Final Decision

Ergon Energy Electricity Distribution Determination 2025 to 2030

(1 July 2025 to 30 June 2030)

Attachment 5

Capital Expenditure

April 2025

AUSTRALIAN ENERGY REGULATOR

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AER reference: AER213702

Amendment record.

Version	Date	Pages
1	30 April 2025	35

List of attachments

This attachment forms part of the Australian Energy Regulator's (AER's) final decision on the distribution determination that will apply to Ergon Energy for the 2025–30 period. It should be read with all other parts of the final decision.

As a number of issues were settled at the draft decision stage or required only minor updates, we have not prepared all attachments. Where an attachment has not been prepared, our draft decision reasons form part of this final decision. The final decision attachments have been numbered consistently with the equivalent attachments to our draft decision.

The final decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

Attachment 13 – Classification of services

Attachment 14 – Control mechanisms

Attachment 16 – Alternative control services

Attachment 18 – Connection policy

Attachment 19 – Tariff structure statement

Attachment 20 – Metering services

Contents

5 Capital expenditure

Capital expenditure (capex) refers to the money required to build, maintain or improve the physical assets needed to provide standard control services (SCS).[1] Generally, these assets have long lives and a distributor will recover capex from customers over several regulatory control periods. A distributor's capex forecast contributes to the return of and return on capital building blocks that form part of its total revenue requirement.

Under the regulatory framework, a distributor must include a total forecast capex that it considers is required to meet or manage expected demand, comply with all applicable regulatory obligations, maintain the safety, reliability, quality, and security of its network and contribute to achieving emissions reduction targets (the capex objectives).[2]

We must decide whether or not we are satisfied that this forecast reasonably reflects prudent and efficient costs and a realistic expectation of future demand and cost inputs (the capex criteria).[3] We must make our decision in a manner that will, or is likely to, deliver efficient outcomes in terms of the price, quality, safety, reliability and security of supply, and contribute to achieving targets for reducing Australia's greenhouse gas emissions, for the benefit consumers in the long term (as required under the National Electricity Objective).[4]

The *AER capital expenditure assessment outline* explains our and distributors' obligations under the National Electricity Law and Rules (NEL and NER) in more detail.[5] It also describes the techniques we use to assess a distributor's capex proposal against the capex criteria and objectives. Where relevant we also assess capex associated with emissions reduction proposals taking into account our *Guidance on amended National Electricity Objectives*.[6]

5.1 Total capex framework

We analyse and assess capex drivers, programs and projects to inform our view on a total capex forecast. However, we do not determine forecasts for individual capex drivers or determine which programs or projects a distributor should or should not undertake. This is consistent with our *ex-ante* incentive-based regulatory framework and is referred to as the 'capex bucket'.

Once the *ex-ante* capex forecast is established, there is an incentive for distributors to provide services at the lowest possible cost, because the actual costs of providing services will determine their returns in the short term. If distributors reduce their costs, the savings are shared with consumers in future regulatory control periods. This incentive-based framework

1 These are services that form the basic charge for use of the distribution system.

2 NER, cl. 6.5.7(a).

3 NER, cl. 6.5.7(c).

4 NEL, ss. 7, 16(1)(a).

5 AER, *Capex assessment outline for electricity distribution determinations*, February 2020.

6 AER, *Guidance on amended National Energy Objectives*, September 2023.

provides distributors with the flexibility to prioritise their capex program given their circumstances and due to changes in information and technology.

Distributors may need to undertake programs or projects that they did not anticipate during the revenue determination. Distributors also may not need to complete some of the programs or projects proposed if circumstances change, these are decisions for the distributor to make. We consider a prudent and efficient distributor would consider the changing environment throughout the regulatory control period and make decisions accordingly.

Importantly, our decision on total capex does not limit a distributor's actual spending. We set the forecast at a level where the distributor has a reasonable opportunity to recover its efficient costs.

5.2 Assessment approach

We provide guidance on our assessment approach in several documents, including the following which are of relevance to this decision:

- *Expenditure Forecast Assessment Guidelines*[7]
- *Regulatory Investment Test for Distribution and Transmission guidelines*[8]
- *Asset Replacement Industry Note*[9]
- *Information and Communication Technologies (ICT) Guidance Note*[10]
- *Distributed Energy Resources Integration Expenditure Guidance Note*[11]
- *Guidance Note on Network Resilience*[12]
- *Guidance on amended National Energy Objectives.*[13]

We also had regard to the guiding principles in the AER's *Better Resets Handbook – Towards consumer centric proposals* which encourages networks to develop high quality, well-justified proposals that genuinely reflect consumers' preferences.[14]

Our final decision has been based on the information before us, which includes:

- the distributor's regulatory proposal and accompanying documents and models
- the distributor's responses to our information requests
- stakeholder comments in response to our Issues Paper, our draft decision and Ergon Energy's revised proposal

7 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, October 2024.

8 AER, *Regulatory Investment Test (RIT) application guidelines*, 21 November 2024.

9 AER, *Industry practice application note for asset replacement planning*, January 2019.

10 AER, *Guidance note - Non-network ICT capex assessment approach*, 28 November 2019.

11 AER, *Distributed energy resources integration expenditure guidance note*, June 2022.

12 AER, *A guidance note on network resilience*, April 2022.

13 AER, *Guidance on amended National Energy Objectives*, September 2023.

14 AER, *Better Resets Handbook – Towards consumer-centric network proposals*, December 2021.

- technical review and advice from our consultant's reports. We engaged EMCa in March 2024 to assist us in reviewing certain aspects of Ergon Energy and Energex's capex proposals. These include Ergon Energy's overspend in replacement expenditure (repex) and forecast repex, aspects of Ergon Energy and Energex's forecast augmentation expenditure (augex), and Ergon Energy and Energex's forecast for cyber security. EMCa's report was released with our draft decision.

5.3 Final decision

Our final decision is to not accept Ergon Energy's proposed total forecast capex of $5,011.4 million ($2024–25) because we are not satisfied that it reasonably reflects the capex criteria (in particular, we are not satisfied that it reasonably reflects the prudent and efficient costs required to meet the capex objectives). Our substitute forecast is $4,410.7 million, which is 12.0% below Ergon Energy's forecast.

We consider this forecast will sufficiently allow a prudent and efficient service provider in Ergon Energy's circumstances to meet the capex objectives. Table 5.1 outlines our substitute estimate of forecast capex and compares this to Ergon Energy's proposed forecast capex.

Table 5.1 AER's final decision on Ergon Energy's total net capex forecast ($ million, $2024–25)

	2025-26	2026-27	2027-28	2028-29	2029-30	Total
Ergon Energy's revised proposal	960.5	979.8	992.9	1021.6	1056.5	5011.4
AER's final decision	851.6	858.3	871.8	890.2	938.9	4410.7
Difference ($)	**-109.0**	**-121.5**	**-121.2**	**-131.5**	**-117.6**	**-600.8**
Difference (%)	**-11.3%**	**-12.4%**	**-12.2%**	**-12.9%**	**-11.1%**	**-12.0%**

Source: Ergon Energy's initial proposal and AER analysis. Numbers may not sum due to rounding.

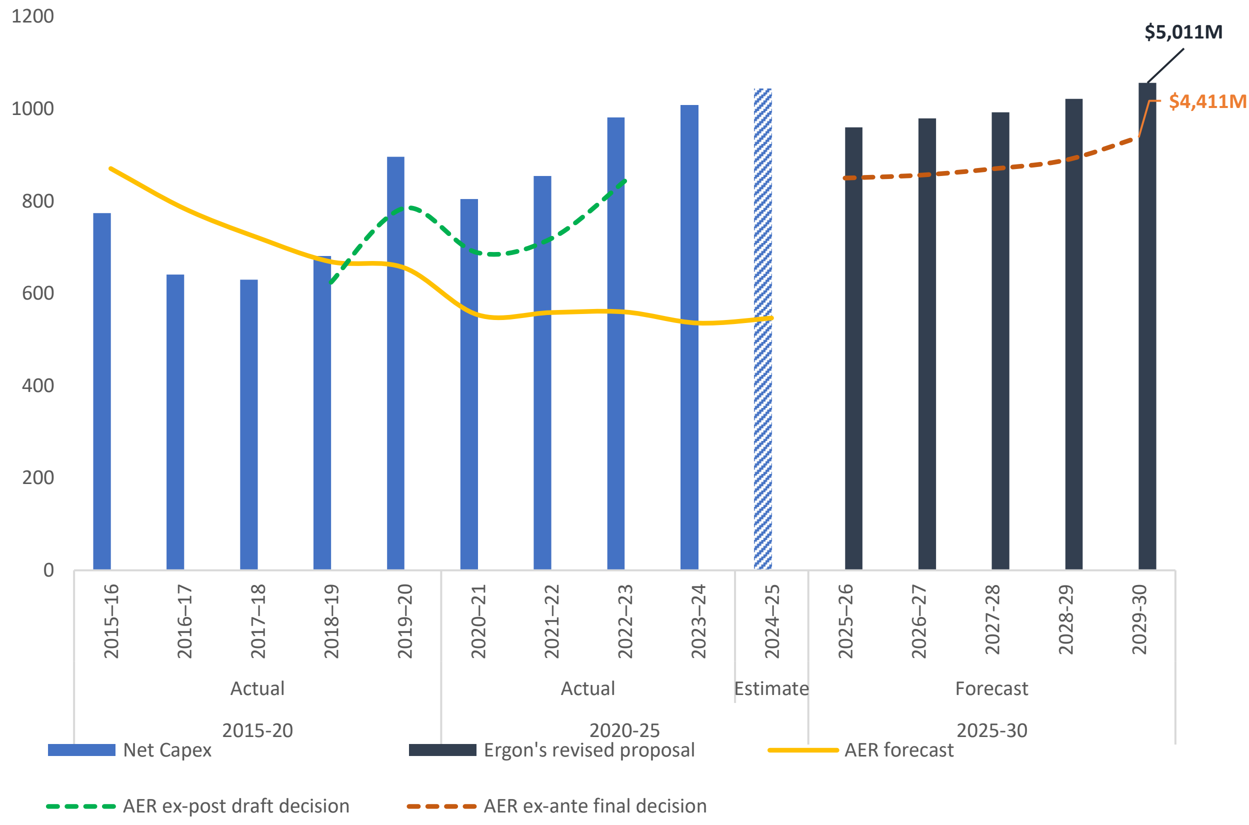
5.4 Ergon Energy's revised proposal

Ergon Energy's proposal forecasts $5,011.4 million ($2024–25) capex over the 2025–30 regulatory control period. This is 12.2% lower than its initial proposal.

Its revised proposal accepts the lower forecasts in the AER's draft decision on ICT capex, and property capex. Ergon Energy also submitted revised lower forecasts in repex, augex, fleet, network resilience, and capitalised overheads.

Figure 5.1 below shows Ergon Energy's historical capex trend, its proposed forecast for the 2025–30 regulatory control period, and our final decision.

Figure 5.1 Ergon Energy capex profile ($ million, $2024–25)



Source: Ergon Energy's revised proposal and AER analysis. Numbers may not sum due to rounding.
Note: Capex is net of asset disposals and capital contributions.

As can be seen in Figure 5.1, the AER's ex-post review reduced the value of Ergon Energy's capex overspend in the ex-post period (2018–23 period) allowed to be rolled into the opening regulatory asset base.[15] Ergon Energy has not contested this draft decision position due to affordability concerns.[16] We also observe that the estimates in the last 2 years of the current period are higher than other years in the current period. This would suggest that another ex-post review is a possibility in the next determination.

5.5 Reasons for final decision on Ergon Energy's forecast capex for 2025–30

We are satisfied that our alternative forecast of total capex of $4,410.7 million is reasonable and sufficient for Ergon Energy to achieve the capex objectives, especially to maintain the safety and reliability of its network. In coming to our decision, we have been cognisant of the safety and reliability risks faced by Ergon Energy, and therefore have accepted Ergon Energy's volume forecasts for a number of programs where safety and reliability risks have been the primary driver. For instance, we have accepted Ergon Energy's clearance volume

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15 An alternative ex-post capex overspend amount of $598 million (a 50% reduction) has been rolled into the opening regulatory asset base.

16 Ergon Energy, *Repex 2025-2030: Repex Ex-Post & Ex-Ante Narrative*, 18 November 2024, p 7.

forecasts and its low density 3kN poles volumes which provides funding for it to address the safety and reliability risks associated with these assets. However, we have not accepted Ergon Energy's forecast where we have not been provided evidence that demonstrates an overall benefit to consumers. For instance, we have not accepted expenditure for inefficient opportunistic replacement, as it results in the unnecessary replacement of assets.

In making this final decision, we have assessed all information before us including new and additional information Ergon Energy provided in response to our draft decision. As noted in our draft decision, our position on Ergon Energy's forecast capex was a placeholder given the major information gaps in its proposal, especially in repex which is a key driver of its capex forecast for 2025-30. We acknowledge the efforts Ergon Energy has made to address these gaps including extensive engagement with us post release of our draft decision, which included AER staff attending face-to-face meetings over several days to work through the information it had available.

Ergon Energy's new and additional supporting information has allowed us to assess Ergon Energy's proposal afresh, and to undertake deeper analysis to better understand the basis of Ergon Energy's forecast. This has allowed us to accept Ergon Energy's forecast expenditure in full in some cases where we have been satisfied that this information supports a prudent and efficient forecast; namely for Ergon Energy's revised forecast for fleet, network resilience and its augex-related secondary systems program.

In other cases, we were not provided with sufficient evidence to support a prudent and efficient forecast. This was the case for Ergon Energy's repex forecast and aspects of its augex forecast. For repex, our final decision is a higher forecast relative to the draft decision ($97.0 million more than the draft decision). The higher repex forecast in the final decision is reflective of our finding in some cases of Ergon Energy's supporting information justifying more capex (in Ergon Energy's pole and clearance to ground (CTG)/clearance to structure (CTS) programs). But, in other cases, we found the new and additional information reaffirmed our concerns which supported maintaining our draft decision position (for pole top structure, conductor and repex-related secondary system programs). Where we have derived alternative forecasts, these have been based on a bottom-up assessment which addresses Ergon Energy's concerns about the draft decision alternative forecast being based on benchmarking against Essential Energy's network.

There were a number of key findings from our assessment. We encourage Ergon Energy to consider these areas of improvement for future processes. These findings are:

- *Ergon Energy's systemic practice of retrospectively applying new standards to its existing assets*. Ergon Energy is forecasting to continue this practice in its replacement of poles, conductors, and CTG/CTS. The retrospective application of new standards to existing assets is not consistent with good industry practice and results in more assets being replaced than is prudent and efficient. The Consumer Challenge Panel's (CCP30) submission also raised concerns about this inefficient practice.
- *Inefficient opportunistic replacement.* We have accepted opportunistic replacement where it is prudent and efficient, such as the replacement of pole top structures and service lines when replacing poles. However, Ergon Energy did not provide sufficient evidence to demonstrate that the practice of replacing these assets when replacing

conductors or addressing clearance defects is consistent with prudent and efficient decision-making.

- *Underlying data issues and limited supporting quantitative analysis*. We found some of Ergon Energy's underlying data, such as its historical pole data that its forecast is based on, to be unreliable because of data inaccuracies and inconsistencies. Also, we found a systemic overstatement of benefits embedded in its cost-benefit analyses.
- *Critical new and additional information was provided by Ergon Energy in its revised proposal, when this is typically provided as part of a Network Service Provider's (Provider's) initial proposal.* For instance, Ergon Energy's concerns and details about its low density poles was only revealed in its revised proposal. This does not give stakeholders the opportunity to thoroughly review and provide feedback.
- *Concerns that Ergon Energy's revised proposal did not genuinely reflect its customers' preferences.* We note submissions from EQL's Reset Reference Group (RRG) and the CCP30 which observed that Ergon Energy was biased in the manner that it presented the AER's draft decision. In particular, the CCP30 notes that:[17]

  > '…in the Customer Panel Workshops in October, following the draft decision, the Ergon Energy (and Energex) presentations were tilted in the direction of supporting Ergon Energy and Energex's position, with an undercurrent that any reductions in funding by the AER would most likely result in reduced service quality to customers and heightened safety risks. As a result of this one-sided view, the feedback from the Customer Panel and Focus Group workshops heavily favoured the Ergon position.'

Table 5.2 sets out our final decision for Ergon Energy by capex category.

Table 5.2 AER's final decision by capex category ($ million, $2024–25)

Category	Ergon Energy's Revised Proposal	AER Final Decision
Replacement	2,449.8	1,941.3
Network resilience	34.6	34.6
Augex	489.2	432.9
Connections	321.3	321.3
Fleet	222.3	222.3
Property	170.2	170.2
Cyber security	53.3	53.3
ICT	208.4	208.4

17 Consumer Challenge Panel, *Advice to the AER regarding the Draft Decision and Revised Regulatory Proposal 2025-30*, January 2025, p.41.

Category	Ergon Energy's Revised Proposal	AER Final Decision
CER integration	63.0	63.0
Other non-network	31.6	31.6
Capitalised overheads	1,009.7	966.8
Total capex (excluding capital contributions)	**5,053.4**	**4,445.7**
Less Disposals	-41.9	-41.9
Less Modelling adjustments	n/a	6.9
Net capex	**5,011.4**	**4,410.7**

Source: Ergon Energy and AER analysis. Numbers may not sum due to rounding.
Note: We recategorised capex from Ergon Energy's revised proposal to align with how we assessed each category. We recategorised $7.9 million of repex, $16.1 million of augex, and $29.4 million of ICT to cyber security. We recategorised $34.6 million of augex to resilience. Consistent with our draft decision, we also recategorised $164.8 million in clearance to ground/structure capex from augex to repex.

Table 5.3 summarises, and Appendix A provides further details on, the reasons for not accepting Ergon Energy's forecast, by capex driver. This reflects the way we have assessed Ergon Energy's total capex forecast. Table 5.3 also summaries our reasons for accepting capex categories in this final decision and our draft decision.

Our findings on each capex driver are part of our broader analysis and should not be considered in isolation. We do not approve an amount of forecast expenditure for each individual capex driver or project/program. However, we use our findings on the different capex drivers to assess a regulated business' proposal as a whole and arrive at a substitute estimate for total capex where necessary. Our decision on total capex does not limit a regulated business' actual spending.

Table 5.3 Summary of our findings and reasons, by capex driver

Driver	Findings and reasons
Repex	We have not included Ergon Energy's forecast for repex of $2,449.8 million ($2024-25) in the total capex forecast. Our alternative forecast is $1941.3 million ($2024-25), which is 20.8% lower than Ergon Energy's forecast. We acknowledge the efforts Ergon Energy has made to address information gaps noted in our draft decision. Ergon Energy's new and additional supporting information has allowed us to assess Ergon Energy's proposal afresh, and to undertake deeper analysis to better understand the basis of Ergon Energy's forecast. Our final decision is a higher repex forecast relative to the draft decision ($97 million more in this final decision). The higher repex forecast in this final decision is reflective of our finding in some cases of Ergon Energy's supporting information justifying more capex (in Ergon Energy's pole CTG/CTS programs). But, in other cases, we found the new and additional information supported maintaining our draft decision position (for pole top structure, conductor and repex-related secondary system programs). Where we have derived alternative forecasts, these have been based on a bottom-

Driver	Findings and reasons
	up assessment which addresses Ergon Energy’s concerns about the draft decision alternative forecast being based on benchmarking against Essential Energy’s network. This is discussed further in Appendix A.
Augex	We have not included Ergon Energy’s forecast augmentation expenditure (augex) of $489.2 million ($2024–25) in the total capex forecast. Our alternate forecast is $432.9 million ($2024–25), which is 11.5% lower than Ergon Energy’s forecast. We found most aspects of Ergon Energy’s augex to be reasonable and accepted its revised grid communications program after Ergon Energy supplied sufficient information to support its business case. However, we continue to have concerns about Ergon Energy’s forecast for 3 of its revised programs. We found that Ergon Energy’s $44.6 million maintain reliability program’s cost benefit analysis is be overstated and does not refer to alternative options. We consider that the main driver for the program can be mitigated by Ergon Energy’s proposed mobile generation program and would not require additional capex. We have not included Ergon Energy’s backup reach protection program and OTE Zetron program in our augex forecast. We acknowledge Ergon Energy’s efforts to clarify the backup reach protection program’s alignment with NER requirements. However, Ergon Energy did not sufficiently justify why this program should be funded by additional capex, rather than its business-as-usual expenditure. For its OTE Zetron program, we found there to be a systematic overstatement of benefits, similar to its repex equivalent programs. This is discussed further in Appendix A.
Connections	We have included Ergon Energy’s connections expenditure forecast in the total forecast capex. This was considered and accepted in our draft decision.
Fleet	We have included Ergon Energy’s revised total expenditure forecast of $222.3 million ($2024-25) in the total capex forecast. Our draft decision accepted that an uplift in the forecast period relative to the current period was reasonable but not to the magnitude proposed by Ergon Energy. We considered that Ergon Energy had not sufficiently justified: - expenditure related to a Full Time Equivalent (FTE) uplift due to reductions in network capex; - expenditure to change its replacement programs for elevated work platforms (EWP) and crane borers (CB). Ergon Energy’s revised proposal accepted our draft decision position on the FTE uplift and provided further information on the benefits of its proposed changes to its replacement strategy for EWP and CB where there is a move from a 15 to a 10-year replacement cycle for some vehicles. While some minor gaps in information remain, our assessment of Ergon Energy’s analysis indicates that the benefits of the current and new strategy are likely to fall within an acceptable range.
Property	We have included Ergon Energy’s property expenditure forecast in the total forecast capex. Ergon Energy accepted our draft decision on this capex category.

Driver	Findings and reasons
ICT	We have included Ergon Energy's ICT forecast in the total forecast capex. Ergon Energy accepted our draft decision on this capex category.
Cyber security	We have included Ergon Energy's cyber security forecast in the total forecast capex. This was considered and accepted in our draft decision.
Resilience	We have included Ergon Energy's revised total forecast of $34.6 million ($2024-25) into the total capex forecast. Our draft decision accepted expenditure for Ergon Energy's bushfire and flood program and its new mobile substation program. However, we did not accept its expenditure for its Standalone Power System (SAPS) because there was no evidence of consumer benefit. We also only partly accepted its forecast for its mobile generation program as we were not provided with sufficient information to assess the benefits of the program from a resilience perspective. Ergon Energy's revised proposal accepted our draft position on the SAPS program and submitted a lower forecast for its mobile generation program. Overall, we found that Ergon Energy has provided sufficient evidence to support the prudency and efficiency of its mobile generation program, including a net positive economic case for purchasing mobile generators rather than hiring them during major unplanned outage events. There are some areas of improvement such as a potential overstatement of consumer benefits by applying 0.5 times the VCR for planned outages (i.e. VCR values were developed for unplanned outages and there are currently no published VCR values for planned outages). However, we note that when we apply sensitivities or even remove the benefits of planned outages entirely, it did not change the overall least cost capex solution.
CER integration	We have included Ergon Energy's CER forecast in the total forecast capex. This was considered and accepted in our draft decision.
Capitalised overheads	We have included $966.8 million ($2024–25) in our alternative estimate of total forecast capex. Ergon Energy's revised forecast uses the AER's standard approach for calculating overheads with the addition of the annual 1% productivity adjustment contained in its initial proposal. Our draft decision did not accept Ergon Energy's approach to calculate capitalised overheads. Ergon Energy did not provide sufficient evidence that its approach was reasonable and we found that its approach would be likely to overstate forecast capitalised overheads.
Asset disposals	We have included Ergon Energy's asset disposal forecast in the total forecast capex.
Customer contributions	We have included Ergon Energy's customer contributions forecast in the total forecast capex.

A Reasons for decision on key capex categories

This appendix sets out our assessment of key capex categories and programs/projects within Ausgrid's total capex forecast and the reasons for our decision. This appendix includes:

- Repex (A.1)
- Augex (A.2)

A.1 Replacement expenditure

A.1.1 AER Final decision

We do not accept that Ergon Energy's repex forecast of $2,449.8 million would form part of a total expenditure forecast that reasonably reflects the capex criteria. We have included $1,941.3 million in our alternative estimate of total capex, which is 20.8% lower than Ergon Energy's proposal.

A.1.2 Ergon Energy's revised proposal

Ergon Energy's proposed repex of $2,449.8 million. Table A1 provides a breakdown of Ergon Energy's revised repex. This forecast is 9.9% lower than Ergon Energy's initial proposal.

Ergon Energy has revised its forecast in its key repex programs, lowering its forecast in 5 areas: pole, conductor, pole top structure, CTG/CTS and secondary system programs. It accepted our draft decision on the opportunistic replacement of distribution switchgear and distribution switchgear assets.

Table A1 Ergon Energy's 2025–30 revised repex forecast, by key programs ($ million, $2024–25)

Replacement programs	Initial proposal	Draft decision	Revised proposal	% change (RP to IP)
Pole	815.1	420.5	744.4	-8.7%
Conductor	537.8	405.5	494.8	-8.0%
Pole top structure	262.3	138.1	252.6	-3.7%
Distribution switchgear	88.0	70.7	69.8	-20.7%
Distribution transformer	152.6	118.4	118.4	-22.4%
Service line	87.6	87.6	87.6	0.0%
Clearance (CTG/CTS)	181.1	105.7	164.8	-9.0%
Secondary systems	132.9	90.6	111.3	-16.3%
Others	461.3	405.6	405.9	-12.0%
Total repex forecast	**2,718.8**	**1,842.7**	**2,449.8**	**-9.9%**

Source: Ergon Energy revised regulatory proposal 2025–30 and AER analysis. Numbers may not sum due to rounding.

A.1.3 Reasons for the decision

As noted in our draft decision, our position on Ergon Energy's forecast capex was a placeholder given the major information gaps in its proposal, especially in repex which is the driver of its capex forecast for the 2025–30 period. We acknowledge the efforts Ergon Energy has made to address these gaps including extensive engagement with us post release of our draft decision, which included AER staff attending face-to-face meetings over several days to work through the information it had available. We also note that Ergon Energy's new and additional supporting information has allowed us to assess Ergon Energy's proposal afresh, and to undertake deeper analysis to better understand the basis of Ergon Energy's forecast.

Our recommended final decision is a higher repex forecast relative to the draft decision, being $97 million higher than the draft decision. The higher repex forecast in the final decision is reflective of our finding in some cases of Ergon Energy's supporting information justifying more capex (in Ergon Energy's pole and CTG/CTS programs). But, in other cases, we found the new and additional information which supported maintaining our draft decision position (for pole top structure, conductor and repex-related secondary system programs). Where we have derived alternative forecasts, these have been based on a bottom-up assessment which addresses Ergon Energy's concerns about the draft decision alternative forecast being based on benchmarking against Essential Energy's network.

In coming to final decision, we also had regard to stakeholder submissions. We received 3 submissions about Ergon Energy's repex – from the CCP30, Electrical Trades Union, and EQL's RRG. We note the concerns raised by the EQL RRG and CCP30 that, in the lead up to the revised proposal, Ergon Energy focused on informing its customers about its revised proposal rather than genuinely seeking feedback from customers. Both the EQL RRG and CCP30 also noted perceived bias in Ergon Energy's presentations to consumers groups about the AER's draft decision. The EQL RRG submits that:[18]

> 'The [EQL] presentation [to the VoC] was more akin to push polling than an accurate presentation of the situation and the reasons for the AER Draft Decision. The information provided to the VoC meant that they received only limited information to be able to express an informed view of the Draft Decision.'

We also note the submission from the Electrical Trades Union which supports Ergon Energy's revised proposal where it states, 'With an aging network and significant population growth in our view the AER must allocate sufficient funds to ensure a safe and reliable electricity network.'[19] The Electrical Trades Union makes particular note of risks in relation to clearance-to-ground and clearance-to-structure defects, poles and conductors.

We discuss our specific findings in Ergon Energy's revised repex forecast below.

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[18] EQL Reset Reference Group, *Submission on the Australian Energy Regulator's Draft Decision and Ergon Energy Network's Revised Regulatory Proposal for 2025-30*, January 2025, p.31.

[19] Electrical Trade Union (QLD and NT), *Ergon Energy – Revised Regulatory Proposal 2025-30*, p.3.

Pole program

Ergon Energy's revised forecast for its poles program is $744.4 million. Table A2 provides a breakdown of Ergon Energy's poles program forecast.

Ergon Energy's revised proposal is 8.7% lower relative to its initial proposal as it accepted our draft decision on opportunistic replacement of distribution switchgear and distribution switchgear assets. However, Ergon Energy maintains other elements of its initial proposal, forecasting 83,155 pole replacements, approximately 16,600 poles per annum including a staking volume of 5,000 per annum. Its forecast is a continuation of its ex-post volumes, where its forecast is based on a historical 3-year average volume of replacement from 2020–21 to 2022–23. It also maintains its initial proposal forecast on the opportunistic replacements of pole top structure and service line assets.

Table A2 Ergon Energy's revised pole program ($ million, $2024–25)

Pole programs	Initial proposal	Draft decision	Revised proposal	Final decision	% change (FD and RP)
Stand-alone program					
Pole defect program	478.8	218.8	479.4	282.6	-40.9%
Opportunistic replacements					
Pole top structure asset	155.8	71.1	155.6	91.9	-40.9%
Distribution switchgear asset	73.3	58.9	38.7	58.9	n/a
Distribution transformer asset	76.1	57.6	39.5	57.6	n/a
Service line program asset	31.2	14.2	31.3	18.4	-40.9%
Total opportunistic replacements	**336.3**	**201.7**	**265.0**	**226.8**	**n/a**
Total pole program	**815.1**	**420.5**	**744.4**	**509.5**	**-31.6%**

Source: AER analysis. Numbers may not sum due to rounding.

As Table A2 shows, our final decision is an alternative forecast that is 31.6% lower than Ergon Energy's total poles program forecast. After reviewing all the information before us, we continue to hold the position that Ergon Energy's forecast poles repex is overstated and not prudent and efficient. However, we acknowledge that new information Ergon Energy has provided in its revised proposal indicates that there are valid reasons for a move from our draft decision position. We note the following key findings:

1. Ergon Energy has not provided sufficient evidence to demonstrate that its elevated historical replacement volumes should continue at the same rate in the forecast period.
2. We have placed less weight on Ergon Energy's updated risk cost model in coming to our position. While Ergon Energy has updated its risk cost model to reflect EMCa and our concerns in the draft decision, the risk cost model was not used as the basis of its

forecast. Nonetheless we have reviewed the risk cost model and have concerns with the number of errors in the model.

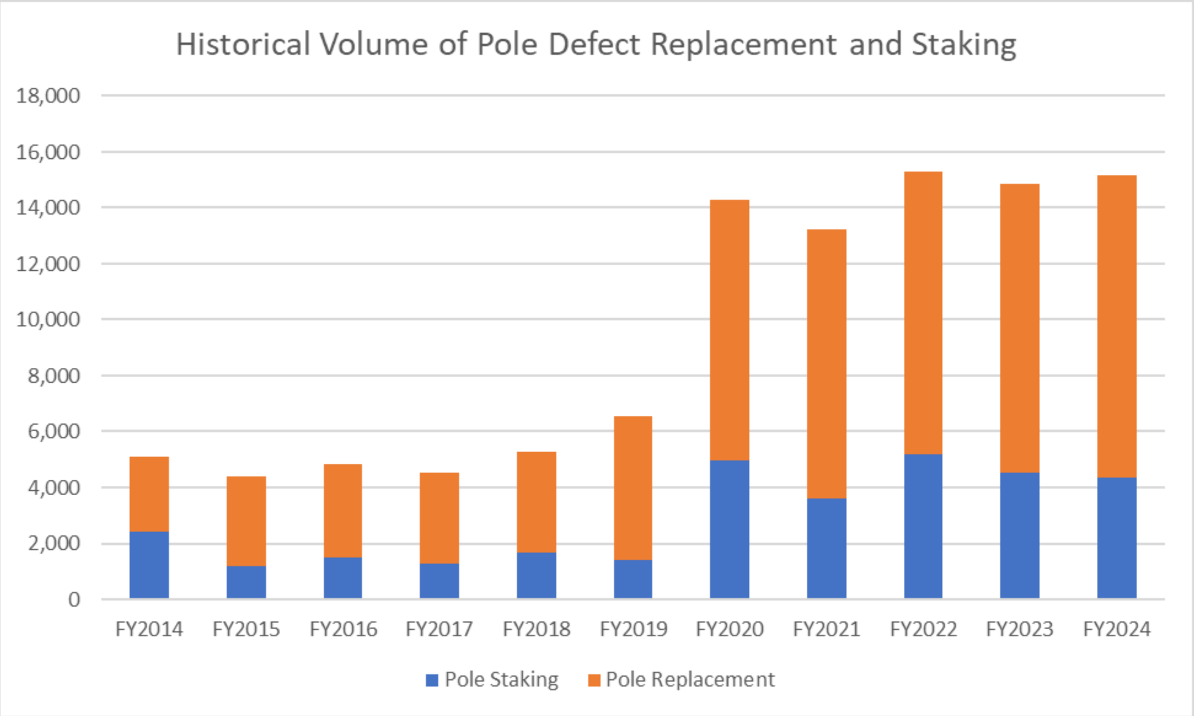
3. Ergon Energy's revised proposal includes opportunistic replacement of pole top structures and service lines when replacing poles. We consider this is to be reasonable and consistent with good industry practice.
4. Ergon Energy has different pole management practices to Energex (and, therefore, its increased replacement volumes in the ex-post and forecast period is not related to Ergon Energy trying to align its pole management practices to Energex).
5. We acknowledge the information Ergon Energy has provided to explain the differences in Ergon Energy's and Essential Energy's operating environment. However, as noted in our draft decision, our benchmarking of Ergon Energy against Essential Energy to derive an alternative forecast in our draft decision was a placeholder because of a lack of information available to us at that time. We therefore have not benchmarked Ergon Energy against Essential Energy in our derivation of alternative forecasts.

We discuss our findings further below.

1. Ergon Energy has not provided sufficient evidence to demonstrate that its elevated historical replacement volumes should continue at the same rate in the forecast period.

Figure A1 shows the step increase in Ergon Energy's pole replacement volumes from 2018/19.

Figure A1 Ergon Energy's historical pole defect replacement and staking volumes



Source: Ergon Energy's response to IR067, Ergon 5.5.01D RIN Repex Forecast and AER analysis

As noted in our draft decision, Ergon Energy observed an increase in its pole failures in 2017/18 and, therefore, it undertook a series of activities to address this, including improving its data collection of defective poles and, in early 2019, a review of its pole strength calculations. This review led to the following changes:

- Reducing pole inspection cycles of 6 and 8 years to 5 years to align with ESCOP specifications
- Improving field staff training in data capture and collection
- Applying new standards to pole management by updating its pole inspection serviceability calculations.

These changes and decisions impacted its asset management practices for poles and led to an increase in reported pole defect rates. Ergon Energy's response in the ex-post period was to increase its pole replacement volumes considerably during the ex-post period (2018–23), which was a key driver of its total capex forecast overspend in that period.

In its revised proposal, Ergon Energy submitted new reasoning for its increased pole defects in the ex-post period and why this elevated level of pole replacement should continue into the forecast period. It submitted that its low strength 3kN poles installed in the western region are the primary pole construction that drove the higher replacement rates in the ex-post period and expects the high failure rates for this type of pole to continue in the forecast period. Further, its improved pole serviceability calculations have increased the number of defects of other pole types and therefore the same higher level of pole replacements is required in the forecast period:[20]

> 'Since 2015, there has been an upward trend of pole failures, primarily due to ageing low strength poles (3 kilonewton (kN)). Improved pole serviceability calculations led to higher volumes of pole replacements in the 2020 – 2025 period. Due to this change, we anticipate earlier detection of pole defects and have identified a need to replace in response to high pole failure rates within our low strength 3kN poles. As a result of the driver to maintain a serviceable population, there is a need to increase investment in the next regulatory period by maintaining 16,600 pole replacements per annum.'

After reviewing Ergon Energy's new supporting material, we found the following:

- The step up in pole replacement from 2019 is driven largely by the combination of the retrospective application of a new standard and a shortened inspection cycle which brings forward pole replacement.

  Ergon Energy has adopted and subsequently retrospectively applied a new standard (AS 7000:2010) to its existing pole population. This has resulted in more pole replacements than is prudent and efficient. The retrospective application of standards to existing assets is not consistent with good industry practice.

  We note the CCP30 in its submission also confirms that the retrospective application of standards to existing assets is not consistent with good industry practice:[21]

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20 Ergon Energy, *Repex 2025-2030 – Repex Ex-Post and Ex-ante Narrative*, 18 November 2024. p.13.

21 Consumer Challenge Panel, *Advice to the AER regarding the Draft Decision and Revised Regulatory Proposal 2025-30*, January 2025, p.26.

> 'Whilst much is written regarding asset replacement in the Draft Decision and the Proposal, one thing that seems to stand out is the application of newer standards to assessing pole safety and hence replacement need. We contend that, without unequivocal evidence that the existing pole fleet must be subject to the new standards, only new installations should be subject to new standards. This is consistent with general practice for implementing updated standards elsewhere.'

In relation to Ergon Energy's move to a shortened inspection cycle, we acknowledge that Ergon Energy's move from an 8 to 6 to then a 5-year pole inspection cycle is appropriate. A shorter inspection cycle will mean more pole defects identified sooner and therefore more intervention (replacing or staking) earlier. Therefore, an increase in its pole replacement compared to the levels prior to 2018 in the current period is reasonable as Ergon Energy moves from its longer to shorter inspection cycle.

- Ergon Energy's forecast is driven by the retrospective application of the new standard and not by its shorter 5-year pole inspection cycle. As Ergon Energy's historical volumes include replacement volumes based on the inefficient practice of the retrospective application of a new standard, these historical volumes do not form a reasonable baseline from which to derive forecast volumes.

  A 5-year pole inspection cycle aims to inspect every pole in those 5 years. This means that, from 2018/19, the additional poles replaced due to the shortened inspection cycle (i.e. pole replacement brought forward in a once-off manner) will have been fully addressed in the first shortened cycle. Therefore, the 5-year inspection cycle would have contributed to additional pole replacement in the current period but will not contribute to additional pole replacement volumes in subsequent 5-year inspection cycles.

  However, the impact of the retrospective application of the standard adds poles to effectively "catch up" with the application of the higher standard in the first cycle. This will continue to add additional poles in subsequent inspection cycles due to the higher condition criteria being applied.

- We acknowledge Ergon Energy concerns with its low density 3kN poles. Although we note that Ergon Energy's concerns with its low density 3kN poles only came to light post release of our draft decision.

  We acknowledge that some of the desktop assessment in Ergon Energy's revised proposal indicates that there may be a concern with decaying 3kN poles. While these poles represent only about 10% of Ergon Energy's pole population, they make up about 25% of pole failure rates where the possibility of staking this type of pole is lower compared to other pole types.[22]

- Ergon Energy's staking rate is about 30% in the forecast period, which is on the lower end compared to other Distribution Network Service Providers (DNSPs). The staking rate for DNSPs is typically around 30-40%.

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22 Ergon Energy, *5.5.02A – Pole Replacements Business Case*, 18 November 2024, p 19.

We note that Ergon Energy's lower staking rate is partly attributable to its previous long inspection cycles that resulted in pole interventions only occurring when poles were already in a deteriorated condition that was less suitable for staking. We understand this resulted in a higher replacement rate and a lower staking rate. However, with the move to a 5-year inspection cycle in 2019, we would expect staking rates to increase into the second (post 2023) and subsequent inspection cycles.

- Ergon Energy submits root cause analysis (RCA) as supporting information to demonstrate concerns with its 3kN poles. We found its root cause analysis to not be credible.

  Consistent with good industry practice, a RCA is a critical first step to identify the underlying factor or issue that has led to an event or failure. Once undertaken, solutions can then be implemented to address the underlying factor or issue. Ergon Energy's RCA was undertaken in October 2024, after we released our draft decision, and not after the increase in pole failures in 2017/18. We also note that its RCA appears to be a desktop analysis of pole data, whereas a RCA of this nature would typically involve an in-depth forensic review of all failures and confirmation of the actual volume of unassisted failures in a consistent manner.

2. *We have placed little weight on the outcomes of Ergon Energy's risk cost model as historical trend is the basis of its forecast. Regardless, we have concerns about the robustness of Ergon Energy's risk cost model.*

We engaged with Ergon Energy on its revised risk cost model after release of our draft decision. The risk cost model is used to demonstrate by comparison to other options that Ergon Energy's forecast pole replacement volumes are efficient. However, we understand that Ergon Energy did not use its revised risk cost model to derive forecast pole replacement volumes.

Even though Ergon Energy's forecast was not derived using the risk cost model, but a separate model based on its historical replacement rates, we have a number of concerns with the risk cost model. We identified significant data and modelling issues which overstates the benefits of its proposed investments. Some of the key issues are as follows:

- Our standard approach is an analysis period of 20 years for distribution assets and 25 years for transmission assets. Ergon Energy's revised model extends the analysis period from 20 years to 37 years where 70% of the benefits resides in the last 10 years (i.e. from year 27 to year 37) using an exponential risk profile;
- We found an overstatement of financial risk which makes up over 50% (i.e. $50 million) of the total risk of $91 million in the base year. By Ergon Energy's definition, its financial risk is the likely total replacement costs incurred by the failure of an asset under emergency.[23] Since Ergon Energy has about 100 unassisted failures per annum at a replacement cost of between $5,400 (LV pole) to $11,550 (sub-transmission pole), its replacement cost should be in the range of $0.5 million to $1.2 million. As our standard approach uses the incremental costs of replacement under emergency, Ergon Energy's

23 Ergon Energy, *5.5.02A – Pole Replacements Business Case*, 18 November 2024, p 34.

financial risk should be considerably lower, a fraction of its unassisted failure replacement cost (i.e. less than $0.5 million); and

- By adjusting the model using our standard approach, the optimum pole replacement volume is less than our draft decision.

3. *Ergon Energy's revised proposal includes opportunistic replacement of pole top structures and service lines when replacing poles. We consider this is to be reasonable and consistent with good industry practice.*

As noted in our draft decision, opportunistic replacement is a practice where other assets are replaced at the same time as targeted assets. These other assets are at the same location as targeted assets but are usually of lesser value and at a lower level of replacement priority.

Opportunistic replacement can be considered good industry practice where it leads to cost efficiencies. This may involve, for example, replacing low value assets such as an ageing crossarm or conductor during a pole replacement.

Consistent with our draft decision, we acknowledge that the opportunistic replacement for pole top structures and service lines is an observed and prudent practice by DNSPs. We have made reductions to the opportunistic replacement of pole top structure and service line assets in line with our reduction to Ergon Energy's forecast pole volumes.

4. *New information provided by Ergon Energy demonstrates that it has different pole management practices to Energex.*

In our draft decision, we noted that Ergon Energy's application of Energex's pole management practices has led to greater pole replacement than is prudent and efficient.

In its revised proposal, Ergon Energy explained that since the 2016 merger of Ergon Energy and Energex into the consolidated entity of Energy Queensland, Ergon Energy has streamlined some of its practices with Energex. However, this has not extended to its pole management practices. Ergon Energy has provided new information about the distinct differences in the asset management practices between Ergon Energy and Energex. Therefore, the changes to Ergon Energy's pole management practices following its review of these practices in 2018/19 were not made to align with Energex's pole management practices. After reviewing this additional new information, we are satisfied that Ergon Energy's pole management practices are different to Energex's.

5. *We acknowledge information Ergon Energy has provided to explain the differences in Ergon Energy's and Essential Energy's operating environment. However, as noted in our draft decision, our benchmarking of Ergon Energy against Essential Energy to derive an alternative forecast in our draft decision was a placeholder because of a lack of information available to us at that time.*

Ergon Energy notes that it has a different operating environment compared to Essential Energy:[24]

- Due to a legacy design choice, Ergon Energy still has 94,000 3kN wood poles in service, while Essential Energy does not have any. Ergon Energy considers this means that

[24] Ergon Energy, *5.5.02A – Pole Replacements Business Case*, 18 November 2024, p 19.

these 3kN poles contribute materially to annual pole failures (averaging 25% failure rate over 5 years).

- Ergon has a lower design Factor of Safety[25] compared to Essential Energy. Ergon Energy considers that its poles may be deemed unserviceable earlier due to faster degradation and lower strength.
- Ergon submits that it has a legislative requirement of a 3-year moving average pole reliability target of 99.99% per annum while Essential Energy have no such targets.
- Ergon considers that its network experiences greater termite damage, humidity and rainfall which means greater degradation, rot and decay of its poles relative to Essential Energy.

We acknowledge and agree with some of Ergon Energy's explanation. As noted in our draft decision, our draft decision on Ergon Energy's forecast capex was a placeholder. Due to our concerns with the information and data provided to us in the initial proposal, we had to explore other avenues to derive an alternative estimate at the draft decision stage.[26] In particular, the data discrepancies, errors, reconciliation issues and information gaps we encountered meant we did not have sufficient confidence in the robustness of the data to undertake a more detailed bottom-up estimate. Thus, our alternative forecast at the draft decision stage was, for several elements, based on benchmarking Ergon Energy against Essential Energy. At the draft decision stage, we undertook comparative analysis between Ergon Energy and other DNSPs and found Essential Energy as the best available business to compare with Ergon Energy. Our draft decision encouraged Ergon Energy to work with us to address the information gaps and discuss other information that would be useful in deriving an alternative forecast. Post-release of our draft decision Ergon Energy has provided us with new information and data, some of which we consider to be sufficiently robust for us to derive alternative forecasts.

Alternative forecast

Our alternative poles volume forecast is 10,000 poles per annum and includes Ergon Energy's 3kN poles. This compares to Ergon Energy's forecast of 16,600 poles per annum and our draft decision of 7,600 poles per annum. We have accepted Ergon Energy's forecast unit rates applied to its poles program.

Thus, our alternative forecast for pole assets (stand-alone program) is $282.6 million. This includes both pole replacement and staking.

As we have reduced Ergon Energy's revised proposal pole volume by 40.9%, we have also reduced the opportunistic replacement of pole top structure and services assets proportionally consistent with our draft decision.

Our alternative forecast also includes an additional $38.3 million due to Ergon Energy's error of proposing lower forecasts for its opportunistic replacement of distribution switchgear and

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25 Factor of Safety is an input factor in the calculation of bending strength of poles. Ergon Energy noted that it has a design Factor of Safety of 2.5 while Essential Energy have a factor of 4.

26 We explored other approaches including bottom-up analysis, backcasting using the repex model and other forms of benchmarking analysis.

transformer assets, when higher forecasts were accepted for these programs in our draft decision.

Alternative pole volumes forecast

We derived our alternative poles volumes forecast based on Ergon Energy's Condition Based Risk Management (CBRM) model.

Ergon Energy provided us with several models in support of its revised forecast:

- Its historical pole data model that it used to derive its forecast;
- Its risk cost model that it used to compare the benefits from its forecast with other options; and
- a CBRM that uses current condition-based information to predict future volumes based on a health index approach

As noted above, we do not consider that Ergon Energy's historical trend is a reasonable proxy for its forecast, and therefore have not used its historical pole data model in deriving our alternative forecast. In addition, when reviewing its historical defect data, we found that Ergon Energy's 3-year historical average is about 14,500 to 15,000 poles per annum (see Figure A1). This is about 10% to 15% lower than the 16,600 poles Ergon Energy is proposing next period.

As noted above, we have concerns with the credibility of Ergon Energy's risk cost model and therefore have not used this model to derive our alternative forecast.

We have reviewed Ergon Energy's CBRM model and consider that its CBRM model is a reasonable model on which to base our alterative volume forecast. The CBRM relies on the Health Index (HI) of an asset to predict future defect volumes, where the HI is based on asset condition information like age, environment, strength ratio and rot level. With a HI assigned to each of its poles, Ergon Energy states that it uses the CBRM model to "to help forecast targeted / proactive replacements and to support the inspection driven defect forecasts developed for its repex program." [27]

Ergon Energy submitted the outcomes of the CBRM to show how it derived key risk metrics - probability of failure and consequence of failure – where these metrics were used to populate its risk cost model. We understand that Ergon Energy did not use the volume outcomes of the CBRM model as its forecast because the model does not take account of monetised benefits, like financial benefits, of its poles program, preferring to rely on the outcomes of its risk cost model which does take these benefits into account.

We consider that the CBRM is a reasonable model on which to derive an alternative poles volume forecast because:

- The CBRM uses different types of condition data to predict future volumes, which is a solid basis to replace assets;
- The CBRM (and HI) is a common asset management tool used by Providers in combination with other information to predict future defects and therefore pole volumes.

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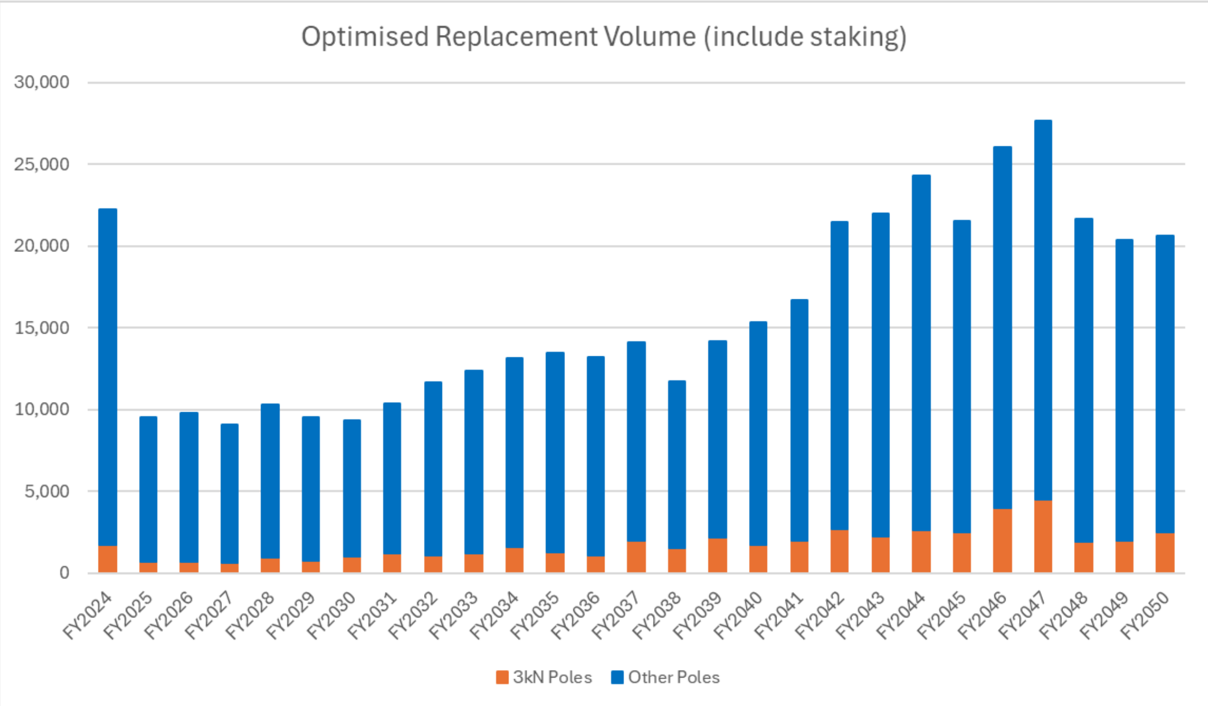
[27] Ergon Energy, *5.5.02A – Pole Replacements Business Case*, 18 November 2024, p 31.

- The outcomes of Ergon Energy's CBRM methodology, which is based on known pole failures/defects to predict future volumes but does not consider monetised costs and benefits, aligns with the Electrical Safety Code of Practice (ESCOP) specifications that also focuses on pole failure rates, specifying a maximum of 1 in 10,000 pole failures in a 3-year rolling average, where there is no requirement to consider the monetised costs and benefits of the pole program; and
- When we re-adjusted the risk cost model to include more reasonable assumptions, we found that the model derives a materially lower pole replacement volume forecast (lower than our draft decision) which does not seem reasonable.

The results of the optimised CBRM model are in Figure A2.

Figure A2 Pole volume forecast from the CBRM



Source: Ergon Energy's predictive model enhancement progression presentation

As can be seen in Figure A2, the CBRM's analysis shows an optimised volume of 48,024 poles for 2025-30 or about 9,600 poles per annum. This volume includes 3kN poles. We have rounded up our alternative forecast to 50,000 poles for 2025-30 or 10,000 poles per annum as a more conservative estimate given the discrepancies we have observed from Ergon Energy's historical data.

It should be noted that the first year in Figure A2 (the optimised replacement volume for 2024) is unusually high. We consider that this is driven by an artificial backlog due to a delay in data capture for pole replacements that are either recently completed, under construction or already committed this period. Thus, the high pole volume in the 2023-24 year either does not exist or would have been replaced prior to the start of next period. Some of these data quality issues were confirmed by Ergon Energy in our meeting in late 2024.

As noted above, we consider that Ergon Energy's pole staking rate is on the low side relative to other DNSPs and should increase with a shorter inspection cycle. We have been conservative and applied a 30% staking rate. Thus, our alternative pole volume of 10,000 poles for the forecast period would include 7,000 of pole replacements per annum and 3,000 pole reinforcements (staking) per annum. This is a total of 50,000 in the forecast period, relative to Ergon Energy's value of 83,000.

Conductors program (opportunistic replacement)

In our draft decision, we accepted Ergon Energy's conductor volumes for its stand-alone program but did not accept all its opportunistic replacements. In its revised proposal Ergon Energy has accepted our draft decision on opportunistic replacement of distribution switchgear and distribution switchgear assets. However, it maintains its initial proposal forecast on the opportunistic replacement for pole, pole top structure and service line assets submitting that these asset replacements are part of an "enabling scope" necessary to meet design requirements.[28]

As Table A3 shows, in its revised proposal, Ergon Energy proposed $494.8 million for its conductor program. This is 8.0% lower than its initial proposal and 21.8% higher than our draft decision.

Table A3 Ergon Energy's revised conductor program ($ million, $2024–25)

Conductor program	Initial proposal	Draft decision	Revised proposal	Final decision	% change (FD and RP)
Stand alone programs					
Defect conductor asset	30.1	30.1	30.0	30.1	n/a
Target conductor asset	210.6	210.6	210.3	210.6	n/a
Opportunistic replacement programs					
Distribution switchgear asset	45.9	36.5	25.7	36.5	n/a
Distribution transformer asset	46.7	34.3	25.3	34.3	n/a
Pole asset	95.6	44.6	95.2	44.6	-53.2%
Pole top structure asset	86.7	40.4	86.2	40.4	-53.2%
Services program asset	22.1	9.7	22.1	9.7	-56.1%
Total opportunistic replacements	**297.1**	**165.4**	**254.5**	**165.4**	**n/a**
Total conductor program	**537.8**	**406.1**	**494.8**	**406.1**	**-17.9%**

Source: AER analysis. Numbers may not sum due to rounding.

Our final decision is to maintain our draft decision position as Ergon Energy did not provide sufficient evidence to support the prudency and efficiency of its forecast.

28 Ergon Energy, *2025-30 Revised Regulatory Proposal*, 2 December 2024, p 68.

In support of its revised proposal, Ergon Energy submits that there are cost saving benefits from opportunistic replacement of pole, pole top structure and service line assets, when replacing conductors:[29]

> ‘we consider there are sufficient efficiency (particularly in regional areas and to avoid multiple truck visits) benefits associated with replacing poles, pole top structures and service lines at the same time as reconductoring instead of replacing them at other times. Other benefits include avoided cost of multiple redeployments to the same areas, reductions in supply risk, safety advantages from reduced overall time of road closures.’

It also submits that “when reconductoring old lines, we must assess the line according to modern standards, specifically AS/NZS 7000.” Therefore, the reasons for its opportunistic replacement of pole, pole top structure and service line assets which it refers to as ‘enabling’ replacement, is to adhere to modern design standards regardless of age or level of defect:[30]

> ‘we must adhere to the modern standards applicable at the time of reconductoring. Over time, standards have become more stringent, so everything from the required pole foundation depth to the strength of poles and crossarms needs to be reviewed for suitability.
>
> In many cases, poles designed and installed decades ago will not meet modern requirements when a new conductor is installed. Therefore, the consequential replacements must be made regardless of age or level of defect.’

We consider that Ergon Energy’s retrospective application of modern standards is not consistent with good industry practice. The application of a new standard should be applied to new line being built, but not where assets are opportunistically replaced regardless of the condition of the asset. We also note that there is currently no clear threshold in the latest design standard (i.e. AS/NZS 7000) outlining the circumstances in which a group of existing assets must be brought to modern standards. Thus, the threshold would be based on Ergon Energy’s internal policies.

We also have overall concerns with Ergon Energy’s scope of work within its conductor program. Ergon Energy submits that when replacing small copper conductors, these must be replaced with larger copper conductors along with supporting assets as there is no modern equivalent of small copper conductors. Noting Ergon Energy’s explanation, we agree that when a small copper conductor needs to be replaced, there might be a need to replace it with a larger conductor. However, our review of Ergon Energy’s copper conductor population reveals that it has replaced most small copper conductors in the current period and now proposes to shift to replacing larger conductors in the forecast period. We have not been presented with sufficient evidence to support the replacement of larger copper conductors in the forecast period or the reason that larger conductor replacement would still require the

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[29] Ergon Energy, *Response to information request IR067*, Question 6 and 8.

[30] Ergon Energy, *5.5.04A – Consequential Replacements Overhead Conductor Business Case*, 18 November 2024, p 11.

replacement of its supporting assets given there are modern equivalents for larger conductors.

Pole-top structures (stand-alone program)

Our draft decision noted that Ergon Energy did not provide sufficient justification for the material step up in its pole top structure program from the ex-post (2018–23) and current (2020–2024) period. Ergon Energy's revised proposal is similar to its initial proposal, where it is proposing to proactively replace pole top structures that have minor defects. It also includes additional information in support of its proposal, being a revised business case and cost benefit model.

Table A4 sets out Ergon Energy's revised pole top structure program forecast. Our final decision is a reduction of 45.3% relative to Ergon Energy's forecast. We were not provided with sufficient evidence to support the prudency and efficiency of Ergon Energy's proactive program to address minor (C3) defects. Our alternative forecast is based on Ergon Energy's historical volumes.

Table A4 Ergon Energy's revised pole top structure program ($ million, $2024–25)

Pole top structure program	Initial proposal	Draft decision	Revised proposal	Final decision	% change (FD and RP)
Defect pole top asset (i.e. P0/P1/P2 defects)	148.2	138.1	138.3	138.1	n/a
Target pole top asset (i.e. C3 defects)	114.1	0.0	114.3	0.0	n/a
Total program	**262.3**	**138.1**	**252.6**	**138.1**	**45.3%**

Source: AER analysis. Numbers may not sum due to rounding.

We found that Ergon Energy's business case did not provide sufficient quantitative evidence to support the proactive replacement of pole top structure assets where there are minor defects. We also found that Ergon Energy overstated the benefits in its cost benefit analysis. Our review of its defect data also indicates that Ergon Energy is overstating the risk associated with these minor defects.

We made the following findings in coming to our position:

- Ergon Energy's own business case indicates that proactive replacement of poles with C3 defects is likely not required. Ergon Energy submits that identified defects are scheduled for repair according to a risk-based priority scheme and that the order of repair is P0/P1/P2/C3/no defect (where P0 and P1 are urgent repairs). It states in its business case that (emphasis added):[31]

  > 'C3 defects are identified from ground and aerial based inspections and are defined as minor deterioration or damage **which requires no specific action**

[31] Ergon Energy, *5.5.03A – Pole Top Structure Replacements Business Case*, 18 November 2024, p 10.

or does not indicate an acceptable likelihood of failure or creation of a hazardous event in the medium term.'

- Ergon Energy refers to an 'emerging risk of C3 defects' but does not provide evidence of emerging risks of poles with C3 defects that would justify proactive replacement. We are therefore concerned that Ergon Energy is seeking to improve (rather than maintain) performance as there is no indicator of emerging risks.

  Ergon Energy provides little evidence that there is a likelihood of increase in its poles with C3 defects failing while in service. A pole with a C3 defect will either be replaced if it fails in service before the next inspection or until the defect level of the pole is upgraded to either a P1 or P2 defect in subsequent inspections. Thus, we would expect to observe an increase in poles with C3 defect failures while in service to support proactive interventions. Our review of Ergon Energy's historical failure of poles with C3 defects while in service indicates that Ergon Energy has significantly overstated the emerging risk with this type of defect. In particular, our review found a total of 9 failures in the last 5 years attributed to C3 defects. This is an average of 2 failures per annum against a total of 300 unassisted failures per annum. Ergon Energy confirmed these results in its response to our information request.[32] This result indicates that Ergon Energy is proposing to increase its existing replacement rate by 86% to mitigate less than 1% of its existing failures (or $12.7 million per failure). We have therefore concluded that Ergon Energy has not identified the need for investment, as it has significantly overstated the risk associated with C3 defects and, therefore, has significantly overstated the investment required to mitigate that risk.

- Ergon Energy submits that its targeted program has a positive net NPV of $170 million. However, statements in its business case indicate that it is uncertain about the realisation of these benefits to consumers. We also found that its cost benefit analysis significantly overstates the benefits from the targeted program.

  Ergon Energy admits that the benefits to customers of the proactive program are unclear:[33]

  > 'Ergon Energy is proposing to address approximately 10% of the C3 defects in the 2025-30 period to examine whether this strategy will yield the necessary improvements to the service levels and reliability for our customers.'

  In relation to its cost benefit analysis, we found the following:

  – Ergon Energy states its largest risk type, financial risk (the incremental cost of replacing an asset as a result of failure under emergency), is $30 million for the base year of 2025-26. This value is significantly overstated because Ergon Energy has about 300 unassisted failures per annum and Ergon Energy estimates that each failure costs $2,800, meaning its total financial risk for any given year would be less than $1 million, rather than $30 million.

32 Ergon Energy, *Response to information request IR067, Question 21*.

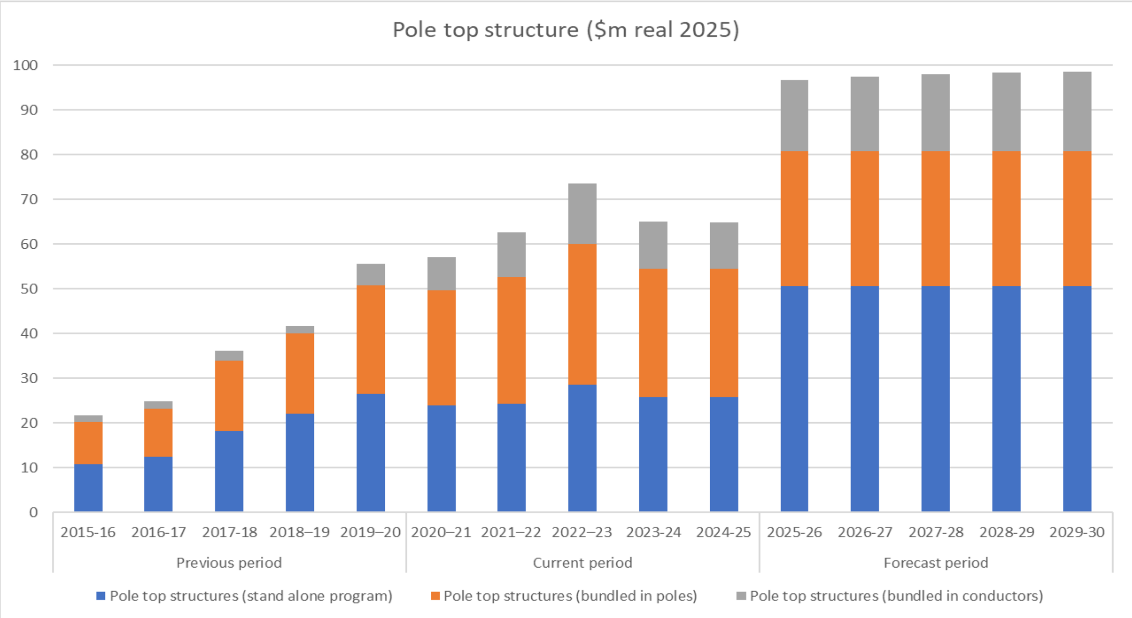
33 Ergon Energy, *5.5.03A – Pole Top Structure Replacements Business Case*, 18 November 2024, p 5.

  – Ergon Energy extended the NPV period from our standard approach for distribution assets of 20 years to 35 years for pole top structures. Applying a longer NPV period has a material impact and we observed a doubling of the total risk from $140 million to $270 million between year 20 and year 35.

- Ergon has not had regard to the medium to long-term benefits from the large volume of non-defective pole top structure assets being opportunistically replaced in other programs this period and next period.

  Figure A3 shows actual and forecast pole top structure replacement. As can be seen, Ergon Energy's opportunistic replacement of pole top structures in the current period is higher than its stand-alone defect program. We consider that the inclusion of the potential benefits of these non-defective opportunistic replacements would likely diminish the need for a targeted program in the forecast period.

Figure A3 Total pole top structure replacement over time (historical and forecast)



Source: AER Draft Decision – Ergon Energy distribution determination 2025-30

CTG/CTS

In our draft decision, we accepted Ergon Energy's clearance volumes for both CTG and CTS but applied lower unit rates (lower by 42%). Table A5 sets out Ergon Energy's revised CTG/CTS program. Ergon Energy's revised proposal is 9.0% lower relative to its initial proposal. While it lowered its CTG unit rate by 16.0%, it also increased its CTS unit rate by 47.5%.

Table A5 Ergon Energy's revised CTG/CTS program ($ million, $2024–25)

Clearance programs	Initial proposal	Draft decision	Revised proposal	Final decision	% change (FD and RP)
Clearance to ground (CTG)	161.1	94.0	135.3	103.4	23.6%
Clearance to structure (CTS)	20.0	11.7	29.5	11.7	-60.3%

Clearance programs	Initial proposal	Draft decision	Revised proposal	Final decision	% change (FD and RP)
Total CTG/CTS program	**181.1**	**105.7**	**164.8**	**115.2**	**-30.2%**

Source: AER analysis. Numbers may not sum due to rounding.

Consistent with our draft decision, our final decision accepts Ergon Energy's volume forecast for CTG and CTS. While we have not accepted Ergon Energy's revised higher CTG unit rate, we have applied a higher unit rate relative to the draft decision. In relation to the CTS unit rate, we were not convinced about the reasonableness of Ergon Energy's higher CTS unit rate when compared against its historical implied unit rates.

We discuss our findings on CTG and CTS programs below.

Clearance-to-ground program

Ergon Energy submits that:

- A re-tension rate of 10% is a more reasonable forecast, compared to the re-tension rate of 46% that the AER applied in its draft decision.[34]
- The re-tension unit rate of $1,100 that the AER applied in its draft decision is based on an incorrect assumption. It proposes an average re-tension unit rate of $5,117.[35]

Based on the new information Ergon Energy has provided, we found that:

- Ergon Energy has an internal policy requiring the conversion of existing overhead lines to the current design standards when alterations are made to an existing line, which we consider is retrospective application of a new standard.[36] We do not consider that this practice is consistent with good industry practice. We have therefore maintained our draft decision position and applied a re-tension rate of 46%, rather than Ergon Energy's proposal of a 10% re-tension rate.
- We acknowledge that the re-tension unit rate of $1,100 we applied in our draft decision was not reflective of the average re-tensioning requirements faced by Ergon. Thus, our draft decision position understated the scope requirements.
- Ergon Energy provided a detailed unit rate build up totalling $2,952 in June 2024 as an example of how it typically addresses low voltage defects that require the re-tensioning of multiple spans.[37] In its revised proposal, Ergon Energy increased this estimate from $2,952 to $5,117 citing that *'low voltage re-tension activities typically cost between $3,900 (simple) & $6,300 (complex) depending on travel time to site from depot, traffic control requirements, risk assessments, volume of switching required for access, length*

34 We understand that clearance gaps less than 20cm can typically be addressed via re-tensioning, therefore we derived the cost to re-tension where the clearance gaps were less than 15cm. This is about 46% of all clearance gap defects.

35 Ergon Energy, *5.6.01 – Clearance to Ground & Structure Program Business Case*, 19 November 2024, p 7.

36 Ergon Energy, *Response to information request IR067*, Question 11.

37 Ergon Energy, *Response to information request IR050*, Question 5.

of strain section and number of conductor fittings to be re-made. An average of $5,117 is used for the revised proposal for a single retention activity.'.[38]

- While we acknowledge Ergon Energy's re-tension cost per defect might be higher than our draft decision of $1,100, we have little confidence that Ergon Energy's latest estimate is reasonable given the lack of historical data to substantiate its costings and a material variance within 6 months of its original estimate of $2,952 without a detailed explanation or cost breakdown.
- We consider that a unit rate of $2,952 is the best forecast unit rate to apply in the circumstances, as it is the last known unit rate with a detail cost breakdown we have previously acknowledged and reviewed.

Clearance-to-structure program

Ergon Energy submits that its unit rate of $22,563 per defect is reasonable as it is based on its actual unit rate in 2023–24. This is higher than what we applied in our draft decision and what Ergon Energy included in its initial proposal.

In response to our information request, Ergon Energy provided historical defect volumes, expenditure and the annual implied unit rate for CTS. This is set out in Table A6.

Table A6 Ergon Energy's historical CTS defects and expenditures

Year	CTS defects	Expenditure ($)	Implied unit cost ($)
2018/19	973	73,122	75
2019/20	628	-	-
2020/21	614	575,373	937
2021/22	224	216,873	968
2022/23	238	2,011,542	8,452
2023/24	523	11,970,639	22,888

Source: Ergon Energy's response to information request IR068 Question 6 and AER analysis.

We do not consider that Ergon Energy's proposed unit rate of $22,563 is a reasonable forecast as it is based on a single year and the highest implied unit rate in the historical period. To retest the robustness of our draft decision estimate of $11.7 million, for the 6-year historical period, we derived an implied unit rate of $4,640 or $6.1 million for this program based on the information in Table A6. Based on Ergon Energy's forecast volume of 226 per annum, we also consider that the average unit cost of 2021–22 and 2022–23 years is likely a better fit for the forecast period, which resulted in similar implied unit rate of $4,710 or $6.1 million for this program. However, given the volatility of Ergon Energy's historical unit rates, we have maintained the higher unit rate from our draft decision as a conservative estimate.

We also note our concerns that Ergon Energy has not demonstrated that it has sufficiently pursued and recouped its CTS cost from third parties that have caused the clearance

[38] Ergon Energy, *5.6.01 – Clearance to Ground & Structure Program Business Case*, 19 November 2024, p 7.

breach. This means that its forecast cost for this program is overstated, with inefficient cost allocation placed on the overall consumer base rather than recovering these costs from the specific customer at fault. Unlike CTG, CTS is typically caused by third parties encroaching on the network's clearance zones.

Repex-related secondary systems

In its revised proposal, Ergon Energy forecasts $111.3 million for repex-related secondary systems. As Table A7 shows, while it has accepted our draft decision on relay replacements, Ergon Energy provided revised forecasts for its Grid Communications and Operational Technology programs. These revised forecasts are lower than those in Ergon Energy's initial proposal, but higher than those in our draft decision. Ergon Energy also provided new additional information including NPV models to support its new forecasts.

Table A7 Ergon Energy's revised secondary system programs ($ million, $2024–25)

Secondary system programs	Initial proposal	Draft decision	Revised proposal	Final decision	% change (FD and RP)
Grid communications	98.6	62.2	78.7	62.2	26.5%
Operational technology	15.7	9.9	14.0	9.9	41.4%
Relay replacements	18.6	18.6	18.6	18.6	0%
Total program	**132.9**	**90.6**	**111.3**	**90.6**	**18.7%**

Source: AER analysis. Numbers may not sum due to rounding.

Our final decision maintains our draft decision position. This is because we were not provided with sufficient evidence to support the prudency and efficiency of Ergon Energy's revised forecasts. We made the following findings in coming to our position:

- When we assessed Ergon Energy's NPV models, we found a material overstatement of benefits which in turn overstates the repex to achieve these benefits. The overstatement of benefits appears to be a systemic issue across Ergon Energy's NPV models.
- In particular, for Ergon Energy's Grid Comms program, Ergon Energy's benefit calculation is based on the VCR and the avoided finance risk (cost for emergency response), the latter contributing mostly to the benefits modelled. Ergon Energy estimates the total financial risk for this program at $609 million (total consequence cost), and then multiplies this by Ergon Energy's estimated likelihood of equipment failure to derive a total annual risk value of $27 million (consequence multiplied by the probability of failure) for comms equipment failure. We consider these values to be materially overstated by several orders of magnitude.
- The calculation of the financial benefits is based on the full cost of replacing the failed asset – including the fully installed cost of the new asset. Using the full cost of replacement results in material overstatement of costs. This is the same approach Ergon Energy applied in its NPV analysis for pole and other repex programs. As each asset will ultimately require replacement when it is efficient to do so, the appropriate consequence

costs should be the incremental financial costs[39] associated with a failure event, not the total replacement cost.

- The systemic issue of overstated benefits also appears in its NPV analysis for its operational technology programs.

[39] The incremental financial cost is the emergency response cost (callout cost) and the incremental cost due to the earlier asset replacement expenditure.

A.2 Augmentation expenditure

A.2.1 AER's final decision

We do not accept Ergon Energy's revised augmentation expenditure (augex) forecast of $489.2 million would form part of a total capex forecast that reasonably reflects the expenditure criteria. We have included $432.9 million for augex in our alternative estimate, which is $56.3 million lower than Ergon Energy's revised proposal. Our alternative estimate comprises of revisions to Ergon Energy's distribution growth and SCADA, protections and communications augex categories.

A.2.1.1 Ergon Energy's proposal

Ergon Energy proposed an augex forecast of $489.2 million.[40] Table A8 provides a breakdown of the augex program categories, including associated subcategories. This forecast is 7.9% lower than Ergon Energy's initial proposal.

Table A8 Ergon Energy's 2025–30 augex revised proposal ($ million, $2024–25)

Augmentation program	Initial proposal	Draft decision	Revised proposal
Sub-transmission growth	188.6	188.3	188.5
Reliability	14.0	14.0	14.1
Distribution Growth	216.6	166.0	210.8
Distribution growth (24 projects)	166.0	166.0	166.1
Maintain reliability	50.6	0.0	44.6
SCADA, protections and communications	94.0	60.5	75.8
Grid communications	24.6	15.8	19.4
DC system and duplication and bus overcurrent protection	13.6	5.5	5.5
Backup reach protection improvement program	11.1	0.0	11.1
Operational technology	3.4	1.5	1.5
Protection	2.3	0.3	0.9
Intelligent grid and grid control	39.0	37.4	37.4
Total augmentation	**513.2**	**428.8**	**489.2**

Source: Ergon, 5.2.01 – Model - SCS Capex model, January 2024, AER, Draft Decision – Ergon Energy – 2025-30 Distribution revenue proposal – Capex Model, September 2024 and Ergon, SCS Capex model, November 2024.

Note: Numbers may not add due to rounding. Modelling adjustments and corrections have been applied to the previous regulatory stage.

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40 Ergon Energy, *2025-30 Revised Regulatory Proposal*, December 2024, p 69

Ergon Energy revised its proposal for individual programs that were not accepted during the draft decision. These include $44.6 million for its distribution feeder augmentation maintain reliability program and $15.2 million for 4 SCADA, protections and communications programs.

Distribution feeder augmentation maintain reliability program

Following our draft decision, Ergon Energy acknowledged our feedback and revised its 'maintain reliability program' to target 8 regional communities that are subject to long outages. The program's revised forecast is $44.6 million, an 11.8% decrease from its initial proposal, to install 8 permanent diesel generators.[41] Ergon Energy stated that due to the introduction of the Value of Network Resilience it now had the means to value longer outages, as its previous absence meant that investment in such a project was not economically justifiable.[42]

Backup reach protection improvement program

For its backup reach protection program, Ergon Energy did not revise is proposed forecast of $11.1 million. Ergon Energy acknowledged that it had not clearly demonstrated how its original proposal was required under the NER.[43] In its revised business case, Ergon Energy provided clarification that its backup reach protection program would apply to its high voltage network and specifically referenced clauses in the NER it believed to be relevant.

Grid communications and operational technology programs

For grid communications, Ergon Energy revised its forecast to $19.4 million, 21.1% lower than its initial proposal. After reassessing its technological options and project scope, Ergon Energy has revised its preferred options for the following programs:

- Reliability core MPLS and fibre ($1.9 million, 64.8% lower than its initial proposal), and
- Reliability edge fringenet and backhaul ($1.7 million, 50.0% lower than its initial proposal).

Ergon Energy also revised its forecast for its operational technology environment (OTE) Zetron project to $0.5 million, which is an 80.0% reduction from its regulatory proposal.

For each project, Ergon Energy submitted that a more competitive supplier base, efficiencies in its technological provisioning and improved delivery structure contributed to the reduction in forecasted program costs.[44]

A.2.1.2 Reasons for decision

In our draft determination, we did not include certain augex programs as Ergon Energy was not able to demonstrate prudency or deliverability and provided minimal options analysis. We acknowledge that Ergon Energy has moved to rectify this by either narrowing its project scope or providing further clarification. However, we found that the business cases still

41 Ergon Energy, *5.6.02A - Business Case - Distribution Growth Unplanned Reliability*, November 2024, p 9.

42 Ergon Energy, *5.6.02A - Business Case - Distribution Growth Unplanned Reliability*, November 2024, p 6.

43 Ergon Energy, *5.6.03 - Business Case – Backup Protection*, November 2024, p 6.

44 Ergon Energy, *IR#072 Ergon Response*, January 2025.

lacked sufficient information to support is proposed forecast. The exception to this is its resubmitted grid communications program. Through an information request we were able to ascertain more information about the options for both projects and efforts towards deliverability, which included additional labour acquisition. We note that Ergon Energy has taken steps to come to a more efficient forecast through detailed risk analysis and has moved to increase its resourcing to ensure deliverability during the forecast regulatory period.[45] For these reasons, we have accepted Ergon Energy's revised grid communications program in our total augex forecast.

Table A9 outlines our alternative forecast, including our reductions for specific programs. For reasons we detail below, we have excluded 3 programs from the total augex forecast. For the clearance to ground program, we have reallocated it back to repex. Our reasoning is consistent with our draft decision and details about our alternative forecast are included in section A.1.3.

Table A9 Ergon Energy's 2025–30 augex alternative forecast ($ million, $2024–25)

Augmentation Program	Revised proposal	Alternative forecast	Difference ($)	Difference (%)
Sub-transmission growth	188.5	188.5	0	0.0%
Reliability	14.1	14.1	0	0.0%
Distribution Growth	210.8	166.1	44.6	-21.2%
Distribution growth (24 projects)	166.1	166.1	0	0.0%
Maintain reliability	44.6	0	44.6	-100.0%
SCADA, protections and communications	75.8	64.2	11.6	-15.3%
Grid communications	19.4	19.4	0	0.0%
DC system and duplication and bus overcurrent protection	5.5	5.5	0	0.0%
Backup reach protection improvement program	11.1	0	11.1	-100.0%
Operational technology	1.5	1.0	0.5	-33.3%
Protection	0.9	0.9	0	0.0%
Intelligent grid and grid control	37.4	37.4	0	0.0%
Total Augmentation	**489.2**	**432.9**	**56.3**	**-11.5%**

Source: Ergon, SCS Capex model, November 2024, AER Analysis.
Note: Numbers may not add due to rounding.

[45] Ergon Energy, *IR#072 Ergon Response*, January 2025.

Distribution feeder augmentation maintain reliability program

For Ergon Energy's revised $44.6 million reliability program, we have maintained our draft decision to not include this in our total forecast augex. We have assessed the costs and the benefits of this program, and we consider the benefits of this program to be overstated. We found that despite Ergon Energy's attempt to reduce the project's scope to only target specific regional areas, the proposal overlooked 2 significant aspects. Primarily, Ergon Energy did not include any consideration of alternative options, such as using its mobile generation program strategically to mitigate long outage times in these communities. The mobile generation program, which we accepted in our draft decision, uses portable systems to restore energy more effectively and efficiently during disasters and network contingency conditions.[46] In not including any reference to this, we consider Ergon Energy has not sufficiently addressed the concerns we raised in our draft decision. Specifically, Ergon Energy has not developed an effective overarching strategy, as overlapping programs such as these would yield greater efficiencies.[47]

Secondly, Ergon Energy's business proposal also included information about CER penetration in each region it intended to address. We note that penetration in these areas almost reached or exceeded 25%, meaning a significant portion of the area could already have the means to reduce its outage times.

Overall, we determined that without consideration of these significant factors in its analysis, Ergon Energy's proposed forecast for this project was overstated, especially at a projected unit cost of $15,000–$30,000 per benefiting customer. We have not included this program as we consider the mobile generation program sufficient to address the issues raised by Ergon Energy's proposal.

Backup reach protection improvement program

In its revised proposal, Ergon Energy resubmitted its backup reach protection program with a forecast of $11.1 million which we did not include in our draft decision. Our final decision maintains this outcome as we did not find sufficient evidence to support the project's prudency. Ergon Energy has since clarified which NER requirements it is expected to comply with (particularly clause S5.1.9 of the NER). However, after assessing its business case, we do not agree that further expenditure outside of its existing base operating expenditure is needed to comply with the NER requirements.[48]

Ergon Energy stated that "24% of our network was identified as having inadequate backup protection".[49] This number is unusual as we consider ongoing management of faults should be an inherent part of network planning and/or group activities, which is generally funded through base operating expenditure. Moreover, fault levels change slowly on a network as they are a function of network augmentation, configuration and the development of loads/generation across the whole network. As fault level management is a generally slow-moving issue managed through existing processes, we would not expect that up to 24% of its

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46 Ergon Energy, *5.5.14 Business Case New Mobile Generation*, January 2024, p 6.

47 AER, *Draft Decision Attachment 5 - Capital Expenditure*, September 2024, pp. 69–70.

48 Ergon Energy, *5.6.03 Business Case Distribution Feeder Backup Protection*, November 2024, p 6.

49 Ergon Energy, *5.6.03 Business Case Distribution Feeder Backup Protection*, November 2024, p 7.

network would exceed the fault level, or that existing protection arrangements would be inadequate to protect the network. We also found that several other aspects of Ergon Energy's business case lacked sufficient explanation on the project's scope, timing, how it derived its costs and evidence of actual field testing. On a proposal level, Ergon Energy did not provide substantiative information to explain the fault level or demonstrate why addressing it should be funded through additional capex.

In terms of the NER requirements, we found that Ergon Energy has certain obligations it needs to fulfill. Clause S5.1.9(c) of the NER, when read together with clause S5.9.1(f)), requires Ergon Energy to provide sufficient back-up protections systems to ensure that any fault on its distribution network is automatically disconnected within a time that would not damage any part of the power system. If there are parts of Ergon Energy's network where there is no backup protection provided (or insufficient backup protection provided), Ergon Energy may be failing to comply with clause S5.1.9(c). Failure to comply with clause S5.1.9(c) would also affect its compliance with its primary obligation in clause 5.2.3(b)(1) of the NER, which requires a Provider to comply with power system performance and quality of standards described in Schedule 5.1. We acknowledge that Ergon Energy's program does focus on addressing areas where fault current ratings are exceeded, consequently demonstrating that a backup protection issue may exist. However, we consider Ergon Energy has not provided any substantive evidence in its revised proposal to support the need to fund this project through means outside of its existing routine operating expenditure. As such, we have maintained our decision to exclude Ergon Energy's backup protection program from our forecast augex.

OTE Zetron continuous improvement program

We have not included Ergon Energy's $0.5 million OTE Zetron program in our total augex forecast as we found it to be part of a systematic issue applying to operational technology programs where benefits were materially overstated. In response to our information request, Ergon Energy outlined its benefits calculation that it derived from the VCR and specifically tied the augex project to its equivalent repex program.[50] Section A.1.3 details our reasoning for why we have not accepted the NPV of Ergon Energy's operational technology programs. As the OTE Zetron program's continuous activities are part of the proposed Zetron replacement, we do not consider that Ergon Energy's basis for the project would be reasonably efficient.

50 Ergon Energy, *IR#072 Ergon Response*, January 2025, p 12.

Glossary

Term	Definition
AER	Australian Energy Regulatory
augex	augmentation expenditure
capex	capital expenditure
CBRM	Condition Based Risk Management
CCP30	Consumer Challenge Panel
CER	customer energy resources
CTG	clearance to ground
CTS	clearance to structure
DNSP or distributor	Distribution Network Service Provider
EQL	Energy Queensland Limited
ICT	information and communication technologies
kN	kilonewton
NEL	National Electricity Law
NEO	National Electricity Objective
NER	National Electricity Rules
NPV	net present value
OTE	operational technology environment
Provider	Network Service Provider
repex	replacement expenditure
RRG	EQL’s Reset Reference Group
SCADA	supervisory control and data acquisition
SCS	standard control service