes and has provided no information that would justify inclusion of an allowance for such a program.
- Projects for which the option or prudent timing is different to that which AusNet has proposed, including:
  - For the Augment East Gippsland 66kV Loop (MWTS–TGN–MFA lines) project, a deferral of one year due to derivation of economic timing for the work as FY31.
  - For the new 22kV distribution feeder (WGL31) and New Switchboard at WGL ZSS project we consider that a modified version of AusNet's Option 3 which includes establishing a BESS in the next RCP is the prudent approach.
- Projects for which the cost estimates that AusNet has included in its RRP are higher than an efficient cost, including:

- We found evidence that the over-estimation applies to the majority of the proposed augex projects.
- Specifically, for the REFCL driven augex, AusNet has not justified the increase to the unit cost that AusNet has proposed. We draw from a number of sources to develop an alternate estimate of the unit cost, and which apply to the proposed program of work.

609. In addition, we have accepted the safety and summer and winter network readiness projects. AusNet has proposed a small change for the compliance project, arising from a re-forecast of the proposed capex for FY27, for which we have included.

5.3 Alternate estimate

We summarise our alternative estimate grouped by driver and according to the issues that we found

610. In Table 5.1, we present the aggregate of the alternate estimates derived from our assessment as the basis for our central estimate.

Table 5.1: EMCa alternate estimate to proposed augex by project for next RCP ($m, real 2026)

	FY27	FY28	FY29	FY30	FY31	RCP total
Proposed augex (for selected projects)	195.6	196.9	164.7	125.1	94.3	776.6
Demand-driven augex (excl LV augex)						
Projects that we accept	1.4	1.4	1.4	1.4	1.4	7.0
Projects for which we have adopted a different solution or timing	-	16.0	17.3	12.5	4.0	49.8
Projects for which we have adopted a different cost basis or unit cost	109.0	108.3	72.1	52.2	22.6	364.3
LV augex						
Projects for which we have adopted a different solution or timing	7.1	6.5	3.9	4.0	4.9	26.4
Safety						
Projects that we accept	3.2	3.1	3.1	3.2	3.6	16.3
REFCL compliance						
Projects for which we have adopted a different cost basis or unit cost	19.8	20.0	20.6	22.0	39.5	122.0
Compliance						
Projects for which we have adopted a different cost basis or unit cost	1.9	-	-	-	-	1.9
EMCa alternative estimate (for selected projects)	**142.4**	**155.3**	**118.5**	**95.3**	**76.1**	**587.6**
Variance	-53.2	-41.6	-46.2	-29.7	-18.2	-188.9
Indicative adjustment (central estimate)						**-24%**

Source: EMCa analysis

For the projects we have been asked to review, our central alternative estimate for a reasonable forecast is in aggregate 24% less than AusNet has proposed, with a range from 20% to 30% less than AusNet has proposed

611. We propose adjustments for the issues that we have identified, and which lead us to a central estimate of the required capex for the selected augex projects that we have been asked to review as approximately 24% lower than AusNet has proposed.

612. Whilst we have 'built up' our alternative estimate from the components of the program as AusNet has proposed, we consider that an appropriate interpretation of this alternative estimate is that in aggregate, the proposed capex provides a reasonable overall allowance to enable AusNet to address the identified issues.

613. We suggest that this is more accurately represented as a range of between 20% to 30% lower than AusNet has proposed, or between $543.6 million and $621.3 million for the next RCP. We consider that this range is appropriate on the basis that:

- we have not been asked to consider the total capex portfolio, or total augex forecast; and
- it allows for additional factors to be taken into account by the AER in setting a reasonable capex allowance for the next RCP, including those that apply to the prioritisation and delivery of the capital portfolio.