Draft Decision

Ergon Energy Electricity Distribution Determination 2025 to 2030

(1 July 2025 to 30 June 2030)

Attachment 5
Capital Expenditure

September 2024

AUSTRALIAN ENERGY REGULATOR

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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, to maintain the safety, reliability, quality, and security of its network, and to contribute to achieving the targets for reducing Australia's greenhouse gas emissions (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, cost inputs, and other relevant 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 of consumers in the long term (as required under the National Electricity Objective (NEO)).[4]

The *AER's capital expenditure assessment outline* explains our and distributors' obligations regarding capex 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]

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.

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

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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 Electricity 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.

Ex-post assessment

Our capex framework also sets out the assessment process where a distributor overspends the total capex forecast in the ex-post period.[7] The ex-post period comprises the first three years of the current regulatory control period and the last two years of the preceding regulatory control period.[8] For Ergon Energy, the ex-post period is 2018-23. This differs from the period covered by clause 6.12.2(b) of the NER and for the Capital Expenditure Sharing Scheme (CESS) benefit/penalty calculation, which for Ergon Energy is the current regulatory control period, 2020-25.

Once we have determined that a distributor has overspent its forecast capex in the ex-post period, we can exclude capex incurred during the ex-post period that does not reasonably reflect the capex criteria from the regulatory asset base (RAB).[9]

Assessment approach

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

- AER's Expenditure Forecast Assessment Guidelines[10]
- Regulatory Investment Test for Distribution and Transmission (RIT-D and RIT-T) Guidelines[11]
- AER's Asset Replacement Industry Note[12]
- AER's Information and Communication Technologies (ICT) Guidance Note[13]

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7 NER, cl. S6.2.2A.

8 NER, cl. S6.2.2A(a1).

9 NER, cl. S6.2.2A(f).

10 AER, *Expenditure Forecast Assessment Guideline for Distribution*, August 2022. The legal requirements of the AER under the NEL and the NER in assessing capex are outlined in section 2.1.

11 AER, *RIT-T and RIT-D application guidelines (minor amendments) 2017,* September 2017.

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

13 AER, *AER publishes guidance on non-network ICT capital expenditure assessment approach,* November 2019.

- AER, Capital Expenditure Incentive Guideline for Electricity Network Service Providers.[14]

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.[15]

Our draft decision has been based on the information before us at this time, 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
- 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 being Ergon Energy's overspend in repex and forecast repex, aspects of Ergon Energy and Energex's forecast augex, Ergon Energy and Energex's forecast for cyber security. EMCa's report will be released with our draft decision.

5.1 Draft decision

Our draft decision is that we are not satisfied that Ergon Energy's capex overspend in the ex-post period (2018-23 period) of $1,195.0 million ($2024–25) reasonably reflects the capex criteria (in particular, we are not satisfied that it reasonably reflects the prudent and efficient costs to meet the capex objectives). Our substitute forecast is $598.8 million, which is 50.0% below Ergon Energy's actual capex overspend. Table 5.1 provides a breakdown by category of our ex-post draft decision. As can be seen, our position is driven mostly by a reduction of 45.3% to Ergon Energy's repex overspend in the 2018-23 period.

Table 5.1 AER Draft Decision: Ergon Energy Ex-post review ($ million, $2024–25)

Capex category	AER Forecast 2018–23	Ergon Energy actuals 2018–23	Difference from forecast (assessed overspend)[b]	Proposed overspend to include in the opening RAB
Augex	400.2	228.4	-171.8	-171.8
Net connections	270.7	314.9	44.2	44.2
Repex	989.6	2221.5	1231.9	674.0
ICT[a]	132.7	246.3	0.0	0.0
Property	99.8	151.5	51.7	51.7
Fleet	185.6	129.1	-56.5	-56.5
Plant & Equipment	33.6	34.7	1.1	1.1
Capitalised overheads	942.1	1036.5	94.4	56.1

14 AER, *Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, April 2023.

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

Total capex	**3054.3**	**4362.9**	**1195.0**	**598.8**

Source: Ergon Energy and AER analysis.
Note: (a) As Ergon Energy proposes to exclude its ICT overspend from the opening RAB, it is also excluded as part of our assessed capex overspend.
(b) Due to the underspend in augex (-$171.8 million) and fleet ($-56.5 million), the net overspend of $1195.0 million is lower than the total repex overspend of $1231.9 million.

Our draft decision is also to not accept Ergon Energy's proposed total forecast capex of $5,704.8 million ($2024–25) for the 2025-30 period 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 to meet the capex objectives). Our substitute forecast is $4,188.1 million which is 26.6% below Ergon Energy's forecast. We consider this forecast will provide for a prudent and efficient service provider in Ergon Energy's circumstances to meet the capex objectives. Table 5.2 outlines our substitute estimate of forecast capex and compares this to Ergon Energy's proposed forecast capex.

Table 5.2 AER's draft decision on Ergon Energy's total net capex forecast for 2025–30 ($ million, $2024–25)

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
Ergon Energy's proposal[a]	1117.6	1117.9	1127.8	1145.4	1196.2	5704.8
AER's draft decision	822.9	815.1	827.7	841.0	881.4	4188.1
Difference ($)	**-294.7**	**-302.8**	**-300.0**	**-304.4**	**-314.8**	**-1516.7**
Difference (%)	**-26.4%**	**-27.1%**	**-26.6%**	**-26.6%**	**-26.3%**	**-26.6%**

Source: Ergon Energy and AER analysis. Numbers may not sum due to rounding.
Note: (a) Ergon Energy's proposal differs from its proposal documents as it submitted an updated capex model on 28 June 2024. It originally proposed net capex of $5783.0.

At this stage, we see our draft decision as a placeholder. There may be other information not currently available to us which could mean a more optimal estimate can be achieved. In this regard, we encourage Ergon Energy to engage with us prior to its submission of its revised proposal to discuss what further information is available to support its proposal.

5.2 Ergon Energy's proposal

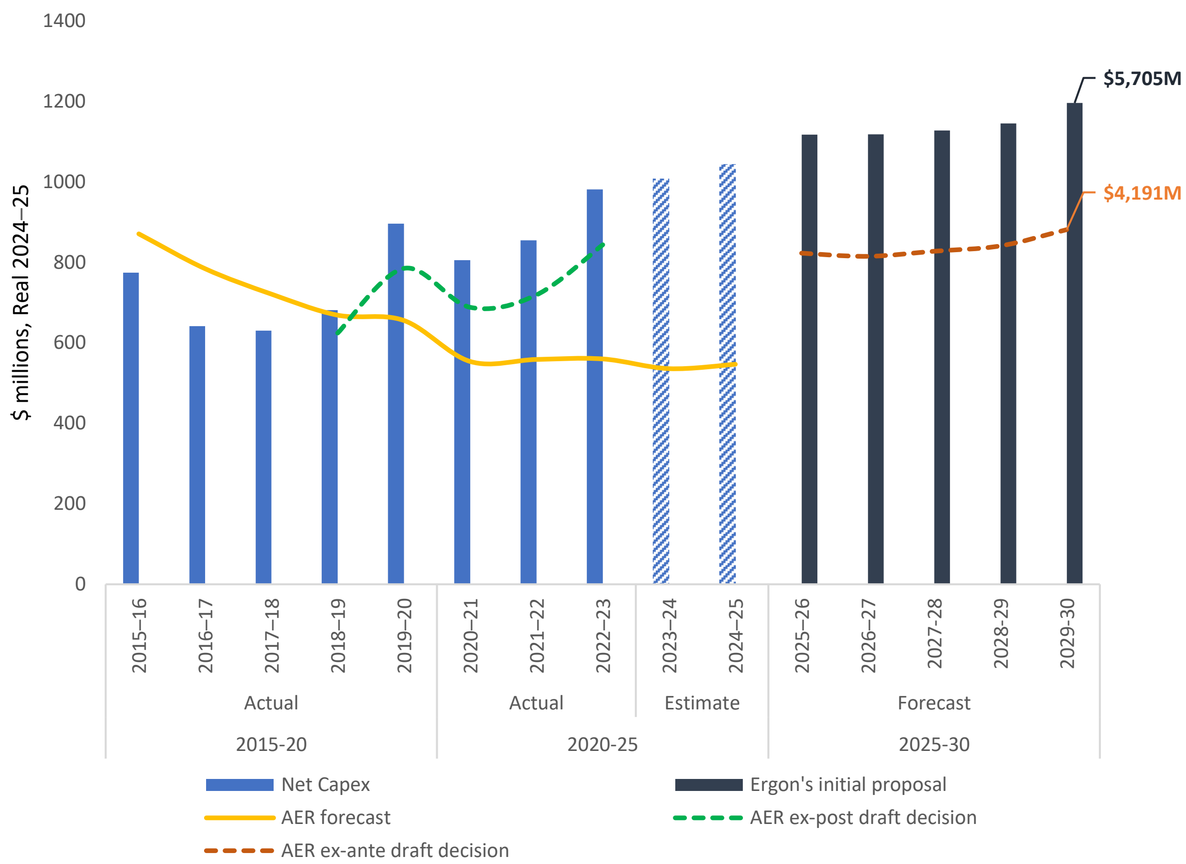
Ergon Energy overspent by $1,195.0 million (or 39.1% higher) relative to the AER's capex forecast in the ex-post period (2018–23 period). The largest areas of overspend are in poles ($341.3 million), switchgear ($268.0 million), pole top structures ($234.2m) and transformer assets ($207.4 million).

Ergon Energy is proposing a forecast net capex of $5,704.8 ($2024–25) over the 2025–30 period. This is $78.2 million lower than in its initial proposal as it submitted an updated capex model on 28 June 2024 with some amendments to its forecast.[16]

[16] Ergon Energy, *Amendments to Ergon Energy Network's 2025–30 Regulatory proposal SCS Capex model*, June 2024.

Figure 5.1 outlines Ergon Energy's historical capex trend, the overspend in the ex-post period, its proposed forecast for the 2025–30 regulatory control period, and our draft decision.

Figure 5.1 Ergon Energy's historical and forecast capex ($ million, $2024–25)



Source: Ergon Energy's proposal and AER analysis.

Note: Capex is net of asset disposals and capital contributions. As Ergon Energy proposes to exclude its ICT overspend from the opening RAB, we have excluded its ICT overspend from its net capex for years 2020–21 to 2022–23.

Figure 5.1 shows that Ergon Energy proposes to further increase its already elevated level of capex in the ex-post period into the forecast period. Figure 5.1 also shows that our draft decision on the ex-post review accepts some of Ergon Energy's overspend. Our draft decision on Ergon Energy's forecast capex trend is relatively in line with our draft decision on the ex-post review.

We also note that the estimates in the last two years of the current period are higher than the first three years in the current period. This would suggest that another ex-post review is a possibility in Ergon Energy's next revenue determination.

5.2.1 Ergon Energy's overspend in the ex-post period (2018–23 period)

Table 5.3 provides a breakdown of Ergon Energy's capex overspend by capex category. As can be seen, the majority of the overspend has been in repex where actual expenditure is 124.5% higher than the AER's forecast in the ex-post period. Other contributors to the overspend include connections, property, ICT and capitalised overheads. Ergon Energy states that it does not intend to recover the expenditure on ICT capex above the amount that was included in the AER's forecast for the ex-post period.[17] As Ergon Energy proposes to exclude its ICT overspend from the opening RAB, it is also excluded as part of our assessed capex overspend, as reflected in Table 5.3.

Table 5.3 Ergon Energy's overspend by category ($ million, $2024–25)

Capex category	AER Forecast 2018–23	Ergon Energy actuals 2018–23[a]	Ergon Energy overspend ($)	Ergon Energy overspend (%)
Augex	400.2	228.4	-171.8	-42.9%
Net connections	270.7	314.9	44.2	16.3%
Repex	989.6	2221.5	1231.9	124.5%
ICT[b]	132.7	246.3	0.0	N/A
Property	99.8	151.5	51.7	51.8%
Fleet	185.6	129.1	-56.5	-30.4%
Plant & Equipment	33.6	34.7	1.1	3.3%
Capitalised overheads	942.1	1036.5	94.4	10.0%
Total capex	**3054.3**	**4362.9**	**1195.0**	**42.8%**

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

Note: (a) During the 2020–25 period, Ergon Energy re-categorised $40.9 million of CTG/CTS expenditure from repex to augex. For a like for like comparison with our 2018–23 AER forecast, we have re-categorised this $40.9 million back to repex.
(b) As Ergon Energy proposes to exclude its ICT overspend from the opening RAB, it is also excluded as part of our assessed capex overspend.

5.2.2 Forecast capex for the 2025–30 period

Table 5.4 provides a breakdown of Ergon Energy's capex proposal for the 2025-20 period in more detail. As Table 5.4 shows, Ergon Energy is forecasting an 18.5% increase in its total capex forecast relative to actual/estimates in the current period. This is driven by forecast increases relative to the current period in almost all capex categories except for ICT. We note that forecast repex contributes the most to the total capex forecast. Ergon Energy's repex forecast is 11.8% higher than the current period although we observe that the current period repex is already elevated given it is 125.6% higher than the AER's forecast for the 2020-25 period.

Table 5.4 Ergon Energy's capex category forecast compared with actual/estimated capex in 2020–25 ($ million, $2024–25)

Capex category	Ergon's 2020–25 capex[b]	Ergon's 2025–30 forecast[a]	Change from 2020–25	Contribution to increase in net capex	Proportion of total forecast capex
Repex	2432.4	2718.8	11.8%	32.1%	47.7%
Resilience	N/A	53.1	N/A	N/A	0.9%
Augex	358.0	513.2	43.3%	17.4%	9.0%
Connections	321.0	321.2	0.1%	0.0%	5.6%

[17] Ergon Energy, *2025–30 Regulatory Proposal*, January 2024, p. 87.

Fleet	170.6	243.0	42.5%	8.1%	4.3%
Property	141.9	174.7	23.1%	3.7%	3.1%
Cyber security	N/A	53.4	N/A	N/A	0.9%
ICT	400.1	258.8	-35.3%	-15.9%	4.5%
CER integration	N/A	63.0	N/A	N/A	1.1%
Other non-network	27.2	31.7	16.5%	0.5%	0.6%
Capitalised overheads	986.3	1316.1	33.4%	37.0%	23.1%
Total capex (excluding capcons)	**4837.5**	**5746.9**	**18.8%**		
less asset disposals	-23.6	-42.1	78.4%		
Net capex	**4813.9**	**5704.8**	**18.5%**		

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

Note: (a) Ergon Energy's proposal differs from its proposal documents as it submitted an updated capex model on 28 June 2024. It originally proposed net capex of $5783.0.

(b) Consistent with how we assessed CTG/CTS capex in the ex-post review, we have re-categorised $80.8 million of Ergon Energy's actual/estimated 2020–25 period CTG/CTS capex from augex to repex.

5.3 Reasons for draft decision on Ergon Energy's ex-post capex

Our draft decision is to not accept Ergon Energy's proposal to include $1,195.0 million of its capex overspend into the opening RAB for the 2025–30 period. We did not find that its total capex overspend was prudent and efficient and have instead included $598.8 million which is 50.0% below Ergon Energy's proposal. As outlined below, we consider this is a placeholder decision based on the available information at this stage.

Assessment framework

We reviewed Ergon Energy's capex overspend in line with the ex-post staged review process set out in the AER's Capital Expenditure Incentive Guideline for Electricity Network Service Providers.[18] The first stage considers whether the overspend is significant at the total forecast capex level. If we consider that the Distribution Network Service Provider (DNSP) capex overspend warrants further assessment, stage 2 involves a deeper bottom-up review of the capex overspend.

Overall, we have assessed that, at the total forecast capex level, Ergon Energy's total capex overspend of $1,195.0 million is significant. As such, we consider that further assessment is warranted.

We found that the repex category contributes the most to the overspend. The overspend in repex of $1,231.9 million represents 86.6% of the capex categories that have an

18 AER, *Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, April 2023, pp. 13-15.

overspend.[19] Therefore, at stage 2 of the ex-post review process, we have undertaken a bottom-up review of the overspend in repex. In the other areas of overspend - that is, in property, ICT and connections - we undertook a high-level review and found the capex incurred to be within a reasonable range.

In undertaking our bottom-up review, we had regard to all the information before us. This includes the advice from our independent engineering/technical consultant, EMCa, who we engaged to undertake its own ex-post review in parallel with our ex-post review.

We placed the greatest weight on information provided by Ergon Energy. We had regard to Ergon Energy's regulatory proposal, including all supporting information such as models, data, business cases, consultant reports and cost benefit analysis. We issued Ergon Energy numerous information requests (60+) and held face-to-face meetings about information gaps, data errors, and further detail given the lack of information in its proposal.

We and our consultant, EMCa, also engaged extensively with Ergon Energy throughout our assessment process. This included extensive face-to-face deep dive sessions attended by Ergon Energy's subject matter experts including its senior engineers, asset managers, and regulatory managers.

We also had regard to stakeholder comments in response to our Issues paper. We also met with the Electrical Safety Office (ESO) to discuss any comments it had about Ergon Energy's proposal.

Overall, we found that Ergon Energy's supporting documentation contained significant information and data gaps, data discrepancies and reconciliation issues, and lack of detail and sufficient reasoning to substantiate the prudency and efficiency of its proposal. EMCa came to the same conclusion.

Due to the information gaps and Ergon Energy's inability to provide further detailed information and evidence, we explored other avenues of investigation. This included a review of the Regulatory Information Notice (RIN) data, testing Ergon Energy's performance against the repex model, and other comparative benchmarking exercises.

Our findings

Based on the information before us, we consider that some of Ergon Energy's overspend was justified given the circumstances at the time of its investment decision.

At this stage, Ergon Energy has not provided us with sufficient evidence that the total overspend reflects the decisions of a prudent and efficient operator. Our findings in the three primary drivers for the repex overspend are summarised below. Appendix A provides further details on our reasons for not accepting Ergon Energy's overspend.

Consistent with the NEO, in making our draft decision we have had regard to the need for Ergon Energy to operate a safe network. In particular, our draft decision includes:

- Accepting some of the overspend on pole asset replacement by including a 'catch up' period using a longer time series

[19] As the net overspend of $1,195.0 million includes the underspend in augex and fleet which is higher than $1,231.9 million, this percentage calculation is only based on the capex categories that have overspend and assessed as part of our ex-post review (i.e. excluding the augex and fleet underspend).

- Accepting all the actual and proposed forecast conductor asset replacement
- Accepting all the actual and some of the proposed forecast stand-alone (targeted) pole top structure asset replacement
- Accepting all the actual and proposed forecast stand-alone (targeted) service asset replacement
- Accepting all the actual and proposed defect volumes for the clearance programs.

Based on our discussion with the ESO and the information and evidence submitted to us to date, it is our understanding that these are the key areas of repex where there may be safety concerns.

We found no emerging safety risk related to transformers and switchgears assets, which is the key area of the repex overspend.

Poles overspend

Ergon Energy overspent by $341.3 million on pole assets, which accounts for 27.7% of the total repex overspend.

We found a genuine need for Ergon Energy to overspend on some its pole repex during the ex-post period. In particular, we are cognisant that Ergon Energy in 2019–20 exceeded the Electrical Safety Code of Practice (ESCOP) three-year moving average pole failure rate of 1 per 10,000 poles.[20]

However, we consider that Ergon Energy's response of adopting Energex's pole management practices and standards has resulted in higher pole replacement than is efficient. Energex, as an urban network, has an inherently different risk profile compared to Ergon Energy's predominately rural network. This is because, when compared to Ergon Energy's network, Energex's higher customer density network consists of higher demand per line, which results in more customers losing supply during asset failures. Safety risks are also higher in an urban network when compared to a predominantly rural network due to the higher probability of public exposure from assets being in closer proximity to urban centres.

While Energex's pole practices might be appropriate for Energex's network to maintain its overall safety and reliability performance, applying Energex's practices and standards to Ergon Energy has led to unnecessarily high costs to maintain asset performance. In addition, we note that Energex's current pole performance is outperforming the ESCOP's outlined failure rate of 1 per 10,000 poles by about 400% (i.e. it had a failure rate of 1 per 48,000 poles in the 2018-23 period).

There is also a lack of evidence to support the prudency and efficiency of the higher pole expenditure at the time of the investment. Consistent with good industry practice, we would expect a prudent and efficient operator to undertake a review like a root cause analysis to determine the underlying problem with its poles and therefore target the replacement. The lack of a root cause analysis was also raised by the CCP.[21] We would encourage Ergon Energy to provide us with evidence of a root cause analysis if this was undertaken.

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20 Since the changes in Ergon Energy's pole management practices in early 2019, we observed a reduction in the annual pole failures in 2020–21 and 2022–23.

21 CCP30, *Advice to the AER regarding the Energex and Ergon Energy regulatory proposals 2025–30*, May 2024, p. 12.

Ergon Energy also did not provide evidence that it tested the outcomes from applying Energex's pole management practices and standards, and business cases were not undertaken to support Ergon Energy's revised poles forecast. For example, Ergon Energy did not undertake a Regulatory Investment Test – Distribution (RIT-D) or equivalent analysis to test the costs and benefits of different options to address the increase in unassisted pole failures.

DNSPs are required to apply the RIT-D in accordance with cl 5.17.3 of the NER, unless one of the exceptions in cl 5.17.3(a) applies.

Our position is that a RIT-D will normally be required for a program to replace multiple assets of the same type, where the program results from changes to engineering criteria for asset replacement and its cost exceeds the relevant financial threshold. We clarified this position in a Compliance Bulletin in 2021.

It is therefore possible that when Ergon made modifications to its pole serviceability criteria, its failure to apply the RIT-D in accordance with cl 5.17.3 may have been a breach of the NER, although we note these modifications pre-dated the AER's 2021 Compliance Bulletin.

We intend to address Ergon's pole replacement through this regulatory process rather than compliance channels but will continue to engage with all distributors to foster compliance with the NER and to ensure our expectations as set out in its Compliance Bulletin are understood.

Absent the above type of evidence, we do not have confidence that Ergon Energy's investment in higher pole expenditure is prudent and efficient.

Opportunistic replacement

Ergon Energy overspent by approximately $544.0 million on opportunistic replacement, which accounts for 44.2% of the total repex overspend.[22]

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 aging cross-arm or conductor during a pole replacement. However, Ergon Energy's opportunistic replacement makes up to 44.2% of the total repex overspend with larger assets like transformers and switchgears making up to 51.9% of these opportunistic replacements. We found no emerging safety risk related to these assets.

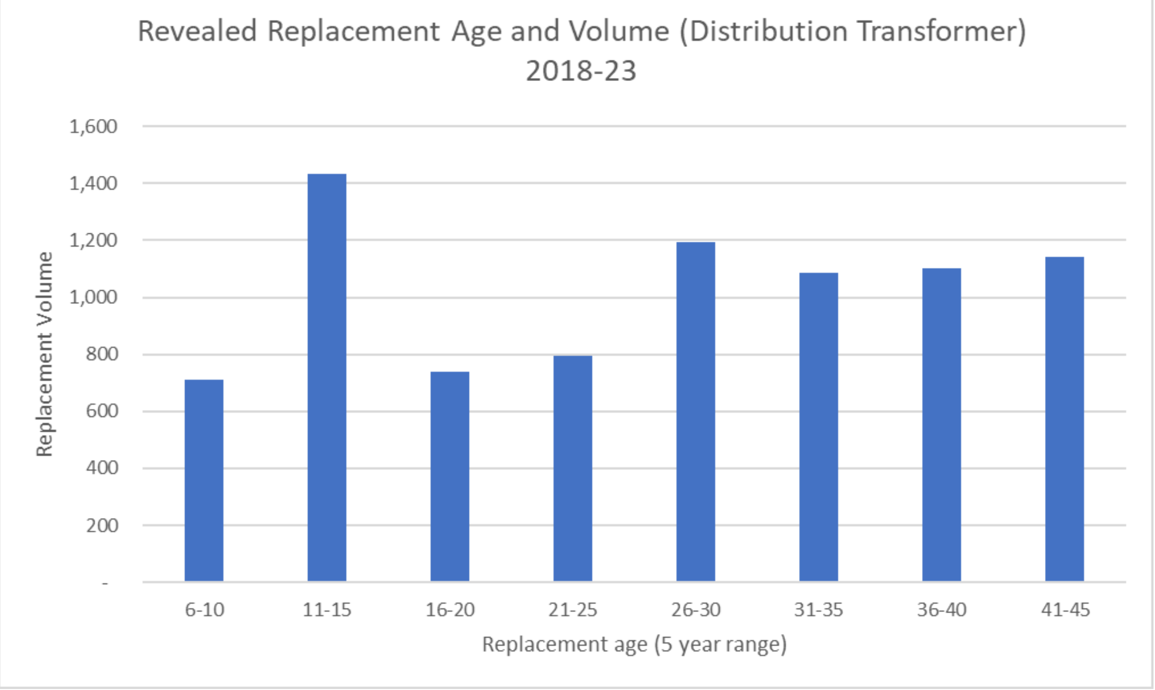
Our review of Ergon Energy's supporting material is that, in many instances, opportunistic replacement has not been cost effective, and there is a lack of evidence to support the prudency and efficiency of these investments.

We found that Ergon Energy has been replacing assets much earlier than the end of their economic life, where there are no emerging or existing defect issues, or the defects are identified as low priority. We also found evidence that replacing these assets earlier is

[22] While it is possible some defective assets are replaced as part of opportunistic replacement, Ergon Energy did not provide sufficient information for us to verify these assets.

against Ergon Energy's own business rules for opportunistic replacement. For example, Figure 5.2 shows the revealed replacement age of Ergon Energy's distribution transformers. As can be seen, the revealed age of replacement is much earlier than the typical economic and design life of a transformer of 45 to 55 years.

Figure 5.2 Revealed Age of Replacement of Distribution Transformers



Source: AER analysis

More generally, we observe that Ergon Energy's inefficiently higher volumes of opportunistic replacement of these assets is likely to result in greater emission levels, which is not in the long-term interests of consumers.

Clearance-to-Ground/Clearance-to-Structure (CTG/CTS)[23]

We acknowledge Ergon Energy's regulatory obligations in relation to CTG/CTS in the *Electrical Safety Regulation 2013* (Qld). In particular, we appreciate that Ergon Energy must address breaches of its clearance limits. We also met with the ESO who indicated that a few improvement notices had been served to Ergon Energy in recent years about its CTG/CTS program.

We accept that Ergon Energy has legislative obligations to address breaches of its clearance limits and have accepted the incurred conductor clearance volumes in the ex-post period.

However, we found that the primary driver of the overspend has been an almost doubling of unit rates. Based on the information submitted by Ergon Energy, we found that about half its CTG defects have a clearance gap of less than 20cm. In this respect, we consider that Ergon Energy did not act in a prudent and efficient manner in choosing the considerably more expensive option of replacement compared to the lower cost industry-accepted practice of

[23] During the 2020–25 period, Ergon Energy re-categorised $40.9 million of CTG/CTS expenditure from repex to augex. For a like for like comparison with our 2018–23 AER forecast, we have re-categorised this $40.9 million back to repex for our assessment purposes.

re-tensioning (or a combination of re-tensioning and staking), particularly for defects that had a clearance gap of less than 20cm.

High-level comparisons

We also undertook a high-level review of Ergon Energy's reliability performance over time and compared Ergon Energy against other DNSPs (all NSW and Victorian DNSPs) across some key metrics such as average pole and other asset ages as well as replacement rates. Overall, we found that Ergon Energy did not benchmark well against other DNSPs when comparing age and replacement rates, which is concerning when we consider that its reliability metrics are performing well. In particular, we found:

- Ergon Energy's System Average Interruption Frequency Index (SAIFI) results indicate improved asset performance (that is, fewer failures), while its whole-of-network SAIFI is trending downwards reflecting improved rural performance over time
- Ergon Energy's pole population is relatively young especially compared to the other DNSPs. This is also the case across all distribution asset classes
- Ergon Energy was replacing all distribution asset classes sooner in the ex-post period compared to other DNSPs.

Our draft decision is a placeholder

We see our draft decision as a placeholder. There may be other information not available to the us which could mean a more optimal estimate can be achieved. In section A.3.1.3, we set out the information and data gaps we have identified in Ergon Energy's proposal and would expect this to be addressed in its revised proposal. We would also expect that Ergon Energy genuinely engage with its stakeholders about its revised proposal. In particular, it should be transparent about whether the overspend has addressed expected risks, which was raised as a concern by the CCP[24] and RRG[25] in their submissions to the Issues Paper.

Due to our concerns with the information and data provided to us, we have had to explore other avenues to derive an alternative estimate. We have explored other approaches including bottom-up analysis, backcasting using the repex model and other forms of benchmarking analysis. However, 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 overspend estimate for Ergon Energy's poles overspend is based on benchmarking Ergon Energy's pole replacement rate against Essential Energy.

We undertook comparative analysis between Ergon Energy and other DNSPs and found Essential Energy as the best available business to compare with Ergon Energy. This is because Essential Energy faces similar challenges with the age and conditions of its pole population as Ergon Energy. In particular, we found that Ergon Energy and Essential Energy have similar pole composition and operating environment factors (similar rainfall and humidity levels) that are likely to impact age and condition of their pole populations. For

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24 CCP30, *Advice to the AER regarding the Energex and Ergon Energy regulatory proposals 2025–30*, May 2024, p. 12.

25 RRG, *Submission on Ergon Energy and Energex electricity distribution regulatory proposals 2025–30 and the Australian Energy Regulator's Issues Paper*, May 2024, p. 4.

example, both businesses have similar customer line density (5.5 versus 5.2) and relative proportion of timber, steel and concrete poles. In comparison, Energex's customer line density is more than 6 times higher (34.2 versus 5.5) with less than half the timber pole population (405,578 versus 871,347). While Essential Energy has 29.1% more timber poles compared to Ergon Energy, it also has 28.2% more customers. In comparison, Energex's has 111.7% and 65.2% more customers compared to Ergon Energy and Essential Energy respectively.

In applying this approach, we have erred on the conservative side as we did not benchmark Ergon Energy against other potential comparators such as AusNet and Powercor which have a regional component to their service area. We note that Ergon Energy would have performed worse if we included these businesses because of their longer replacement lives. We also did not take account of Ergon Energy's younger asset lives in our benchmarking and did not pursue concerns raised by EMCa about Ergon Energy's inefficiently high unit costs in some areas[26] and the overspend in the stand-alone programs for pole top structures and services.[27]

We also note that our alternative overspend estimate includes an additional amount for the useful life of the asset replaced even when the asset has been replaced earlier than efficient. We consider our approach incentivises prudent and efficient decision-making as it ensures that Ergon Energy is not penalised going forward for inefficient investments made in the ex-post period.

5.4 Reasons for draft decision on Ergon Energy's forecast capex for 2025–30

We reviewed Ergon Energy's capex drivers, programs and projects to inform our view on a total capex forecast that reasonably reflects the capex criteria. We conducted top-down analysis such as examining trends and forecast costs compared with historical capex, and inter-relationships between cost categories. To complement this, we conducted a bottom-up analysis of Ergon Energy's major programs and projects.

Our capex assessment focused primarily on the material capex categories that either represented a significant uplift in expenditure, had stakeholder interest, or are new and evolving areas such as CER and resilience. For capex that was relatively small and forecast using established modelling approaches and inputs in line with our expectations, we did not need to undertake a more detailed analysis of the individual programs and projects. Our draft decision is reflective of this approach as set out below in Table 5.5.

Further, in considering the scope of our review, we had regard to how Ergon Energy has performed against the Better Resets Handbook expectations for capex.[28] Our assessment against each expectation is set out in Table 5.5. As can be seen, Ergon Energy did not

26 EMCa, *Ergon Energy 2025/26 to 2029/20 Regulatory Proposal, Review of Aspects of Proposed Expenditure*, September 2024, pp. 78-80.

27 EMCa, *Ergon Energy 2025/26 to 2029/20 Regulatory Proposal, Review of Aspects of Proposed Expenditure*, September 2024, p. 66.

28 AER, *Better Resets Handbook – Towards Consumer Centric Network*, December 2021, pp. 19–23.

satisfy any of the Better Resets Handbook expectations for capex. We have therefore undertaken a bottom-up review in most capex categories.

Table 5.5: Ergon Energy's performance against the capex expectations

Capital expenditure expectations	AER position
1. Top-down testing of the total capex forecast and at the category level	Ergon Energy has not satisfied this expectation because: • Its total capex forecast is 18.5% above 2020-25 period spend. • Step up in its total forecast relative to current period spend is in some recurrent expenditure like repex and fleet. • Step up relative to the 2020-25 period is in most capex categories. • Ergon Energy has materially overspent by 43% in the ex-post period.
2. Evidence of prudent and efficient decision-making on key projects and programs	Ergon Energy has not satisfied this expectation because: • We found significant information gaps and a lack of justification of the prudency and efficiency of most of forecast at the category level.
3. Evidence of alignment with asset and risk management standards	Ergon Energy has not satisfied this expectation because: • While there have been improvements Ergon Energy's asset management practices, we found a number of incidences where it did not align with good industry standards.
4. Genuine consumer engagement on capex proposals	Ergon Energy has not satisfied this expectation because: • Submissions received about Ergon Energy's engagement on its capex proposal have been critical that there was little evidence that Energy Queensland had considered consumer feedback in its proposals. • RRG notes that engagement breadth and depth were limited small parts of capex (some ICT, property, EVs, DER enablement). The RRG concluded that the engagement fell well short of what was expected under the AER's Better Resets Handbook and what RRG members had observed in other recent electricity distribution resets. The RRG considers that there is little benefit in further engagement.

As part of our draft decision, we have been able to accept a number of categories of proposed capex. This includes connections, cyber security and CER integration. In addition, we have accepted the following elements of the repex forecast as set out in B.1.3.2:

- conductor asset replacement
- the stand-alone (targeted) service asset replacement
- the proposed defect volumes for the CTG/CTS programs.

We have not accepted Ergon Energy's forecast in full because we found insufficient information in support of its forecast in repex, augex, resilience, fleet, property, ICT and capitalised overheads. Based on the information before us, we are satisfied that our alternative forecast of total capex of $4,188.1 million (a reduction of 26.6% from Ergon Energy's forecast) is reasonable and sufficient for Ergon Energy to maintain the safety, reliability and security of electricity supply to its network and contribute to achieving emissions reduction targets. To provide guidance for Ergon Energy in preparing its revised proposal, we have noted information gaps and areas for improvement for forecasting and supporting information.

The section below outlines findings from our top-down and bottom-up review.

Top-down perspective

We made a number of observations at a top-down level which indicate that Ergon Energy's forecast capex is not prudent and efficient. These are set out below.

We found a lack of supporting material to demonstrate prudency and efficiency in most of the capex categories, including information gaps, and limited evidence to support key inputs

There is a lack of information to support the prudency and efficiency of Ergon Energy's forecast repex, augex, resilience, fleet, property and capitalised overheads. For repex, Ergon Energy proposes to continue its current poles program into the forecast period, proposing further increases to its total pole replacement expenditure beyond its historical levels. Ergon Energy does not provide sufficient evidence to demonstrate that its historical expenditure is a reasonable proxy for prudent and efficient expenditure in the forecast period, especially given the concerns we have about its expenditure in the ex-post period.

We also found information gaps and a lack of evidence to support key inputs in a number of cases. For instance, for its ICT proposal, Ergon Energy provided very high level descriptions of the scope of works for each investment. Some investment had no quantified benefits, and where there were qualitative benefits, Ergon Energy provided little detail even when we requested further information. We also found that the costs of the ICT initiatives were hard-coded so we were not able to assess cost efficiency.

Material data discrepancies and data challenges, and delay of critical information for review which reduced our confidence on the robustness of the cost build-up of the forecast

There were difficulties in reconciling between projects and programs with the RIN and Ergon Energy's documentation. We also found instances of incorrect modelling techniques and escalation assumptions.[29]

EMCa also raised concerns about the delay of critical information provided to it as part of its review. In particular, it noted that information to explain Ergon Energy's forecast repex was provided to it 6 months after the submission of its regulatory proposal with the reasons for withholding this information unclear:[30]

> In discussion with the AER, we asked a further extensive set of questions with the objective of understanding the artefacts that Ergon had relied upon in developing the expenditure forecasts, including the models it had prepared. We were provided this information on 10 June, nearly six months after lodgement of the RP to the AER, and we have sought to take this into account in this report. In the process of obtaining this information, and for reasons that are unclear to us, we learned that Ergon had earlier made a decision to withhold this information from its submission to the AER.

Inappropriate adoption of Energex's asset management practices.

With the integration of Ergon Energy and Energex, there are a number of programs where supporting material is similar as it has been developed centrally through Energy Queensland.

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29 EMCa, *Ergon Energy 2025/26 to 2029/20 Regulatory Proposal, Review of Aspects of Proposed Expenditure*, September 2024, p. 32.

30 EMCa, *Ergon Energy 2025/26 to 2029/20 Regulatory Proposal, Review of Aspects of Proposed Expenditure*, September 2024, p. 86.

We observe that Ergon Energy made changes to its capex forecasting methods aimed at the integration of processes associated with the establishment of Energy Queensland. In this regard, materials such as business cases and models in support of Ergon Energy and Energex's proposals for fleet, ICT, cyber security, resilience and capitalised overheads are similar. But Ergon Energy and Energex's programs differ to reflect the risk profile and operating specifics of each business. For instance, Ergon Energy and Energex plan to procure their fleet needs from the one same supplier, however, the type and number of vehicles differs depending on the risks of each network.

However, we found Ergon Energy did not have regard to its distinctly different risk profile when it adopted Energex's pole standards and practices. This integration and standardisation of methods has contributed to higher forecast expenditure levels for Ergon Energy. As Energex is predominately an urban network and therefore has an inherently different level of risk than the Ergon Energy network, this has resulted in unnecessarily high costs to maintain Ergon Energy's asset performance.

Lack of customer engagement on capex and the proposal does not appear to address affordability, which was identified as the main priority by customers.

Ergon Energy submits that:[31]

> Our engagement, grounded in best practice principles, has been instrumental in refining our plans, ensuring they resonate with the needs and expectations of our customers and adapt to the evolving energy landscape.

However, the RRG and CCP30 observed the lack of engagement on Ergon Energy's capex proposal, with the RRG indicating that it saw little value in further engagement given the very limited scope of engagement to date.

Energy Queensland also states that: 'Our proposal responds to customer concerns about affordability'.[32] However, the CCP30 observes that:[33]

> There is little evidence of how EQL has considered consumer feedback about the proposal, particularly in their core expenditure proposals on the major issue of affordability.

Bottom-up review

Our bottom-up review revealed a lack of information to support the prudency and efficiency of Ergon Energy's forecast in repex, augex, resilience, fleet, property, ICT and capitalised overheads. We have therefore included alternative forecasts for these parts of Ergon Energy's proposal in deriving our alternative estimate of total capex. Table 5.6 sets out our draft decision for Ergon Energy by capex category.

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[31] Ergon Energy, *Overview: Ergon Energy Network Regulatory Proposal for 2025–30*, January 2024, p. 16.

[32] Ergon Energy, *Overview: Ergon Energy Network Regulatory Proposal for 2025–30*, January 2024, p. 20.

[33] CCP30, *Advice to the AER regarding the Energex and Ergon Energy (Energy Queensland) regulatory proposals 2025–30 – Response to the Proposals and Issues Paper*, May 2024, p. 4.

Table 5.6 AER's draft decision by capex category ($million, $2024–25)

Capex category	Ergon Energy's proposal[a]	Forecast assessed[bc]	AER's draft decision	Difference ($)	Difference (%)
Repex	2545.6	2718.8	1844.3	-874.5	-32.2%
Resilience	N/A	53.1	26.8	-26.2	-49.4%
Augex	763.4	513.2	429.2	-84.0	-16.4%
Connections	321.2	321.2	321.2	0.0	0.0%
Fleet	243.0	243.0	210.1	-32.9	-13.6%
Property	174.7	174.7	170.7	-4.0	-2.3%
Cyber security	N/A	53.4	53.4	0.0	0.0%
ICT	288.3	258.8	208.7	-50.1	-19.4%
CER integration	63.0	63.0	63.0	0.0	0.0%
Other non-network	31.7	31.7	31.7	0.0	0.0%
Capitalised overheads	1316.1	1316.1	874.4	-441.7	-33.6%
Total capex (excluding capcons)	**5746.9**	**5746.9**	**4233.5**	**-1513.4**	**-26.3%**
less asset disposals	-42.1	-42.1	-42.1	0.0	
Modelling adjustments			-3.4	-3.4	
Net capex	**5704.8**	**5704.8**	**4188.1**	**-1516.8**	**-26.6%**

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

Note: (a) Ergon Energy's proposal differs from its proposal documents as it submitted an updated capex model on 28 June 2024. It originally proposed net capex of $5783.0.

(b) Our forecast assessed re-categorised capex from Ergon Energy's proposal to align with how we assessed each category. We re-categorised $7.9 million of repex, $16.1 million of augex and $29.4 million of ICT to cyber security, and re-categorised $53.1 million of augex to resilience.

(c) Consistent with how we assessed CTG/CTS capex in the ex-post review, we have re-categorised $181 million of Ergon Energy's proposed CTG/CTS capex from augex to repex.

Table 5.7 summarises, and Appendix B provides further details on, our reasons for not accepting Ergon Energy's forecast, by capex driver. 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 an alternative estimate for total capex where necessary. Our decision on total capex does not limit a regulated business' actual spending.

Table 5.7 Summary of our findings and reasons on forecast capex in the 2025–30 period, by capex driver

Driver	Findings and reasons
Connections	Our draft decision includes Ergon Energy's net connections capex forecast of $321.2 million as part of our total capex forecast. Ergon Energy's connections forecast is similar to the current 2020–25 period net connections capex. Having regard to average unit rates, trend analysis and Queensland Government data (i.e. population growth), we are satisfied with Ergon Energy's proposal. We have provided feedback on Ergon Energy's connections forecasting methodology in the event that Ergon Energy updates its revised proposal connections forecast. This is further discussed in Appendix B.3.

Driver	Findings and reasons
Cyber security	Our draft decision includes Ergon Energy's cyber security forecast of $53.4 million as part of our total capex forecast. Overall, we found that the information provided adequately supported the proposed expenditure. We consider that Ergon Energy has appraised the cyber security landscape and has a good understanding of its compliance obligations under the *Security of Critical Infrastructure (*SOCI) Act[34] and how to meet them. Ergon Energy has selected the appropriate preferred option based on the risk-costs and its cost forecasting methodology and cost forecast for its preferred option is reasonable. We found some issues with its analysis that we encourage Ergon Energy to consider in future processes. In particular, EMCa found the CBA in support of the cyber security capex contained errors, overestimated and underestimated cost impacts, and there was a lack of detail in some parts of the analysis.
CER integration	Our draft decision includes Ergon Energy's capex forecast of $63.0 million to integrate consumer energy resources (CER) as part of our total capex forecast. We consider that Ergon Energy's CER strategy is generally sound and measured. In particular, we consider that maximising existing hosting capacity by prioritising dynamic connection investments over increasing hosting capacity is a prudent approach. We also found that stakeholders supported Ergon Energy undertaking more investments to integrate CER in its network. We found that Ergon Energy's business case and supporting analysis is somewhat flawed as it overstates the level of "business as usual" investment needed to maintain the export service, absent its proposed investments. However, in support of its proposed investments, we found that Ergon Energy understated the likely emissions reductions benefits by applying values lower than the now published interim values of emissions reduction. We also consider that greater network visibility is necessary so that Ergon Energy can better identify export constraints and existing service levels and prioritise its investments. This is further discussed in Appendix B.6.
Other non-network	Our draft decision includes Ergon Energy's other non-network forecast of $31.7 million as part of our total capex forecast. Ergon Energy submitted that the drivers for the uplift in other non-network are additional field employees and fleet. It demonstrated to us that its forecast is based on historical expenditure with adjustments for its forecast changes in field employees and fleet numbers. We are satisfied that Ergon Energy's forecasts method is reasonable and its forecast for other non-network is reflective of the efficient costs of a prudent operator.
Asset disposals	Our draft decision includes Ergon Energy's updated asset disposals forecast of $42.1 million as part of our total capex forecast. Ergon Energy initially proposed $22.3 million for asset disposals for fleet and property. We identified discrepancies with the information provided and Ergon Energy updated its forecast to $42.1 million.[35] This involved correcting an error in fleet disposals from $4.1 million to $23.9 million.

34 The SOCI Act designates electricity assets as critical infrastructure and mandates compliance obligations within the framework under the Act.

35 Ergon Energy, *Response to information request 027*, May 2024.

Driver	Findings and reasons
Repex	Our draft decision does not include Ergon Energy's repex forecast of $2,718.8 million as part of our total capex forecast. Instead, we have included a substitute estimate of $1,844.3 million, which is $874.5 million (32.2%) lower than Ergon Energy's forecast. As Ergon Energy proposed a material increase across almost all repex sub-categories at a top-down level, we undertook a bottom-up review of most of its repex programs. Overall, we identified a number of concerns that did not provide us with confidence of the prudency and efficiency of its forecast. Firstly, while Ergon implemented risk cost modelling, the basis of most of its forecast was average historical costs, which we found to be inefficient in our ex-post review. Secondly, we found evidence of inefficient opportunistic replacement where assets were being replaced much earlier than their economic life. Thirdly, we found a lack of robust cost benefit analysis to support its forecast including incorrect application of the counterfactual, overstatement of benefits, and significant errors with modelling. This is further discussed in Appendix B.1.
Augex	Our draft decision does not include Ergon Energy's augex forecast of $513.2 million as part of our total capex forecast. Instead, we have included a substitute estimate of $429.2 million, which is $84.0 million (16.4%) lower than Ergon Energy's forecast. For its Distribution Feeder Augmentation Maintain Reliability project, we found no increasing trend in reliability for unplanned outages and therefore little justification for this project. Further, although Ergon Energy identified unplanned energy unsupplied as the driver, this program also appears to be addressing the increase in unsupplied energy from planned outages. We note that the increase in planned outages is in part due to the increased level of construction activity across Ergon Energy's network and should not be addressed as part of this reliability investment. For its grid communications, protection and control sub-category expenditure, we found the forecast to be overstated. Our main concerns relate to a lack of overarching strategy, minimal options analysis, and deliverability concerns. This is further discussed in Appendix B.2.
Information and communications technology (ICT)	Our draft decision does not include Ergon Energy's ICT capex forecast of $258.8 million as part of our total capex forecast. Instead, we have included a substitute estimate of $208.7 million, which is $50.1 million (19.4%) lower than Ergon Energy's forecast. We assessed Ergon Energy's proposed 6 non-cyber major investments and consider the business cases do not provide sufficient information to support its preferred options. We consider its 'maintain' base case option to be a prudent and efficient investment and therefore included a substitute estimate based on this option. This is further discussed in Appendix B.4.
Resilience	Our draft decision does not include Ergon Energy's forecast of $53.1 million for resilience as part of our total forecast capex. Instead, we have included a substitute estimate of $26.8 million, which is $26.2 million (49.4%) lower than Ergon Energy's forecast. In coming to this position, we note that Ergon Energy did not provide much of the evidence expected in resilience-related proposals that the AER set out in its guidance note on network resilience. We encourage Ergon Energy to provide this further information in its revised proposal. Overall, we found that Ergon Energy's proposed bushfire and flood programs are reasonable. While Ergon Energy has not been clear about how its mobile substation expenditure is resilience-related, we

Driver	Findings and reasons
	consider this expenditure is reasonable, especially to comply with the safety net targets.[36] However, we have concerns about the prudency and efficiency of its mobile generation program and SAPS program, and therefore have not accepted these components of its resilience expenditure. This is further discussed in Appendix B.5.
Fleet	Our draft decision does not include Ergon Energy's fleet forecast of $243.0 as part of our total capex forecast. Instead, we have included a substitute estimate of $210.1 million, which is $32.9 million (13.6%) lower than Ergon Energy's forecast. Ergon Energy submits that the forecast is primarily driven by higher unit rates, addressing shortfalls in current period replacements, changes to replacement strategies, and an FTE uplift. We found that Ergon Energy did not provide sufficient evidence to support a 46% step up in its forecast relative to the current period. In particular, we found that Ergon Energy had not provided sufficient justification for its proposed changes to the replacement strategies of elevated work platforms (EWP) and crane borers. In addition, we have made adjustments to the FTE uplift based on capex reductions to other categories within its forecast. This is further discussed in Appendix B.7.
Property	Our draft decision does not include Ergon Energy's property forecast of $174.7 million as part of our total capex forecast. Instead, we have included a substitute estimate of $170.7 million, which is $4.0 million (2.3%) lower than Ergon Energy's forecast. Aside from one major investment, we consider Ergon Energy's forecast reasonably reflects the efficient costs of a prudent operator. As part of its business case for the Townsville training facility redevelopment, Ergon Energy included benefits that we do not consider are benefits to consumers of standard control services. Adjusting for this, the preferred investment is the lower cost base case option, which we included in our substitute estimate. This is further discussed in Appendix B.8.
Capitalised overheads	Our draft decision does not include Ergon Energy's capitalised overheads forecast of $1,316.1 million as part of our total capex forecast. Instead, we have included a substitute estimate of $874.4 million, which is $441.7 million (33.6%) lower than Ergon Energy's forecast. We do not consider that the methodology that Ergon Energy has used to calculate its capitalised overheads is reasonable. Our alternative estimate applies the AER's standard methodology. This is further discussed in Appendix B.9.
Modelling adjustments	Our draft decision includes our standard modelling adjustments for updated inputs for inflation and labour real cost escalation. Updated inflation decreases our alternative estimate by $14.1 million while updating labour real costs escalation increases our alternative estimate by $10.8 million. The net impact of these adjustments decreases our alternative estimate by $3.4 million.

[36] For more information on Ergon Energy's safety net targets, refer to the Appendix B section B.5 on resilience.

A Ex-post review

From one control period to the next, the RAB is updated to include actual capex incurred. Clause S6.2.2A of the NER provides that in certain circumstances we may reduce the amount by which a DNSP's RAB is to be increased as part of the RAB roll forward. One of these circumstances is where a DNSP has spent more than its capex forecast ('the overspending requirement'). In this case, we may exclude capex above the forecast from the RAB if, after an ex-post review, we consider it does not reasonably reflect the capex criteria.

The relevant period over which this ex-post review is to occur comprises the first three years of the current regulatory control period and the last two years of the preceding regulatory control period. For Ergon Energy, the ex-post period is 2018–23. This differs from the period covered by clause 6.12.2(b) of the NER and for the Capital Expenditure Sharing Scheme (CESS) benefit/penalty calculation, which for Ergon Energy is the current regulatory control period, 2020–25.

A.1 AER draft decision

Our draft decision is that we are not satisfied that Ergon Energy's capex overspend in the ex-post period (2018–23 period) of $1,195.0 million ($2024–25) reasonably reflects the capex criteria (in particular, we are not satisfied that it reasonably reflects the prudent and efficient costs to meet the capex objectives). As such, we have not included Ergon Energy's capex overspend of $1,195.0 million into the opening RAB for the 2025–30 period. We have instead included an alternative overspend estimate of $598.8 million into the opening RAB, a reduction of 50.0% compared to Ergon Energy's proposal.

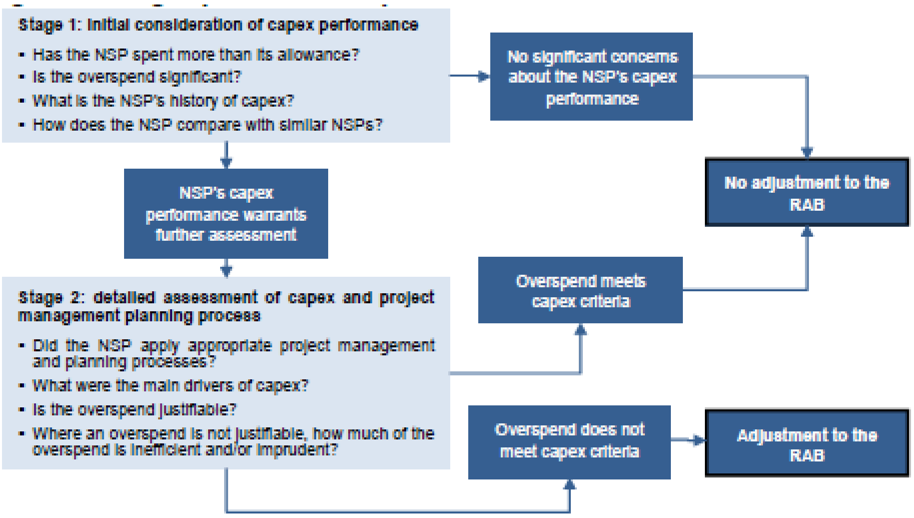
In the rest of this section, we discuss the framework applied to assess the overspend in the ex-post period and reasons for our draft decision.

A.2 Staged process for the ex-post review

We reviewed Ergon Energy's capex overspend in line with the staged review process in the AER's Capital Expenditure Incentive Guideline for Electricity Network Service Providers.[37] Figure A.1 sets out the staged process. The first stage considers whether the overspend is significant at the total forecast capex level. If we consider that the DNSP's capex overspend warrants further assessment, stage 2 involves a deeper bottom-up review of the capex overspend.

37 AER, *Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, April 2023, pp. 13-15.

Figure A.1 Staged process for the ex-post review



Source: AER, *Capex Expenditure Incentive Guideline for Electricity Network Service Providers*, April 2023.

Overall, we have assessed that, at the total forecast capex level, Ergon Energy's total capex overspend of $1,195.0 million is significant. As such, we consider that further assessment is warranted.

When the overspend is reviewed at the category level, we found that repex contributes the most to the overspend. The overspend in repex of $1,231.9 million represents 86.6% of the capex categories that have an overspend.[38] We have therefore undertaken a bottom-up review of the overspend in repex.

Our bottom-up review at stage 2 of the ex-post review involves the consideration of, amongst other things:

- what the main drivers of the overspend were and the reasons for the variation between actual costs and the forecast
- whether Ergon Energy applied appropriate project management and planning processes
- whether the overspend was justifiable, and if it is not, how much of the overspend is not efficient and prudent.

Submissions from the RRG,[39] CCP30[40] and Origin Energy[41] in response to our Issues Paper supported a bottom-up review of the overspend.

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38 As the net overspend of $1,195.0 million includes the underspend in augex and fleet which is higher than $1,231.9 million, this percentage calculation is only based on the capex categories that have had overspends and assessed as part of our ex-post review (i.e. excluding the augex and fleet underspend).

39 Energy Queensland Reset Reference Group, *Submission on Ergon Energy and Energex's electricity distribution regulatory proposals 2025–30 and the Australian Energy Regulator's Issues Paper*, May 2024, p. 3.

40 CCP30, *Advice to the AER regarding the Energex and Ergon Energy regulatory proposals 2025–30 – Response to the Proposal and Issues Paper*, May 2024, p. 11.

41 Origin Energy, *Submission to the Energex, Ergon Energy and SA Power Networks regulatory proposal*, May 2024, p. 1.

Other overspends are in categories that contribute materially less to total capex; these being in ICT which contributes about 8.7% to the overspend, property which contributes about 4% to the overspend, connections which contributes 3.4% to the overspend, and overheads which contributes 7.2% to the overspend. We undertook a high-level review of these areas of overspend.

A.3 Reasons for our Draft Decision

In this section, we discuss reasons for our draft decision on the overspend for:

- Repex
- Property
- Connections
- ICT
- Capitalised overheads.

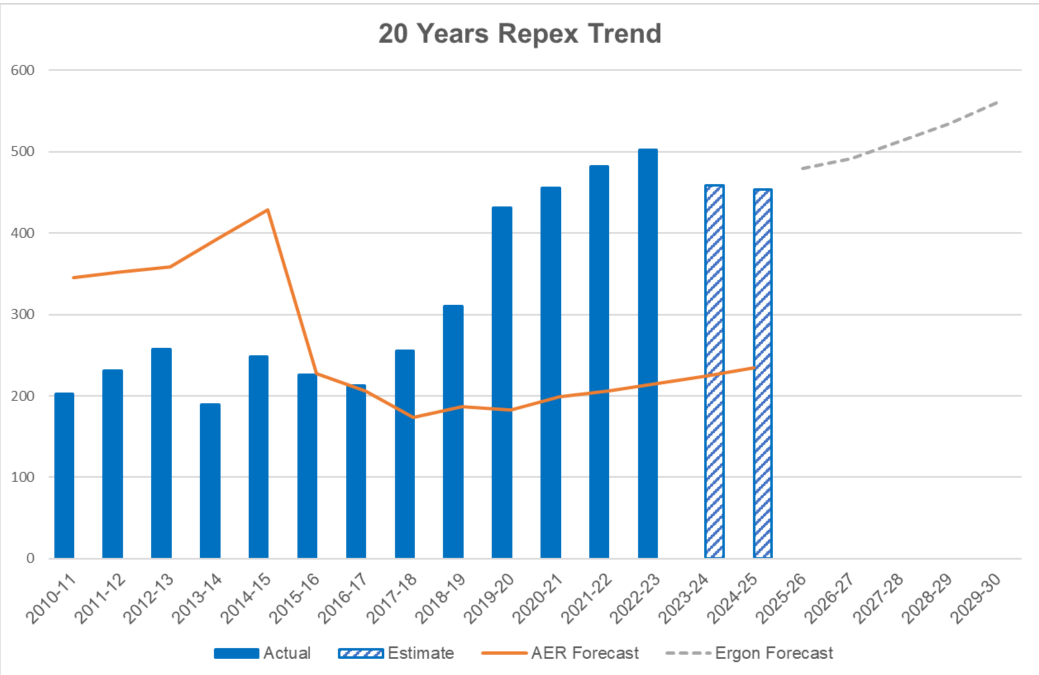
A.3.1 Repex

Our draft decision is to not include Ergon Energy's repex overspend of $1,231.9 million into the opening RAB for the 2025–30 period. We have included an alternative overspend repex estimate of $674.0 million, a reduction of 45.3% compared to Ergon Energy's incurred repex overspend.

A.3.1.1 Historical trend

Figure A.2 shows that the historical trend in repex for Ergon Energy. As can be seen, Ergon Energy's repex overspend occurs in every year of the ex-post period, and also increases each year. The level of repex in the ex-post period is also considerably higher compared to previous years.

Figure A.2 Ergon Energy historical repex trend ($ million, $2024–25)



Source: Ergon Energy's proposal and AER analysis

Table A.1 shows that that the overspend in repex in the ex-post period has occurred in almost all repex categories, other than in conductor assets. As can be seen, the largest areas of overspend are in pole, switchgear, pole top structure and transformer assets.

Table A.1 Ergon Energy actual repex by category ($ million, $2024–25)

Asset	Ergon Energy 2018–23 actuals	AER 2018–23 forecast	Overspend	% change
Poles asset	555.5	214.2	341.3	159.4%
Conductor asset	199.0	211.6	-12.6	-5.9%
Pole top structure asset	343.2	109.0	234.2	214.9%
Transformer asset	383.9	176.5	207.4	117.5%
Switchgear asset	362.6	94.6	268.0	283.3%
Service asset	124.8	62.3	62.5	100.3%
SCADA, control and protection assets	108.6	66.8	41.8	62.6%
Other assets	143.8	54.6	89.3	163.5%
Total repex	**2,221.5**	**989.6**	**1,231.9**	**124.5%**

Source: AER analysis.
Note: 'Other assets' includes 'Underground cable asset'

A.3.1.2 Bottom-up review

Consistent with stage 2 of the ex-post review process set out above, we have reviewed Ergon Energy's repex overspend having regard to the following considerations:

1) what the main drivers of the overspend were and the reasons for the variation between actual costs and the forecast.
2) whether Ergon Energy applied appropriate project management and planning processes; and
3) whether the overspend was justifiable, and if it is not, how much of the overspend is not efficient and prudent.

We discuss our assessment on each of these considerations below.

1) What are the main drivers of the overspend and the reasons for the variation between actual costs and the forecast?

The primary drivers of the repex overspend are:

- Ergon Energy's response to an unanticipated increase in unassisted pole failures
- Opportunistic (consequential) replacement of assets
- An increase in unit costs of Ergon Energy's clearance-to-ground/clearance-to-structure (CTG/CTS) programs.

Other factors that lead to the overspend are:

- higher expenditure in stand-alone transformer and switchgear programs

- higher expenditure in SCADA, network protection and control.

Table A.2 shows the contribution of each of these drivers to the total repex overspend. The CTG/CTS overspend contributes $154 million or 13% to total overspend, and this is not explicit in Table A.2 because the CTG/CTS program involves some of these assets.[42]

We discuss these drivers, in turn, below.

Table A.2 Contribution of drivers to the total repex overspend

Driver	Contribution to the overspend ($'m)	Contribution to the overspend (%)
Pole assets overspend (including opportunistic pole replacement)	341	28%
Opportunistic replacement (excluding pole opportunistic replacement)	544	44%
Other assets and stand-alone programs	131 (other assets) 216 (stand-alone program)	28%

Source: AER Analysis

Ergon Energy's response to an unanticipated increase in unassisted pole failures

Ergon Energy submits that it identified an increase in unassisted pole failures prior to its submission of its regulatory proposal for 2020–25, and that it exceeded the Electrical Safety Code of Practice – Works (ESCOP) three-year moving average pole failure rate of 1 per 10,000 poles.

The ESCOP includes specifications in relation to pole management. In particular, the ESCOP specifies the following:[43]

- A minimum three-year moving average reliability of 99.99 % per annum or an average pole failure rate of 1 per 10,000 poles
- Each pole should be inspected at intervals deemed appropriate by the entity. In the absence of documented knowledge of pole performance, poles should be inspected at least every five years.
- A suspect pole must be assessed within three months; an unserviceable pole must be replaced or reinstated within 6 months.

On the first specification in the ESCOP, we note that in 2019–20, Ergon Energy did exceed the ESCOP's three-year moving average pole failure rate of 1 per 10,000 poles, Figure A.3 shows the three-year moving average overtime and the ESCOP's limit. While we observe the increasing trend in the three-year moving average, we also note that the rate is trending downward by 2022–23.

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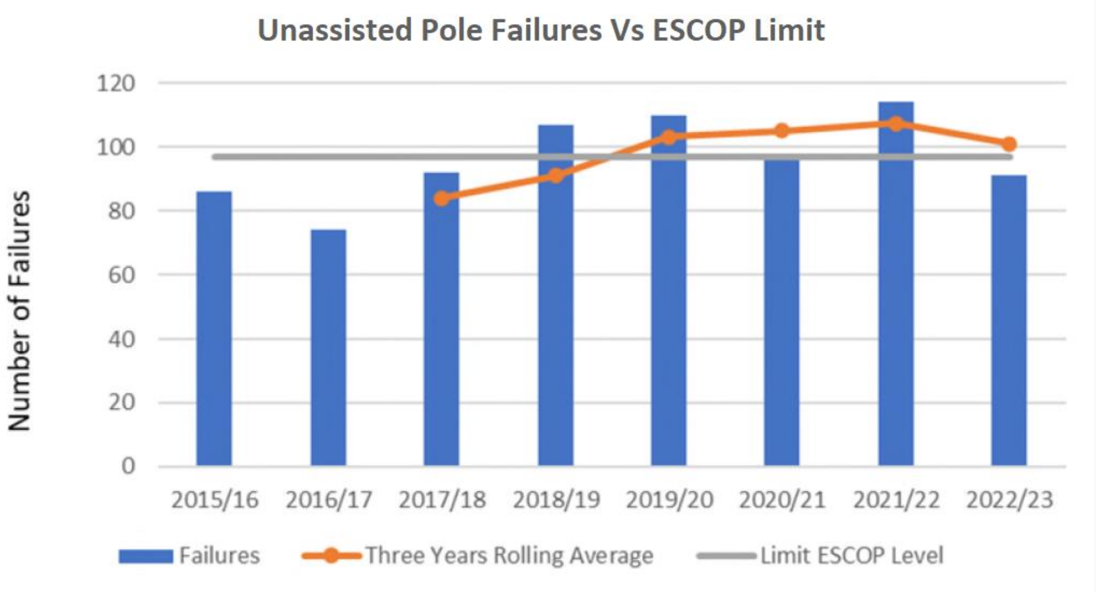
42 Based on information submitted by Ergon Energy, CTG/CTS programs are comprised of pole, conductor, pole top structure, switchgear, transformer, service and underground assets.

43 Electrical Safety Office, *Electrical Safety Code of Practice – Works,* January 2020, p. 22.

Figure A.3 Comparison on Ergon Energy's unassisted pole failures against the ESCOP limit



Source: Ergon Energy, *Att. 5.4.01 Pole Replacements Business Case*, January 2024, p. 24

Ergon Energy submits that its concerns with the increasing pole failures lead to, in 2017–18, an improvement in data collection of defective poles, and then in early 2019, a review of its pole strength calculations. This review led to the following changes:[44]

- Reduced pole inspection cycles of 6 and 8 years to 5 years to align with ESCOP specifications
- Improved field staff training in data capture and collection
- Improved pole inspection serviceability calculations.

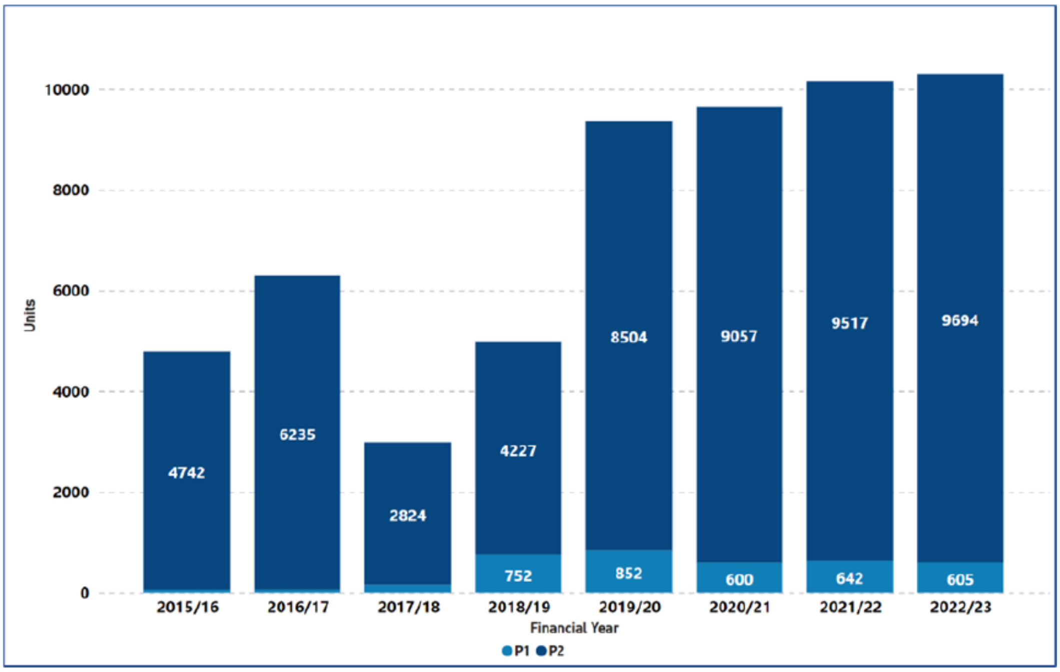
With respect to pole inspection, in April 2019, Ergon Energy updated certain aspects of its pole assessment process. This process is used to identify poles for replacement. Ergon Energy stated that it standardised its pole assessment process with Energex's and also to comply with Australian Standard AS 7000.[45]

Figure A.4 shows the historical trend in poles defects. As can be seen, there is an increase from 2017–18 and then to much higher levels of defects in the 2019–20 to 2022–23 period. These improvements to its pole management practices have led to a higher level of pole defects being identified.

[44] Ergon Energy, *Att. 5.03.02 Attachment A Pole Replacements Ex post Review of Ergon Energy 2018–2023 Capital Expenditure*, January 2024, p. 7.

[45] Ergon Energy, *Response to information request 025*, May 2024, p. 3.

Figure A.4 Historical pole defects in Ergon Energy



Source: Ergon Energy, *Att. 5.03.02 - Attachment A Pole Replacements Ex post Review of Ergon Energy 2018–2023 Capital Expenditure*, January 2024, p. 7.

Opportunistic (consequential) replacement of assets

We found that a significant number of assets were being replaced at the same time as poles were being replaced. Generally, it is accepted practice for DNSPs to replace low-cost assets like pole top structures and possibly services at the same time as pole replacement. Typically, a business would determine whether it is cost effective to do so.

Ergon Energy submits that: [46]

> The increase in pole replacements has also driven an increase in replacements of equipment such as crossarms, transformers, service lines and switches that are attached to the pole. Where feasible and cost effective, these assets were also replaced at the same time.

An increase in unit costs of Ergon Energy's CTG/CTS programs

Ergon Energy submits that the increase in clearance defects from its new identification technology is the reason for the overspend in CTG/CTS in the ex-post period.[47] Ergon Energy submits that, prior to 2015, clearance defects were identified manually by asset inspectors through visual estimation. In 2014–15, Ergon Energy employed ROAMES aerial LiDAR technology to identify clearance defects. This improved methodology was further enhanced in late 2021 when a temperature correction algorithm was applied to ground clearances. This resulted in a significant increase in the identification of breaches of Ergon Energy's legislative clearance obligations, which has resulted in increased expenditure on its CTG/CTS program.[48]

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46 Ergon Energy, *Overview – Ex post Review of Ergon Energy 2018–2023 Capital Expenditure: Justification Paper*, January 2024, p. 7.

47 Ergon Energy, *Overview – Ex post Review of Ergon Energy 2018–2023 Capital Expenditure: Justification Paper*, January 2024, p. 7.

48 Ergon Energy, *Overview – Ex post Review of Ergon Energy 2018–2023 Capital Expenditure: Justification Paper*, January 2024, p. 7.

Clauses 207 of the *Electrical Safety Regulation 2013* (Qld) sets out Ergon Energy's compulsory regulatory obligations in relation to CTG/CTS. These clearances are designed to minimise the risk that people or their property/equipment will come into contact with electrical lines. Schedules 4 of the *Electrical Safety Regulation 2013* (Qld) sets out the clearance of overhead electric lines from ground and structures.

Contrary to Ergon Energy's submission, we found that the increase in in CTG/CTS expenditure has not been due to increased volumes but an almost doubling of unit rates and opportunistic replacement.

2) Did Ergon Energy apply appropriate project management and planning processes?

We had regard to EMCa's advice on whether Ergon Energy had applied good governance and asset management practices at the time it made its investment decision to exceed the AER's 2020–25 Final Decision forecast.

Ergon Energy's decision to overspend on poles is set out in an Energy Queensland Board Paper in December 2020, 6 months after the release of the AER's 2020–25 Final Decision in June 2020.[49] The paper stated that the forecast is $484 million above Ergon Energy's revised regulatory proposal and $948 million above our final decision. However, there appears to be no updated business case or root cause analysis underpinning the additional capex requirement at the time.

EMCa advises that it would expect there would have been evidence-based justification for the investment including how that expenditure had been derived as a standard artefact of Energy Queensland's work program governance.[50]

EMCa concludes that Ergon Energy did not prepare and did not undertake detailed business case justification for its proposed investment as it suggested. EMCa submits that it requested copies of revised business cases relied upon for approval for the increased repex program and observes that:[51]

> In response, we were provided copies of the business cases and models submitted to the AER for its RP [2020–25 Regulatory Proposal] and RRP [2020–25 Revised Regulatory Proposal]. Given that the Board approved in December 2020 a significantly higher level of expenditure than was proposed in the RP or RRP, we fail to understand the relevance of the information provided to the AER when this is clearly not what the December 2020 approval was based upon.

While Ergon Energy did provide business cases for distribution transformers, conductors and switches, on review of these, EMCa found that the analysis supports the AER's Final Decision forecasts for these assets.

Based on the information before us, we consider that Ergon Energy did not apply appropriate good governance and asset management practices at the time of its investment to elevate its expenditure above the AER's 2020–25 Final Decision forecast.

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49 Ergon Energy, *Energy Queensland, 2012–15 Ergon Capex Investment Forecast 2020 to 2025, December 2020*.

50 EMCa*, Ergon Energy 2025/26 to 2029/30 Regulatory Proposal, Review of Aspects of Proposed Expenditure, September 2024*, p. 50.

51 EMCa, *Ergon Energy 2025/26 to 2029/30 Regulatory Proposal, Review of Aspects of Proposed Expenditure, September 2024,* p. 50.

3) Is the overspend justifiable, and if it is not, how much of the overspend is not efficient and prudent?

In considering whether Ergon Energy's overspend was justifiable, we had regard to all the information before us. We discuss our findings below.

We encourage Ergon Energy to engage with us prior to its submission of its revised proposal to discuss what further information is available to support its proposal. In section A.3.1.3, we set out the information and data gaps we have identified in Ergon Energy's proposal and would expect to be addressed in its revised proposal.

Poles overspend

In the ex-post period, Ergon Energy overspent by 159.4% (or $341.3 million) on poles repex. Given the increasing trend in pole defects from 2017–18, we consider there was a genuine need to address this increasing trend during the ex-post period. We also consider that there was a need for Ergon Energy to improve its pole management practices including pole inspection and pole data management. EMCa also makes a similar finding:[52]

> We consider that presented with an increase in the pole failure rate, and with work not being completed to address unserviceable poles in a timely manner, it was reasonable to commence a review of pole management process and to take corrective action.

We also note Ergon Energy's own admission that in the AER's 2015–20 review it submitted a forecast of poles repex that was incorrect and too low.[53]

Overall, we have not been presented with sufficient evidence to support the prudency and efficiency of Ergon Energy's total poles overspend. This is consistent with EMCa's finding where it states:[54]

> We consider that Ergon has established a reasonable basis for higher expenditure on these programs, however the extent of expenditure that Ergon has incurred on these programs has not been reasonably demonstrated.

To determine whether Ergon Energy's poles overspend is prudent and efficient, we had regard to a number of factors, including:

- EMCa's advice about the lack of information at the time of the investment decision to support prudency and efficiency of the overspend. Its advice was discussed above.
- Our assessment of Ergon Energy' s governance and asset management practices in the ex-post period.
- EMCa's review of Ergon Energy's Post Implementation Reviews (PIRs) that Ergon Energy submitted in support of the prudency and efficiency of poles repex during the ex-post period.

We discuss the latter two points below.

Ergon Energy' s governance and asset management practices

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52 EMCa, *Ergon Energy 2025/26 to 2029/30 Regulatory Proposal, Review of Aspects of Proposed Expenditure, September 2024*, p. 42

53 Ergon Energy, *Att. 5.3.02 Attachment A Pole Replacements Ex post Review of Ergon Energy 2018–23 Capital Expenditure, January 2024,* p. 11

54 EMCa, *Ergon Energy 2025/26 to 2029/30 Regulatory Proposal, Review of Aspects of Proposed Expenditure, September 2024*, p. xii.

We have a number of concerns with Ergon Energy's governance and asset management practices; these being:

- Ergon Energy's response to the emerging issue with its pole population by adopting Energex's pole management practices and standards.
- It does not appear that Ergon Energy took a root cause analysis at the time that issues emerged with its pole population. It is good industry practice to identify the reason for failures/defects to target the investment.
- Ergon Energy did not undertake a RIT-D or equivalent analysis to test the different options to address the increasing trend in unassisted pole failures and increase in replacement in other assets. Absent this type of analysis, we do not have confidence that Ergon Energy's elevated pole expenditure represents the investment that has the greatest net benefit to consumers.
- Ergon Energy did not have processes/arrangements in place at the time of decision to increase its expenditure above the AER forecast to restrain its expenditure or periodically review its expenditure. It is good industry practice to review investments and recalibrate to incorporate new learnings.

We discuss the first two points below.

<u>Ergon Energy's adoption of Energex's pole management practices and standards</u>

In response to the emerging issues with its pole population, Ergon Energy adopted Energex's pole management practices and standards. EMCa observes that while the change to Ergon Energy's asset management practices and standards from its 2019 review are generally consistent with reasonable management responses to emerging issues, it also found that:[55]

> …the pole management methods employed by Ergon has generally led to a higher pole replacement rate, and therefore high level of expenditure than is prudent without adequate consideration of differences between the two networks and the customers they serve.

Like EMCa, we consider that Ergon Energy's response by adopting Energex's pole management practices and standards has resulted in higher pole replacement than is efficient. Energex, as an urban network, has an inherently different level of risk than Ergon Energy's network, therefore applying Energex's practices and standards has led to unnecessarily high costs to maintain asset performance.

EMCa also advises that Ergon Energy did not provide evidence that it tested and considered the outcomes from applying Energex's pole management practices and standards. EMCa notes that:[56]

> We have not identified any material issues from this independent review that would result in a departure for pole serviceability compared with our experience of methods employed in other DNSPs in the NEM. However, we note that the adoption of standards intended for a predominantly urban customer group, may need to be moderated for application to Ergon's network such that the service and reliability outcome are matched with the value placed on those outcomes by the customers in that service area. We did not see evidence that Ergon or EQ had considered the

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55 EMCa, *Ergon Energy 2025/26 to 2029/30 Regulatory Proposal, Review of Aspects of Proposed Expenditure,* September 2024, p. 19

56 EMCa, *Ergon Energy 2025/26 to 2029/30 Regulatory Proposal, Review of Aspects of Proposed Expenditure,* September 2024, p. 57.

> differences or indeed the potential for adopting a set of standards that may result in higher service and reliability outcomes than are valued by customers.

Ergon Energy did not undertake a root cause analysis to determine the reason for the increasing trend in pole defects

Consistent with good industry practice, we would expect a prudent and efficient operator to undertake a review like a root cause analysis to determine the underlying problem with its poles and therefore target the replacement.

EMCa observes that Ergon Energy did not undertake a sufficient review of the drivers of the increase in pole defects:[57]

> During our onsite discussion, we asked Ergon for details of its defect analysis and specifically whether it had identified any sub-population of poles that were drivers of increasing defects. Whilst Ergon provided some information during that discussion identifying some species of poles, we were not convinced that Ergon's forecasting methods for defects have adequately considered the influence of sub-populations of poles which could inform the selection of prudent and efficient treatment strategies.

From a customer's perspective, the CCP30 notes:[58]

> Has there been a meaningful cause analysis as to how this situation arose? A critical question for customers is 'is this an additional cost to get back on track, or is this the new normal?' Root cause analysis is critical to guide the longer-term investment imperatives.

While we acknowledge that an elevated level of pole replacement would resolve pole performance issues in the ex-post period, a generic approach to asset management in the absent of a root cause analysis will lead to overinvestments compared to a targeted approach. The CCP30 questions whether bringing forward pole replacement was the prudent and efficient response:[59]

> Must it all be done now? We recognise the imperative to address safety risks quickly; but again, in a capital constrained situation, risk management, prioritisation and a more measured approach may be necessary

Little weight can be placed on Ergon Energy's PIRs

Ergon Energy's PIR provides the results of Ergon Energy's NPV analysis comparing the actual delivered repex with options including the AER final decision repex for the 2020–25 period.

We found Ergon Energy's PIR did not genuinely seek to critically evaluate the effectiveness of its pole replacement program and other capex incurred. This PIR also appeared to be heavily biased towards Ergon Energy's preferred option. In particular, EMCa found:[60]

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57 EMCa, *Ergon Energy 2025/26 to 2029/30 Regulatory Proposal, Review of Aspects of Proposed Expenditure,* September 2024, p. 58.

58 CCP30, *Advice to the AER regarding the Energex and Ergon Energy regulatory proposals 2025–30*, May 2024, p. 12.

59 CCP30, *Advice to the AER regarding the Energex and Ergon Energy regulatory proposals 2025–30*, May 2024, p. 12.

60 EMCa, *Ergon Energy 2025/26 to 2029/30 Regulatory Proposal, Review of Aspects of Proposed Expenditure,* September 2024, p. 29.

- The counterfactual (BAU) case is incorrect as it does not allow an unbiased assessment of Ergon Energy's preferred and other options. Typically, the BAU assumes that the asset(s) are not retired and are operated and maintained on a BAU basis. Ergon Energy has defined the counterfactual as assuming that assets are retired and replaced at the same time. As the BAU already includes the asset replacement, a proper comparison between BAU and Ergon Energy's preferred option (which includes replacement) cannot be made.
- The assessment period of benefits does not align with the costs, where Ergon Energy has included a 20-year assessment period for the benefits and only 5 years for the risk costs avoided. Only considering 5 years for costs does not accurately represent the actual investment that will be incurred by Ergon Energy over the assessment period. At a minimum, failed assets would need to be replaced for every asset class, and therefore the investment would not be zero, and this investment would impact the calculation of benefits. By considering benefits over 20 years, the risks (and therefore assumed benefits) exponentially increase over that period which creates a significant difference between the options at 20 years. This in effect drives the major difference in the benefits between options and bestows high NPV values on Ergon Energy's high-replacement option.
- The assumed benefits of Ergon Energy's delivered program are not credible. Ergon Energy's analysis generates a net benefit of $1.1 billion from Ergon Energy's actual delivered repex program compared to the lower AER final decision repex. EMCa does not find this value of additional claimed net benefits credible, noting that it largely results from the inappropriate aspects of its modelling, as noted above.

Opportunistic replacement

Opportunistic replacement can be considered good industry practice where it leads to cost efficiencies. This may involve, for example, replacing an aging cross-arm or conductor during a pole replacement. However, our review of Ergon Energy's supporting material is that in many instances, opportunistic replacement has not been cost effective. In particular, we found that Ergon Energy's own analysis demonstrates that in many cases, this activity is associated with a negative cost benefit.[61]

Ergon Energy's opportunistic replacement makes up $544.0 million or up to 44.2% of the total repex overspend. We note that the majority of this replacement ($282.2 million or 51.9% of the $544.0 million) has been to assets like transformers and switchgear. Ergon Energy's reasons for replacing these assets are not based on safety, but rather that it is cost effective to do so: [62]

> The increase in pole replacements has also driven an increase in replacements of equipment such as crossarms, transformers, service lines and switches that are attached to the pole. Where feasible and cost effective, these assets were also replaced at the same time.

We analysed the RIN data, Ergon Energy's PIR and other information Ergon Energy submitted and found that a large number of assets were replaced at less than circa 40 years

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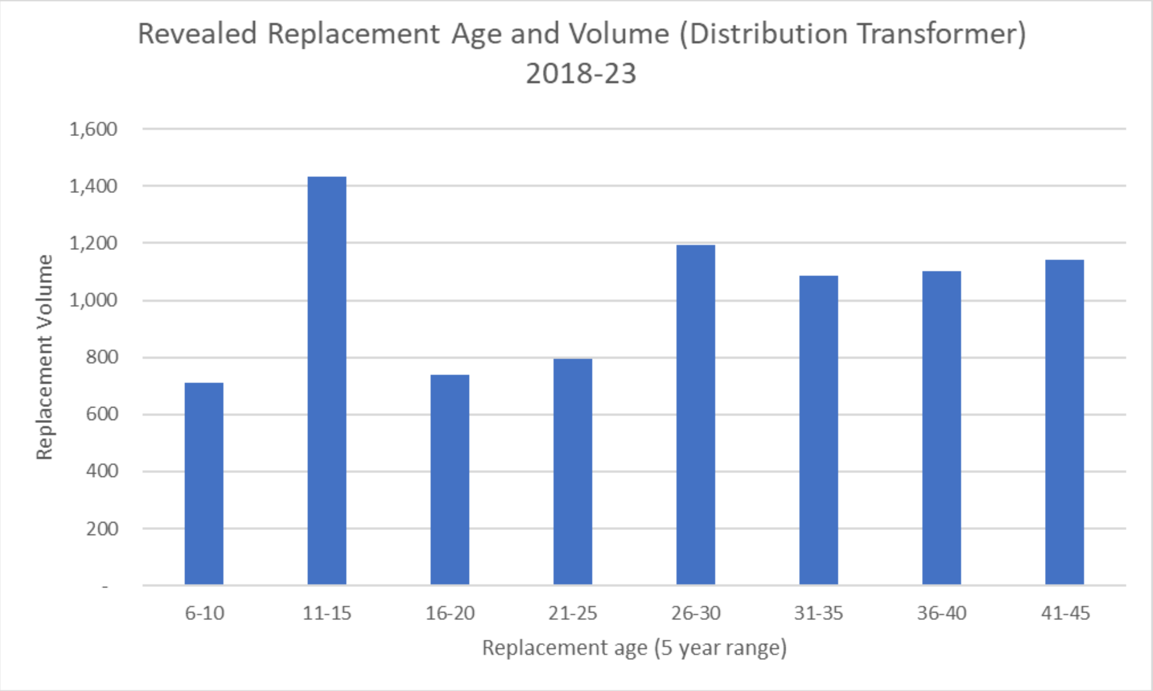
[61] Ergon Energy, *Att. 5.3.12 Poles Post Implementation Review,* January 2024*,* Table 17, p. 31.

[62] Ergon Energy, *Overview - Ex post Review of Ergon Energy 2018–2023 Capital Expenditure: Justification Paper*, January 2024, p. 7.

old when the design life and economic life of these assets should be at a minimum of 45-50 years.

By subtracting the 2022–23 and 2017–18 age profiles data submitted by Ergon Energy in its annual RIN, we get an indication on the volume of assets replaced and the age of replacement at the asset category level in the past 5 years (2018–23) for certain discrete assets. Figure A.5 shows the revealed replacement age of Ergon Energy's distribution transformers. As can be seen, Ergon Energy is replacing an unusually high volume of young assets, with more than 50% of its transformers being replaced at a replacement life of less than 35 years. The typical economic life of a transformer is 45 to 55 years. Notwithstanding the age profile data is imperfect and includes non-condition related driven replacements (i.e. third party and climate-related damages), we would not expect to see thousands of transformer replacements driven by exogenous factors in the past 5 years.

Figure A.5 Revealed Age of Replacement of Distribution Transformers



Source: AER analysis

We also note that Ergon Energy's practice of early replacement is inconsistent with Ergon Energy's own business rules. Ergon Energy's business rules state that there should not be bundling of non-defected distribution transformers and switchgears younger than 45 years.[63]

CTG/CTS overspend

We acknowledge Ergon Energy's regulatory obligations in relation to CTG/CTS in the *Electrical Safety Regulation 2013* (Qld). In particular, we appreciate that Ergon Energy has legislative obligations to address breaches of its clearance limits. We also met with the ESO

63 Ergon Energy, *Response to information request 041 – Question 3 - Technical Operational Update – Requirements for Replacing Pole-Mounted Plant – December 2021*, June 2024.

who indicated that a number of improvement notices had been served to Ergon Energy in recent times about its CTG/CTS program.

While we accept that Ergon Energy has legislative obligations to address breaches of its clearance limits, we found that the primary driver of the overspend has been an almost doubling of unit rates. We consider that Ergon Energy did not act in a prudent and efficient manner in choosing the considerably more expensive option of replacement compared to the lower cost industry accepted practice of re-tensioning (or a combination of re-tensioning and staking).

In response to an information request, we found that about half its CTG defects have a clearance gap of less than 20cm (low priority defects).[64] Typically, businesses employ re-tensioning of the conductor (or a combination of re-tensioning with pole staking) in many of these circumstances, with re-tensioning a common solution for clearance gaps of less than 20cm. We found that Ergon Energy was replacing these low priority defects instead of the lower cost option of re-tensioning.

We also note that our concerns about inefficiently high CTG/CTS unit costs contributed to our lower alternative capex forecast in our 2020–25 Final Decision, with a number of stakeholders raising concerns about the 85% step up in forecast unit rates and the lack of reasoning provided by Ergon Energy to support this.[65]

Other concerns

We also have concerns with other factors that have led to the overspend in the ex-post period; these being:

- higher expenditure than our 2020–25 Final Decision in stand-alone (targeted) transformer and switchgear programs
- higher expenditure in SCADA, network protection and control than our 2020–25 Final Decision.

Based on the information before us, we are not satisfied that the overspend in these areas has been prudent and efficient. We encourage Ergon Energy to provide further information to support these areas of overspend in its revised proposal.

In relation to higher expenditure in stand-alone transformers and switchgears, Ergon Energy did not provide evidence to indicate that there were any emerging risks with transformer and switchgear assets prior to or post its decision that would support an overspend of $193.2 million in these asset types. EMCa also came to the same conclusion.

EMCa also raised concerns about Ergon Energy's asset management strategy of 'replacing on defect' which may result in "transformers being prematurely replaced when a repair could have been undertaken to address the defect":[66]

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64 Ergon Energy, *Response to information request 050 – Question 5,* June 2024.

65 AER Final Decision, *Ergon Energy Distribution Determination 2020–21 – 2024–25, Attachment 5 Capital Expenditure*, June 2020, pp. 5.24-5.25.

66 EMCa, *Ergon Energy 2025/26 to 2029/30 Regulatory Proposal, Review of Aspects of Proposed Expenditure,* September 2024, p.69.

> Ergon describes the asset management strategy for distribution transformers as run-to-defect or run-to-failure. Ergon states that the defects reported result in transformer replacement with the primary reasons for replacement being corrosion (56%) and oil leakage (25%). We consider this is not a run to fail strategy, whereby replacements are made following failure of the transformer, but rather replace on defect. Subject to the classification method, this may result in transformers being prematurely replaced when a repair could have been undertaken to address the defect.

Further, we also found that the overspend is inconsistent with Energy Queensland's proposal in the December 2020 Energy Queensland Board paper that proposes a number of strategies to maintain expenditure to the level set in our 2020–25 Final Decision. One of these strategies was to downgrade Ergon Energy's defect categorisation so that the asset does not have to be replaced.

In relation to higher expenditure in SCADA, network protection and control, Ergon Energy indicates that this higher expenditure is to manage failure risks.

However, EMCa did not observe increasing in-service failures in the supporting documentation, or other indicators that would support the 38% overspend. EMCa notes:[67]

> We do not see evidence of increasing in-service failures in the supporting documentation provided. The figure provided in the ex post justification appears to be based on RIN information and, with the exception of the communication network assets, does not provide sufficient information to indicate an increasing trend in asset failures for the eight years provided. Nor do we see evidence of replacement strategies based on technical obsolescence risk or other indicators, which may indicate an increase in required replacement levels.

EMCa also found evidence of Ergon Energy bringing forward investment earlier than originally forecast for some sub-categories. EMCa notes that Ergon Energy has not provided reasons for this earlier investment.[68]

A.3.1.3 Information and data gaps in Ergon Energy's proposal

In addition to the information and data gaps that EMCa identified, we found further gaps that we encourage Ergon Energy to address in its revised proposal.

In terms of analysis:

- Evidence of root cause analysis, or working with us to unpack the pole defect data provided to us to identify the underlying concerns driving the investments (that is, poles, ex-ante pole top replacements, reliability driven programs, etc)
- Evidence of defect concerns with the pole population in a specific location such as the Western region which was informally raised with us late in the assessment process (late August)
- Any other information Ergon Energy may have relied on at the time it made the decision to overspend (other than the information already provided in the December 2020 Energy Queensland Board paper)

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[67] EMCa, *Ergon Energy 2025/26 to 2029/30 Regulatory Proposal, Review of Aspects of Proposed Expenditure,* September 2024, p. 76.

[68] EMCa, *Ergon Energy 2025/26 to 2029/30 Regulatory Proposal, Review of Aspects of Proposed Expenditure,* September 2024, p. 76.

- Evidence of the actions taken annually for each of the risk mitigating strategies listed in the December 2020 Energy Queensland Board approval
- Evidence of any benchmarking against other DNSPs (other than Energex) that Ergon Energy has undertaken
- Evidence of top-down checks against the derived bottom-up results (i.e. comparing bottom-up result against revealed performance)
- Evidence of the actions and quantitative analysis Ergon Energy may have undertaken to verify that its unit cost (clearances in particular) is efficient.

In terms of governance:

- Evidence of good portfolio management including an appropriate annual review of a rolling 5 to 7 years capex forecast based on the latest asset management input and the actions taken afterwards
- Evidence of portfolio prioritisation including a monetised list of projects and programs ranking from the highest to the least risk
- Evidence of top-down challenges from senior management including any actions taken to minimise the amount of overspend.

In terms of data accuracy and reconciliation:

- A complete project/program list with the same level of detail as Ergon Energy presented in the 2025–30 SCS capex model for the 2018–25 period. We would expect a continuity of individual projects/programs in the same format/structure between the 2018–25 and 2025–30 datasets on an annual basis that aligns with the historical and reset RINs.
- A bottom-up reconciliation of the historical replacement volume and replacement reasons against the Ergon Energy's submitted RIN information at the individual asset level (including each asset functional location, age and other key characteristics). We would expect an explanation if the data does not reconcile.
- There appears to be misalignment between the comments and the categorisation of failure in the detail failure data provided that requires further clarification.
- A reconciliation and a detailed explanation on the identified negative balancing items and discrepancies between data sources. We would expect Ergon Energy to nominate one version to be relied on and the reason this version should be relied on.
- Ergon Energy noted incorrect data was submitted in its 2020–25 proposal. We would expect a detailed explanation of the data error and the impact it had on its 2020–25 proposal including a reconciliation worksheet on the source data before and after the correction.

A.3.1.4 Alternative overspend estimate

We describe how we derived our alternative overspend estimate below, with a summary of the build-up in Table A.5 later in this section.

Poles overspend

At this stage, our alternative overspend estimate is based on the information before us. As noted earlier, we placed the most weight on the Ergon Energy's supporting information and data. However, we found data discrepancies, errors, reconciliation issues and information gaps with much of this information and data. This meant that we did not have sufficient confidence in the robustness of that information and data to undertake a bottom-up estimate. We hope to work with Ergon Energy prior to its submission of its revised proposal to discuss how we can work through some of the existing information and data that has been provided and/or whether there is any new information and data that would assist us in our assessment.

Due to our concerns with the information and data provided to us, we have had to explore other avenues to derive an alternative estimate. Our alternative overspend estimate for Ergon Energy's poles overspend and opportunistic replacement is based on benchmarking Ergon Energy's pole replacement rate against Essential Energy. We undertook comparative analysis between Ergon Energy and other DNSPs and found Essential Energy as the best available business to compare with Ergon Energy. This because Essential Energy faces similar challenges with the age and conditions of its poles as Ergon Energy. We found that Ergon Energy and Essential Energy have similar pole composition and operating environment factors (similar rainfall and humidity levels) that are likely to impact age and condition of their pole populations. Box 1 summarises the reasons for Essential being a comparable business to Ergon Energy for pole replacement rates.

Box 1 Summary of reasons for Essential Energy being a comparator to Ergon Energy's pole replacement rates

When considering whether Essential Energy provides a suitable benchmark for Ergon Energy, we are seeking to determine whether the businesses face similar challenges with the age and condition of their poles to align with good industry practice. We consider that pole composition (type of pole) and the pole population operating environment are key factors that affect age and condition of pole populations.

Ergon Energy and Essential Energy have similar pole composition

Essential Energy has a very similar proportion of timber, steel, and concrete poles to Ergon Energy. Also, while Essential Energy has a larger number of poles than Ergon Energy (approximately 29% more poles), this is mostly reflective of customer numbers (approximately 28% more customers) and the nature of the terrain supplied. Due to the higher density of population associated with the Great Dividing Range, Essential Energy would use more poles per customer than the equivalent areas of Ergon Energy. Similarly, Essential Energy has about 26% more overhead line which accords with the higher customer numbers, and the nature of the supply area terrain.

Ergon Energy's and Essential Energy's pole population have similar operating environments

Overall, our findings are that Ergon Energy's and Essential Energy's pole population degrade for similar reasons; that is, they are likely to experience similar fungal attack due to similar moisture levels in the environment (rainfall and humidity). While exposure to termites is greater in the Ergon Energy network, we do not have sufficient data at this stage to test the relative significance of termite attack on pole replacement rates. However, we note that the effect of termite exposure on the replacement rate of timber poles is likely to be impacted by inspection practices and in pole treatments. This would result in higher calculated opex per wooden pole that we take into account in our opex benchmarking, via an operating environment factor adjustment.

Source: AER analysis

In applying this approach, we have erred on the conservative side as we did not benchmark Ergon Energy against other potential comparators such as AusNet and Powercor which have a regional component to their service area. We note that Ergon Energy would have performed worse if we included these businesses because of their longer replacement lives.

We also did not take account of Ergon Energy's younger asset lives in our benchmarking (see Table A.3) and did not pursue concerns raised by EMCa about Ergon Energy's inefficiently high unit costs in some areas[69] and the overspend in the stand-alone programs for pole top structures and services.[70]

Table A.3 Comparing DNSP Customer Density and Weighted Average Age of Timber Poles

Network	Customer Line Density (no/km)	Timber Pole Population 2023 CA RIN	Weighted Average Age
Ergon Energy	5.5	871,347	34
Essential Energy	5.2	1,125,009	40
Powercor	13.0	317, 059	46
AusNet	20.3	179,081	44
Energex	34.2	405,578	28
Endeavour	37.6	292,929	31
Ausgrid	44.9	435,053	40

Source: AER analysis based on DNSPs annual CA RINs

Benchmarking against Essential Energy's replacement rate

Table A.4 shows the timber pole replacement rate for a number of DNSPs across different periods (using 2022–23 population as the base).

We have substituted Ergon Energy's replacement rate in 2018–23 of 7.45% with 4.9%. We derived 4.9% by using Essential Energy's rate of 3.95% and adding a 'catch up' of 0.95% where Ergon Energy's replacement rate in 2013–18 is lower than Essential Energy's (where 0.95% = 3.5% - 2.55%). We have considered the longer time series in coming to our alternative estimate given Ergon Energy had a lower replacement rate in 2013–18 although we note that this is not materially out of step with the replacement practices of other DNSPs at that time.

Applying the replacement rate of 4.9% to the 2013–18 period results in a 34.2% reduction of the total pole asset replacement (or a 55.6% reduction in its $341.3 million pole asset overspend).

69 EMCa, *Ergon Energy 2025/26 to 2029/20 Regulatory Proposal, Review of Aspects of Proposed Expenditure*, September 2024, p. 78-80.

70 EMCa, *Ergon Energy 2025/26 to 2029/20 Regulatory Proposal, Review of Aspects of Proposed Expenditure*, September 2024, p. 66.

Table A.4 Average 5-Year Replacement Rate of Timber Poles

	Average 5 Years Replacement Rate of Timber Poles		
Network	**2013–18**	**2018–23**	**2024–29 (NSW) 2025–30 (QLD)**
Ergon Energy	2.55%	7.45%	8.40%
Essential	3.50%	3.95%	4.92%
Powercor	2.19%	4.93%	n/a
AusNet	4.48%	4.21%	n/a
Energex	7.43%	3.62%	2.57%
Endeavour	2.40%	3.35%	3.72%
Ausgrid	2.99%	2.18%	2.28%

Source: AER analysis

Opportunistic replacement

For opportunistic replacement that relates more specifically to poles repex, these being: pole top structures and service assets, we have applied the same reduction as poles. That is, a 34.2% reduction to the associated capex in the affected programs.

For transformers and switchgears, our reduction to Ergon Energy's overspend is to both its opportunistic replacement and its stand-alone programs for these assets given our material concerns in both areas, as discussed above.

CTG/CTS

The reduction due to inefficient overspend in Ergon Energy's CTG/CTS program is not obvious in Table A.5 below, as this program involves a number of assets and we took an overall top-down approach in making a reduction across these affected asset classes.

Using our top-down approach at the asset level, our alternative overspend estimate for CTG/CTS is $128.3 million which is $95.6 million lower (or a 42.7% reduction) relative to Ergon Energy's actual spend of $223.6 million.

To verify our top-down estimate, we used a separate method to come to another alternative estimate. As we consider that clearance gaps less than 20cm can be addressed via re-tensioning, we derived the cost to re-tension where the clearance gaps were less than 15cm. This is about 46% of all clearance gap defects. We then applied the re-tension cost of $1,100 rather than Ergon Energy's cost of $13,000 to that 46%, applying Ergon Energy's $13,000 cost to the remaining 54%. This resulted in the reduction to its clearance program by 41.8%. This is in line with our top-down asset level adjustment of 42.7%.

Other concerns

As noted earlier, EMCa identified concerns with Ergon Energy's overspend on its SCADA, network control and protection systems. This is a sub-category within 'other assets'. We have included $48.0 million overspend that EMCa found to be reasonable. Of the remaining $83.0 million in that category, we have applied a proportional reduction as Ergon Energy submits that capex associated with its 'other assets' category moves in line with its overall capex.

Useful life/residual value

We have included a useful life/residual value of $253.5 million to reflect the remaining life in assets replaced early. We consider that in an ex-post assessment, once expenditure is spent, there should be acknowledgement that some of expenditure might still be prudent and efficient and can be rolled into the RAB despite the timing of the investment being sub-optimal. This is particularly relevant for replacement activities where every existing asset would need to be replaced eventually. For example, if a business replaces a transformer in 2020–21 for $1 million and we found that the optimum timing for replacement to be 2030–31 (so it has replaced 10 years earlier than efficient), rolling zero into the RAB would mean we are also rejecting the other 40 years of potential useful life after the expenditure has been spent (assuming a transformer has an economic life of 50 years). Our approach attempts to recognise the potential useful life of an asset after the expenditure has been spent. Further detail about the residual value approach including the need to treat ‘double-counting’ in the ex-ante period is in Box 2.

Box 2 Useful life/residual value

When undertaking an ex-ante assessment, if a business proposed repex that we consider is not prudent or efficient within the 5-year forecast period, we would include zero capex for this in our alternative estimate. For example, if a business proposes to replace a transformer in 2029–30 at $1 million and we found that the optimum timing for replacement to be 2030–31, we typically include zero in our alternative estimate for the 2025–30 period (that is, 100% of the expenditure is not prudent or efficient).However, in an ex-post assessment, once expenditure is spent, there should be acknowledgement that some of the expenditure might still be prudent and efficient and can be rolled into the RAB despite the timing of the investment being sub-optimal. This is particularly relevant for replacement activities where every existing asset would need to be replaced eventually. The residual value approach recognises the potential useful life (or the residual value) of an asset after the expenditure has been spent.

Removing the “double-count” in the ex-ante period

In our ex-post review, we are assessing actual expenditure that has yet to be rolled into the RAB as there are no provisions under the NER for a RAB write down. It is appropriate to remove the ‘double counting’ of depreciation of the new assets relative to the existing assets that continue to remain in the RAB until it is fully depreciated. For example, if a business replaces an existing transformer 10 years earlier than its economic life, it has in effect double counted 10 years of depreciation of the new asset even though the existing asset is no longer in service, because the remaining value still resides in the RAB. Our approach removes the ‘double counting’ of depreciation in any given year between the new and existing assets.

Source: AER analysis

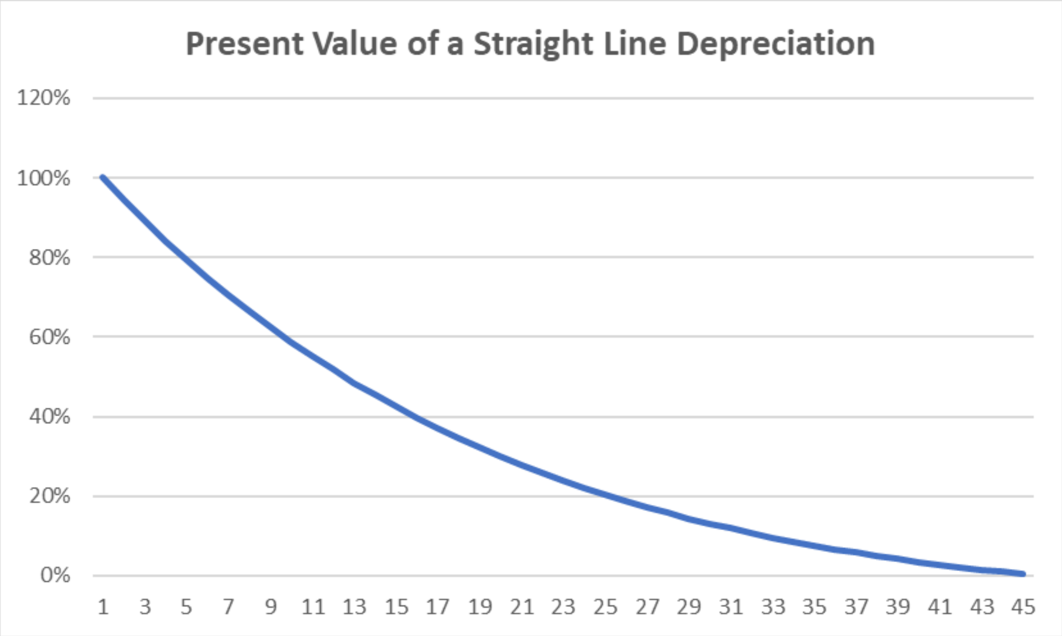
In summary, the application of the useful life value approach involves adding to the RAB the present value of the difference between depreciation of the new assets and the depreciation of the existing assets they replaced. While the replacement of older assets does not guarantee that the investment is prudent and efficient, we consider the approach is appropriate in this circumstance.

We have calculated the useful life/residual value by combining two sets of values for the applicable asset categories:

- Best available replacement age profile. An example of this is shown in section A.3.1.2 Figure A.5

- Percentage of present value over time of a straight line depreciation using the associated economic life and discount rate. An example of this is shown in Figure A.6 below.

Figure A.6 Present Value of a Straight Line Depreciate



Source: AER analysis.

These calculations have resulted in a total useful life/residual value of $253.5 million for the 2013–18 period. We note this value is an approximation based on the best verifiable data submitted by Ergon Energy.

Summary of alternative estimate build up

Table A.5 set outs a summary of our alternative estimate build-up.

Table A.5 Summary of alternative estimate build-up

Focus area	Capex ($ mill)	% reduction	Alternative estimate ($mill)	Overspend ($ mill)	Alternative overspend ($mill and % reduction)	Estimation technique
Pole asset	555.5	34.2%	365.8	341.3	151.6 (55.6%)	Benchmarked against Essential Energy's replacement rate over 10 years (2013–2023)
Opp. replacements – pole-related	Pole top 217.7 Service 44.2	34.2%	Pole top 143.3 Service 29.1	Pole top 217.7 Service 44.2	143.3 (34.2%) 29.1 (34.2%)	% reduction applied only to opportunistic replacement. Same % reduction as for pole assets.

Switchgear and Transformer assets	Switchgear 362.6	73.9%	Switchgear 94.6	Switchgear 268.0	0.0 (100.0%)	All overspend expenditure removed
	Transformer 383.9	54.0%	Transformer 176.5	Transformer 207.4	0.0 (100.0%)	
Other assets	252.4	22.5%	195.5	131.0	74.1 (43.4%)	A proportional reduction of the remaining overspend but exclude the areas EMCa found to be reasonable
Pole top and Service – standalone	Pole top 125.5	0.0%	Pole top 125.5	Pole top 16.5	16.5 (0.0%)	Accept
	Service 80.7		Service 80.7	Service 18.4	18.4 (0.0%)	
Conductor asset	199.0	0.0%	199.0	-12.6	-12.6 (0.0%)	Accept
ADD useful life value from early replacement					253.5	To take account of the value of assets replaced early
TOTAL	**2221.5**		**1410.0**	**1231.9**	**674.0 (45.3%)**	

Source: AER analysis.
Note: 'Other assets' includes 'Underground cable asset'.

A.3.2 Property

Our draft decision is to include Ergon Energy's property overspend of $51.7 million into the opening RAB for the 2025–30 period.

Ergon Energy's property overspend represents 4.0% of the total capex overspend. Given property was not a significant driver of the total capex overspend, we undertook a high-level review of Ergon Energy's property overspend. We reviewed the drivers of the overspend and any relevant business cases provided by Ergon Energy.

Table A.6 shows the AER property capex forecast versus Ergon Energy's actuals over the ex-post period. For year 2019–20, Ergon Energy submitted the overspend was due to property capex deferrals from early in the 2015–20 period.[71] It submitted that the remaining overspend in the 2020–25 period was driven by scope changes and cost increases to two major projects: Maryborough and Cairns redevelopments.[72]

71 Ergon Energy, *Capex – Property Ex-Post Review AER briefing*, January 2024.

72 Ergon Energy, *Capex – Property Ex-Post Review AER briefing*, January 2024.

Table A.6 Ergon Energy ex-post property capex overspend 2018–23

	2018–19	2019–20	2020–21	2021–22	2022–23	Total
AER forecast	27.7	17.7	27.3	16.9	10.3	99.8
Ergon Energy actuals	19.3	45.1	33.9	19.1	34.0	151.5
Difference from forecast (overspend)	-8.4	27.4	6.6	2.2	23.7	51.7

Source: Ergon Energy's proposal

Maryborough redevelopment

Ergon Energy submitted that our forecast in the 2020–25 period for rectification works at its Maryborough site was insufficient due the uncertainty of forecasting work with buildings of that age and condition.[73] It subsequently undertook a redevelopment of the site during the 2020–25 period. It submitted that significant issues were uncovered before and during the re-development such as a substantial asbestos discovery and major structural deterioration.[74] Ergon Energy stated these issues showed that any rectification work would have included unforeseen and material cost increases above the AER forecast.[75]

After reviewing Ergon Energy's business case and details about the issues found before and during the redevelopment, we consider Ergon Energy has justified the need to undertake the redevelopment and we accept that the costs are in a reasonable range.

Cairns redevelopment

Ergon Energy submitted the drivers for the Cairns redevelopment overspend related to scope changes and cost increases.[76] It noted the scope changes related to changes in operational requirements such as accommodating additional staff, and safety and amenity requirements.[77]

Ergon Energy submitted that its cost increases were in line with the changes to the property price index (PPI) since the original estimate was completed in 2020.[78] It also submitted that it took steps to mitigate against costs increases during the ex-post period.[79] It reviewed and retested its construction service panel and retested the market where tender pricing did not meet cost expectations. We consider the substantial increase in PPI from 2020 to 2023 was difficult for Ergon Energy to predict due to unprecedented COVID-19 disruptions.

We reviewed Ergon Energy's Cairns redevelopment business case and further information provided about the cost escalations and the need for scope changes. We consider that

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73 Ergon Energy, *Response to information request 005*, April 2024, p. 2.

74 Ergon Energy, *Response to information request 005*, April 2024, p. 3.

75 Ergon Energy, *Response to information request 005*, April 2024, p. 3.

76 Ergon Energy, *Capex – Property Ex-Post Review AER briefing*, January 2024.

77 Ergon Energy, *Response to information request 005*, April 2024, p. 5.

78 Ergon Energy, *Response to information request 005*, April 2024, p. 4.

79 Ergon Energy, *Response to information request 005*, April 2024, p. 2.

Ergon Energy has justified the need for the scope changes and accept that the cost increases were largely outside of its control.

A.3.3 Connections

Our draft decision is to include Ergon Energy's connection capex overspend of $44.2 million into the opening RAB for the 2025–30 period. Table A.7 outlines Ergon Energy's overspend and the amount to be included into its opening RAB.

Table A.7 AER Draft Decision: Ergon Energy ex-post connections capex 2018–23

	2018–19	2019–20	2020–21	2021–22	2022–23	Total
AER forecast	60.9	60.3	49.7	50.2	49.6	270.7
Ergon Energy actuals	50.8	54.7	64.2	58.7	86.5	314.9
Difference from forecast (overspend)	-10.1	-5.6	14.5	8.6	36.9	44.2

Source: Ergon Energy Connection expenditure: Ex-post review period Presentation, January 2024.

Ergon Energy submitted that the main driver for the overspend is due to increased net migration in regional Queensland and the associated increase in new connections.[80] This occurred in last three years in the 2020–21 to 2022–23 period.

In response to our information request, Ergon Energy submitted further information on the actual growth of regional Queensland population[81] and Ergon Energy's actual active customer base data.[82] The increase in customer base is directly proportional to increased population levels over the last three years of the ex-post period.

Ergon Energy also provided evidence of increase in average material unit price for SCS connection stock codes over this period.[83] This is supported by the Australian Construction Industry Forum's data, an independent source, showing the increase in construction expenditure in regional Queensland.[84]

Based on the additional information provided by Ergon Energy, we are satisfied that Ergon Energy's response to increase its connection volumes above the forecast is justified given the circumstances. It is reasonable that Ergon Energy would have incurred additional expenditure in meeting the unanticipated population growth of regional Queensland and unexpected increase in material price levels in construction. These drivers are influenced by external factors outside Ergon Energy's control.

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80 Ergon Energy, *Att. 5.3.01 – Ex post Review of Ergon Energy 2018–2023 Capital Expenditure – Justification Paper*, January 2024, pp 29-30.

81 Ergon Energy, *Response to information request 015 – Referring to actual Australian Bureau of Statistics data from 2015–16 to 2022–23, Question 1*, May 2024.

82 Ergon Energy, *Response to information request 015 – Question 1*, May 2024; Ergon Energy, *Response to information request 052 – Question 1*, July 2024.

83 Ergon Energy, *Response to information request 052 – Question 2*, July 2024

84 Ergon Energy, *Response to information request 015 – Question 1*, May 2024.

A.3.4 ICT

As Ergon Energy will self-fund the ICT capex that it incurred above the AER forecast for the last three years (2020–21 to 2022–23) of the ex-post period, our draft decision does not include Ergon Energy's ICT overspend of $113.6 million in the opening RAB. Therefore, we are including $124.9 million of ICT capex into Ergon Energy's opening RAB for the 2025–30 period. [85] Table A.8 outlines Ergon Energy's overspend and the amount to be included into its opening RAB.

Table A.8 AER Draft Decision: Ergon Energy Ex-post ICT capex 2018–23

	2018–19	2019–20	2020–21	2021–22	2022–23	Total
AER forecast	3.1	7.7	41.3	40.8	39.9	132.7
Ergon Energy actuals	2.8	0.2	96.9	83.6	62.8	246.3
Difference from forecast (overspend)	-0.3	-7.5	55.6	42.8	22.9	113.6
ICT capex to include in the opening RAB	**2.8**	**0.2**	**41.3**	**40.8**	**39.9**	**124.9**

Source: AER analysis

Although Ergon Energy proposes to not recover the expenditure on ICT capex above the amount that was included in the AER forecasts for the ex-post period (and we are therefore not including its ICT overspend in the opening RAB), we still undertook a high-level review of Ergon Energy's ICT overspend.

Ergon Energy submitted that the main drivers for the overspend were a major transformation of its legacy applications and unplanned cyber security expenditure to meet new compliance obligations. [86] It noted the complexity of its major ICT transformation led to challenges that were not anticipated and that this was a major driver of the overspend.[87] Ergon Energy acknowledged that while some of these issues were outside its control (such as economic and COVID-19 factors), some were also within its control resulting in some inefficient spend.[88]

Ergon Energy has undertaken post implementation reports and it noted that in January 2023, the Energy Queensland Board paused the ICT transformation to commence a re-planning phase.[89] It submitted that learnings from its review have been considered in setting the ICT expenditure forecast for the 2025–30 regulatory control period.[90]

85 As Ergon Energy will self-fund its $121.3 million overspend for years 2020–21 to 2022–23, for Ergon Energy's opening RAB, we are including its actual ICT capex from 2018–19 to 2019–20 and the AER forecast from 2020–21 to 2022–23.

86 Ergon Energy, *Att.* 5.3.11, *Capex ex post justification – Non-network ICT*, January 2024, p. 2.

87 Ergon Energy, *Att.* 5.3.11, *Capex ex post justification – Non-network ICT*, January 2024, p. 13.

88 Ergon Energy, *Att.* 5.3.11, *Capex ex post justification – Non-network ICT*, January 2024, p. 12.

89 Ergon Energy, *Att.* 5.3.11, *Capex ex post justification – Non-network ICT*, January 2024, p. 14.

90 Ergon Energy, *Att.* 5.3.11, *Capex ex post justification – Non-network ICT*, January 2024, p. 15.

Based on the information before us, we agree that Ergon Energy faced considerable challenges with scope and governance during the ex-post period that led to the overspend. We also accept that some of these challenges were outside of its control.

We acknowledge Ergon Energy's efforts to learn and adapt during the final stages of its ICT transformation and into the 2025–30 period. Based on Ergon Energy's estimated ICT capex overspend in 2023–24 and 2024–25, we note there is a possibility of another overspend in Ergon Energy's next ex-post period (2023–28).[91] This would allow us to review if Ergon Energy has implemented its learnings to achieve more efficient expenditure.

A.3.5 Capitalised overheads

We have included $56.1 million of Ergon Energy's overspend in capitalised overheads into the opening RAB for the 2025–30 period. This is a reduction of 40.6% relative to Ergon Energy's overspend of $94.4 million in the ex-post period. Based on the information before us, Ergon Energy's overspend appears to be driven by the level of increase in direct costs over the ex-post period.

As repex makes up about 90% of the overspend, we recommend a reduction to capitalised overheads based on a 45.3% reduction of the overspend associated with repex (90% of 45.3% of $94 million).

91 Ergon Energy, *Capex chapter – 2025–30 Regulatory Proposal*, January 2024, p. 117.

B Reasons for decision on key capex categories (ex-ante review)

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

- Replacement expenditure (B.1)
- Augex (B.2)
- Connections (B.3)
- ICT (B.4)
- Resilience (B.5)
- CER integration (B.6)
- Fleet (B.7)
- Property (B.8)
- Capitalised overheads (B.9)

B.1 Replacement expenditure (repex)

B.1.1 AER Draft Decision

We do not accept that Ergon Energy's repex forecast of $2,718.8 million would form part of a total capex forecast that reasonably reflects the capex criteria. Our draft decision includes an alternative forecast of $1,844.3 million which is $874.5 million (or 32.2%) lower than Ergon Energy's proposal.

B.1.2 Ergon Energy's proposal

Ergon Energy's forecast repex is $2718.8 million for the 2025–30 period, 22.4% higher than ex-post period actuals and 11.8% higher than current period actuals/estimates. We note that this step up maintains its higher level of repex where it overspent in the ex-post period, relative to the AER's forecast repex, by 124.5%.

A large part of Ergon Energy's repex program is defect-driven; that is, it is based on the assessed condition of the assets following inspection. Ergon Energy states that its bottom-up forecast is derived using the Condition Based Risk Management (CBRM) methodology, a type of risk-cost modelling. The CBRM is used to predict the asset condition, and is an option used by Ergon Energy as a part of its options analysis. Ergon Energy has implemented the CBRM for the majority of its asset classes. Risk-cost modelling is a feature of good industry practice as noted in the AER's asset replacement industry guidance note.

Ergon Energy provided a business case for each of its major RIN categories of repex. However, we found that the amounts included in Ergon Energy's business case documents do not align with the RIN categories or Ergon Energy's capex model submitted with its regulatory proposal. The discrepancies were material. Following additional information provided by Ergon Energy, EMCa identified that the differences are due to the forecasts being based on historical replacement levels and not based on the risk-cost modelling in the business case, as asserted by Ergon Energy.

B.1.3 Reasons for decision

Based on the information before us, we found that a significant portion of Ergon Energy's forecast repex is not prudent and efficient.

Table B.1 sets out Ergon Energy's forecast by asset and the difference between the forecast relative to the ex-post actuals and current period actuals/estimates. At a top-down level, as can be seen, Ergon Energy is proposing a step up in the forecast relative to ex-post actuals and current period actuals/estimates for several asset categories.

Table B.1 Ergon Energy forecast at the asset level ($ million, $2024–25)

Asset	Ergon Energy 2025–30 forecast	% change from 2018–23 ex-post actuals	% change from 2020–25 actuals/estimates
Poles asset	653.8	17.7%	8.6%
Conductor asset	259.3	30.3%	6.9%
Pole top structure asset	541.0	57.6%	49.8%
Distribution transformer asset	237.8	-32.1%	-19.1%
Distribution switchgear asset	279.6	5.6%	-11.3%
Service asset	150.7	20.7%	3.0%
Substation transformer asset	105.8	215.7%	120.7%
Substation switchgear asset	62.5	-36.1%	-8.5%
SCADA, control and protection assets[a]	225.4	107.5%	34.8%
Other assets[b]	202.9	41.1%	7.9%
Total repex	**2718.8**	**22.4%**	**11.8%**

Source: AER analysis.

Note: (a) Reallocated the operational technology programs in 2025–30 from the 'Other assets' to 'SCADA, control and protection assets'
(b) 'Other assets' includes 'Underground cable asset'

B.1.3.1 Bottom-up review

In this section, we provide:

- a summary of our overall bottom-up observations
- our specific findings at the asset level.

Overall bottom-up observations

In summary, we found that Ergon Energy's forecast repex is not prudent and efficient and materially overstated. We came to this conclusion due to the following findings:

- For most of Ergon Energy's repex forecast, it did not rely on the results of the CBRM or other type of risk-cost modelling. Instead, its forecast is a continuation of the elevated replacement levels in the current period and ex-post period.

While Ergon Energy implemented the CBRM for most of its assets, its forecasts were not based on the CBRM results. Therefore, contrary to Ergon Energy's statements that its forecast is based on risk-cost modelling, like EMCa, we found that its forecast was based on a continuation of its current level of asset replacement for each asset class.

This finding, which was evident in the different numbers presented in the forecast model and the business cases, means that Ergon Energy has placed significant reliance on its most recent historical replacement volumes and expenditure to determine its future requirements. This continues the high levels of replacement activity and expenditure that we consider Ergon Energy has not adequately justified in the ex-post period.

- Ergon Energy's forecast is based on overstated historical replacements levels that are not prudent and efficient

  Ergon Energy has not provided sufficient supporting evidence to demonstrate that its historical replacement volume of works is a reasonable proxy for prudent and efficient future replacement volumes. Our assessment of repex in the ex-post period found that a considerable portion of Ergon Energy's repex was not prudent and efficient. We also note that Ergon Energy has proposed further increases beyond its historical levels, with its forecast repex being 22.4% higher than the ex-post period and 11.8% higher than current period actuals/estimates.

- Ergon Energy's adoption of common Energy Queensland standards has contributed to higher levels of expenditure

  EMCa observes that Ergon Energy made changes to its capex forecasting methods aimed at the integration of processes associated with the establishment of Energy Queensland. This integration and standardisation of methods adopted by Energy Queensland has also contributed to higher forecast expenditure levels. For some assets, like poles, Ergon Energy has applied Energex's pole standards and practices which are not suited to its network. The reasons Energex's pole standards are not suited to Ergon Energy's network are discussed in the ex-post review context in section 5.4 and A.3.1.2 above where Energex's pole standards and practices are for a predominately urban network, with an inherently different risk profile compared to Ergon Energy's network. We note that these reasons continue to apply in this ex-ante assessment.

- Ergon Energy proposes continued high levels of opportunistic replacement in the forecast period that is not prudent and efficient

  We have the same concerns with opportunistic replacement in this ex-ante assessment, as expressed in our ex-post repex review (see section 5.4 and A.3.1.2 above). Ergon Energy has not provided adequate justification for the considerable opportunistic replacement proposed. We acknowledge that opportunistic replacement is good industry practice if it is cost effective to do so. Our review of Ergon Energy's supporting material is that in many incidences, opportunistic replacement has not been cost effective. In particular, we found that Ergon Energy's own analysis demonstrates that in many cases, this activity is associated with a negative cost benefit

- Where Ergon Energy has undertaken a cost benefit analysis, EMCa found errors, incorrect application of the counterfactual that biases towards Ergon Energy's preferred option, and overstated benefits.

EMCa found that Ergon Energy's counterfactual is a continuation of Ergon Energy's current practice where the CBA provides no assessment of the net benefits of its proposal. Instead, the CBA assumes (without demonstrating this) that the current policy has a net benefit and then measures only the variance in NPV of standardised alternative options relative to this.

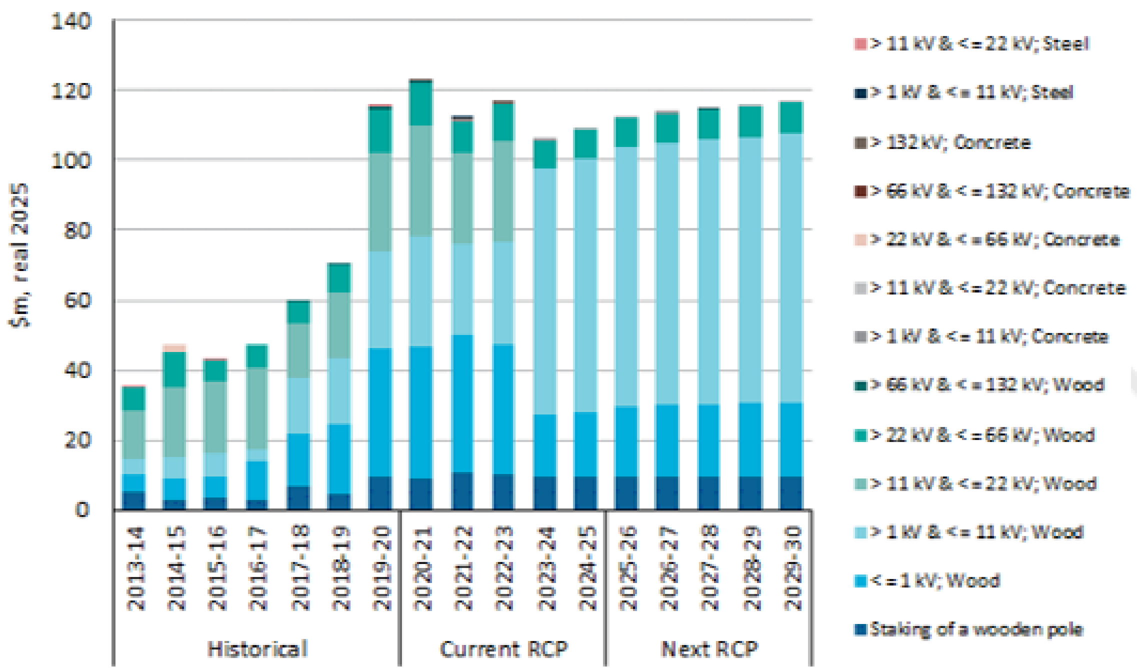
Further, Ergon Energy claims the same benefits multiple times. For instance, EMCa found that in the CBA for service lines, the claimed benefits of a reduction in risk from improved service line safety are the same as those in its network visibility business case, as well as those in its pole and pole top structure. As a result of multiple counting of the same benefit, this makes its estimated $1 billion of total benefits to continue its current replacement program invalid.

Specific findings at the asset level

Pole asset

Ergon Energy's forecasts $653.8 million for pole replacement for the 2025–30 period. This amount includes replacement for opportunistic purposes. Its forecast is $98.3 million (or 17.7%) higher than its actuals in the ex-post period or $51.8 million (or 8.6%) higher than actuals/estimate in the current period. This step up can be seen in Figure B.1 which shows the historical and forecast poles trend.

Figure B.1 Historical and forecast poles trend



Source: EMCa, *Ergon Energy 2025/26 to 2029/20 Regulatory Proposal, Review of Aspects of Proposed Expenditure*, September 2024, p. 94.

We found that Ergon Energy's supporting documentation did not demonstrate prudency and efficiency of its poles forecast. In particular:

- EMCa found that Ergon's submitted business case, while stating a NPV positive outcome, does not demonstrate how its selected option (the counterfactual being the current historical program) is optimal or reflects optimal timing. There are also major errors in its business case where it is assumed that there are net benefits from the counterfactual without testing this assumption.

- EMCa observes that Ergon Energy's staking rate of 24% is on the low end compared to other comparable DNSPs.
- A large component of Ergon Energy's poles forecast relates to inefficient opportunistic replacement where Ergon Energy is proposing to replace poles much earlier than its economic life.
- Ergon Energy's proposal to continue its current poles program into the forecast period is predicated on the positive results from the current program. It states:[92]

> These efforts [from its current poles program] have resulted in a significant rise in number of defects identified requiring remedial actions including replacement/reinforcement in commencing 2018–19. Our efforts are starting to yield positive results as reflected in our actual failure rate reduction in recent years. Therefore, our replacement/reinforcement volume is recommended to continue to bring the failure rate below ESCOP levels.

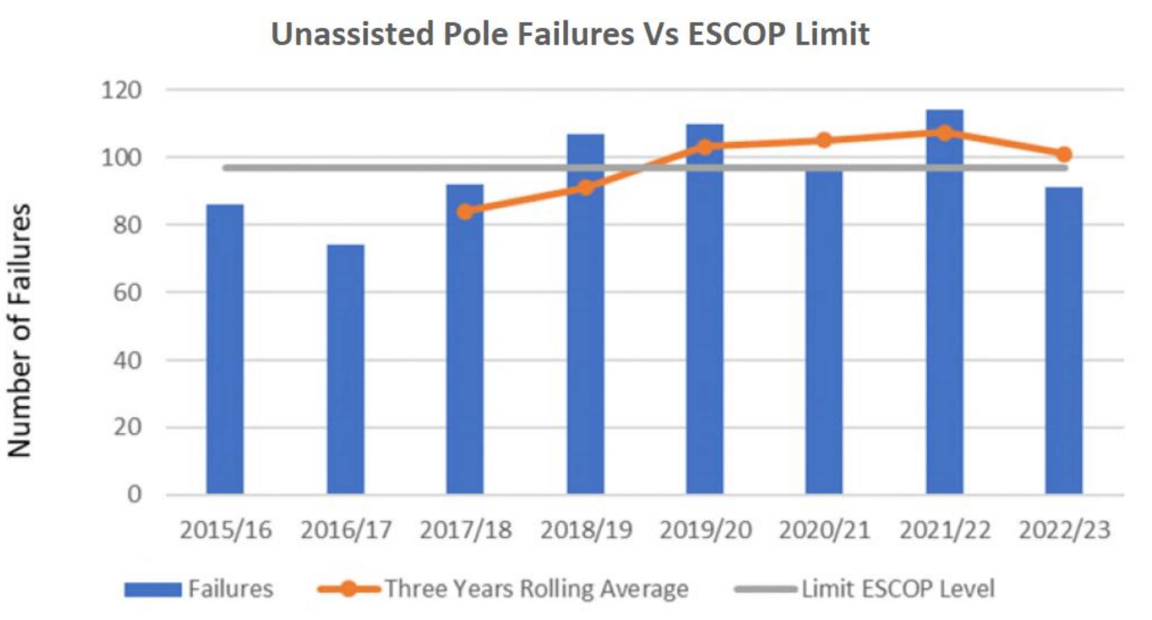
However, we observe that in the most recent years (2020–21 and 2022–23) its unassisted pole failures are falling relative to the years that are driving it to exceed the ESCOP limit. This does not appear to support continued elevated levels of pole replacement into the forecast period. Figure B.2 shows the three-year moving average overtime and the ESCOP's limit.[93] As can be seen, there is an increasing trend in the three-year moving average, but the rate is trending downward by 2022–23.[94]

[92] Ergon Energy, *Att. 5.4.01 - Business Case Pole Replacements*, January 2024, p. 8.

[93] The ESCOP 2020 specifies, amongst other things, a minimum three-year moving average reliability of 99.99 % per annum or an average pole failure rate of 1 per 10,000 poles.

[94] We note the 2021–22 year with the highest rate of unassisted pole failures since 2015–16 coinciding with the major floods and severe storms that occurred in Brisbane and across southern Queensland in early 2022. However, we typically expect unassisted pole failures to exclude failures caused by these exogenous factors.

Figure B.2 Comparison on Ergon Energy's unassisted pole failures against the ESCOP limit



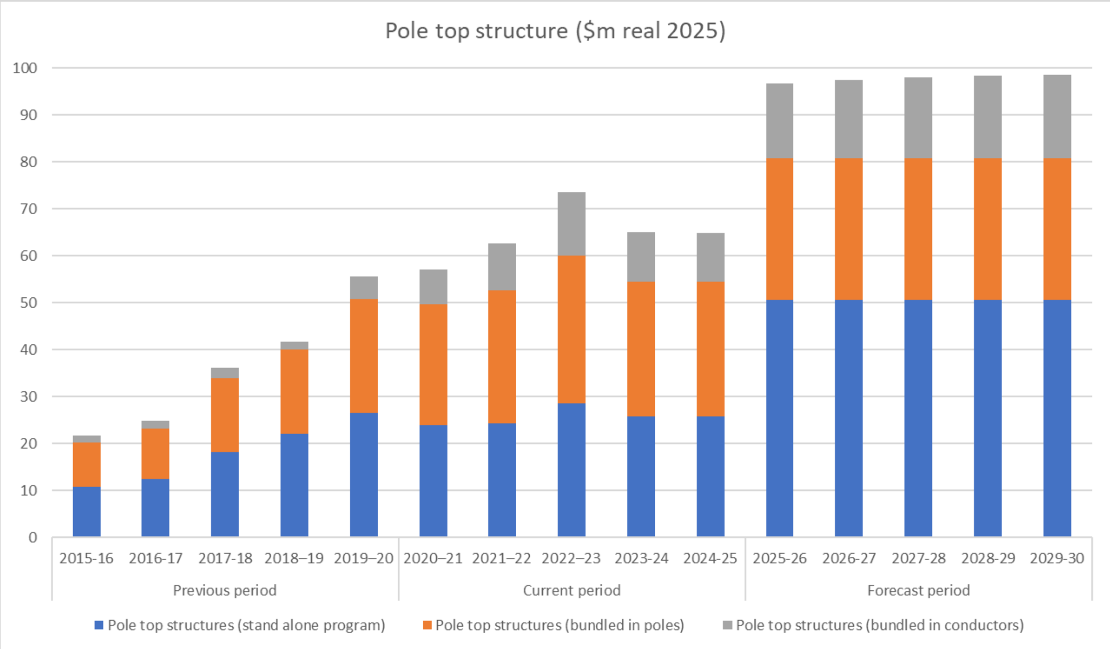
Source: Ergon Energy, *Att. 5.4.01 – Business Case Pole Replacements* – January 2024, p. 24.

Pole top structure asset

Ergon Energy forecasts $541.0 million to replace its pole top structure asset in the 2025–30 period. Its forecast is comprised of a stand-alone program of $262.3 million and opportunistic replacement of $278.7 million. Its total forecast is a material step up from its ex-post period and current period expenditure - $197.8 million (or 57.6%) higher than ex-post period expenditure. In particular, we note that Ergon Energy is proposing an additional 7000 planned replacements per annum, with its stand-alone program to increase from $125.5 million in the ex-post period to $262.3 million in the forecast period.

Figure B.3 shows the overall forecast step up in the 2025–30 period is in both the stand-alone program as well as due to opportunistic replacement.

Figure B.3 Trend in pole top structure expenditure



Source: AER analysis.
Note: We allocated the cost for 2023–24 and 2024–25 based on best available information.

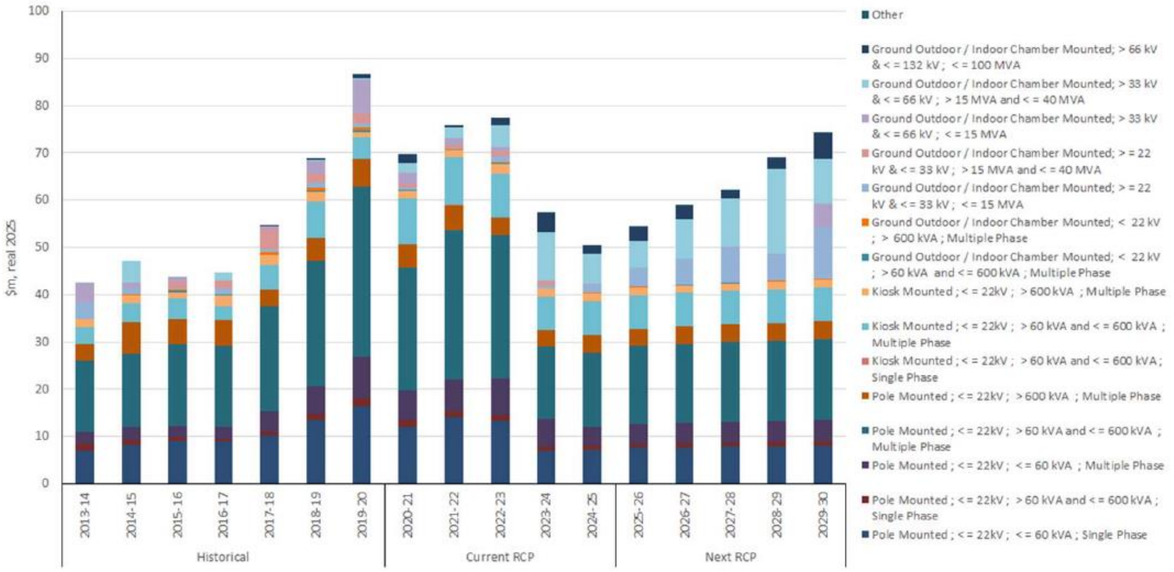
Overall, we found that Ergon Energy did not provide sufficient evidence in support of the prudency and efficiency of its forecast. We found little detail in Ergon Energy's supporting documentation, especially about the reasoning for the material step up in its stand-alone program. EMCa also identified a number of concerns with Ergon Energy's supporting information including its business case. In particular, EMCa placed little weight on the business case as there are several major errors including differing counterfactual volumes, and incorrect modelling.

We encourage Ergon Energy to provide further information on the reasons for the material step-up in the forecast period in its revised proposal.

Distribution transformer asset

Ergon Energy proposes $237.8 million for distribution transformers for the 2025–30 period. Figure B.4 shows the expenditure trend in both distribution and substation transformers over time. As can be seen, Ergon Energy's transformer forecast is similar to the current period, with an increasing trend over the next period. This is the result of a decline in distribution transformer replacement and an increase in substation transformer replacement.

Figure B.4 Trend in transformer expenditure overtime



Source: EMCa, *Ergon Energy 2025/26 to 2029/20 Regulatory Proposal, Review of Aspects of Proposed Expenditure*, September 2024, p. 106.

While Ergon Energy is forecasting a decline in distribution transformer replacement, we consider that Ergon Energy's forecast is not prudent and efficient because there is likely to be a material reduction in the need to replace transformers in the forecast period. This is because:

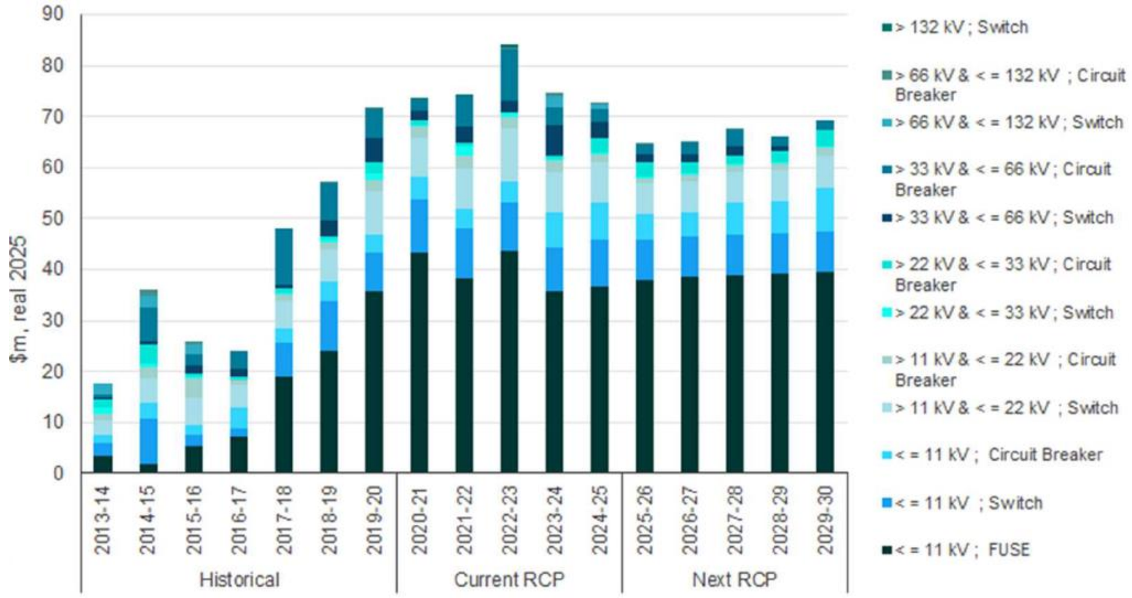
- EMCa notes that in assessing the transformer defect rates in Ergon Energy's business case, these rates are likely to decline in the forecast period. This is because as defect-based pole and conductor replacement proceeds, the opportunistic replacement of transformers is likely to reduce the defect levels below historical levels, as the older transformer fleet is removed from the population
- Ergon Energy introduced a number of significant improvements to its program which are likely to reduce the number of transformer replacements required for different types of defects. EMCa found that these efficiencies have not been accounted for in the increasing trend of the forecast.

Distribution switchgear asset

Ergon Energy proposes $279.6 million for switchgears for the 2025–30 period. Figure B.5 shows the expenditure for both distribution and substation switchgears over time. At a total level, the forecast expenditure for switchgear repex is similar to that incurred during the current period. However, this is a step increase from historical expenditure. Ergon Energy submits that this step up is due primarily to opportunistic replacements when poles and conductors are replaced.[95]

95 Ergon Energy, *Att. 5.3.15 - PIR switch replacements*, January 2024.

Figure B.5 Trend in switchgear expenditure overtime



Source: EMCa, *Ergon Energy 2025/26 to 2029/20 Regulatory Proposal, Review of Aspects of Proposed Expenditure*, September 2024, p. 109.

We consider that Ergon Energy's forecast for switchgears is not prudent and efficient because:

- EMCa observed a decreasing trend of defects compared with historical levels. Therefore, we would expect a reduced forecast in replacement volumes commensurate with these reductions in defects. While Ergon Energy has reduced its volumes to some degree, there is still a step increase relative to the historical period. We encourage Ergon Energy to provide further information about this unexplained increase in its revised proposal
- The benefits of Ergon Energy's opportunistic replacement in the ex-post period have not been accounted for in the forecast. EMCa considers that these benefits would be considered in a risk optimised program and would not result in a step increase relative to the historical period
- the NPV analysis associated with this program contained significant errors where the analysis is designed to maintain the historical level of replacement that can only be the same or higher.

Substation transformers asset

Ergon Energy forecasts $105.8 million to replace 55 substation transformers for the 2025–30 period. This is a material increase compared to the past 10 years.

EMCa noted that Ergon Energy overstated the risks and benefits in its economic analysis in its business case resulting in advancing some projects ahead of their optimal replacement date. As the capex profile is about twice as high at the back of the next period, optimal timing would have a material impact on replacement needs in the next period.

We also observe that the condition data does not support the level of replacement proposed by Ergon Energy. Further, the unit rates appear overstated given the smaller average transformer size in Ergon Energy's network as well as other cost-effective solutions to address condition concerns (such as drying transformers instead of replacement).

Substation switchgear asset

Ergon Energy proposes $62.5 million to replace 263 substation switchgear in the 2025–30 period. This is in line with the level of replacement for the past 10 years.

While Ergon Energy's CBRM only identified 235 substation switchgear for replacement, Ergon Energy noted that bundling the transformers and switchgear together means an additional 28 substation switchgear are brought forward into the next period based on optimised cost and benefit.

Similar to its observation with substation transformers, EMCa notes that Ergon Energy has overstated the risks and benefits in its economic analysis resulting in advancing some projects ahead of their optimal replacement date. We concur with EMCa, and consider the additional 28 substation switchgear replacements have not been considered in an optimised portfolio of work. We consider Ergon Energy can manage and re-prioritise its substation replacement portfolio within the 235 substation switchgear replacements even if bundling is efficient.

SCADA, control and Protection assets

Ergon Energy forecasts $225.4 million for SCADA, control and protection assets for the 2025–30 period. This forecast is comprised of protection relay program ($110.5 million), operational technology and communication programs ($114.8 million).

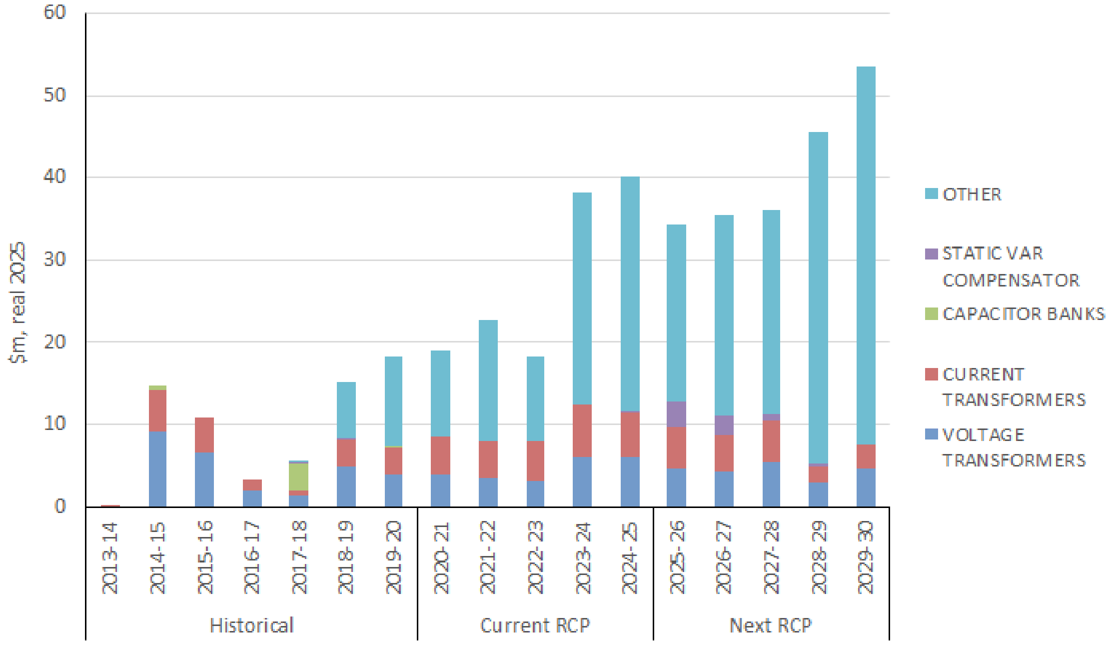
EMCa noted the method used by Ergon Energy to derive its forecast replacement volumes for its protection relay replacement is sound and considers the forecast to be reasonable.

However, EMCa found a number of Ergon Energy's proposed operational technology and communication programs to not be well-supported. This includes the grid communications program, one of the larger programs forecast at $89 million, where EMCa was unable to determine if the proposed repex is based on the outputs from Ergon Energy's risk-cost analysis.

Other assets

Ergon Energy proposes $202.9 million for 'other assets' in the 2025–30 period. Figure B.6 shows the trend in expenditure in 'other assets'. The 'other assets' category was first introduced in 2019 and the associated repex has increased over time, with a further step increase in 2024 prior to the commencement of the 2025–30 period.

Figure B.6 Trend in 'other assets' expenditure overtime



Source: EMCa, *Ergon Energy 2025/26 to 2029/20 Regulatory Proposal, Review of Aspects of Proposed Expenditure*, September 2024, p. 119.

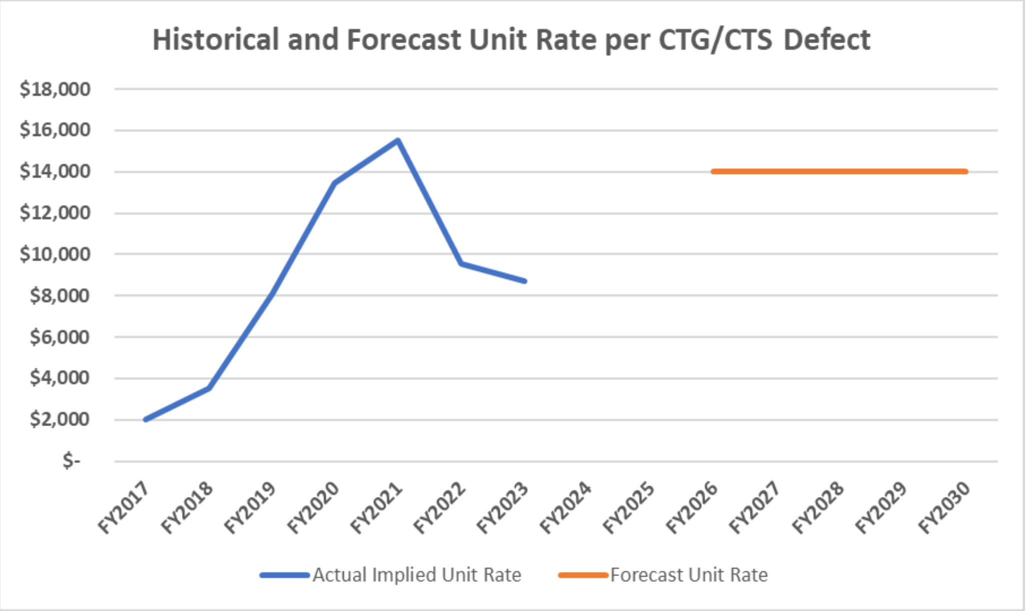
We discuss our findings on Ergon Energy's forecast for the largest programs that make up the 'other assets' category below:

- Return to service (RTS) program which contributes $80.7 million – Ergon Energy re-submitted a lower estimate of $57.7 million, after we identified an error with its forecasting methodology. Its lower estimate is close to our alternative forecast.
- Instrument transformer program which contributes $41.7 million - EMCa observed that any increase (or decrease) in substation replacement projects (discussed above) is directly related to increases (or decreases) in replacement of instrument transformers. We have had regard to this correlation in coming to our alternative forecast.
- Transmission tower program which contributes $21.9 million - EMCa found that the business case did not demonstrate prudency and efficiency of the forecast. In particular, it noted that Ergon Energy's towers are experiencing low failure and defect rates and the step up in forecast expenditure for tower treatment is not explained. Further, the NPV analysis in the business case overstates the risk.
- Transformer bunding program (oil containment) which contributes $18.2 million – EMCa found that the forecast was not adequately justified. In particular, the associated NPV analysis overstates the probability of an oil spill event, with no evidence to support that probability. EMCa also noted the timing to achieve compliance for these types of programs is typically 10 or more years while Ergon Energy is aiming to achieve compliance in 7 years.
- Underground assets which contributes $41.2 million – EMCa found that the proposed replacement volume is not adequately supported where there is material inconsistency between the business case and the forecast model. While we note EMCa's concerns, Ergon Energy's proposed expenditure is in line with its ex-post actual of $38.8 million which we have accepted.

Clearance-to-Ground/Clearance-to-Structure (CTG/CTS)

Ergon Energy proposes $181.1 million for its CTG/CTS program for the 2025–30 period. Figure B.7 shows Ergon Energy's historical and forecast unit rates for its CTG/CTS program. As can be seen, while the unit rates in FY2022 and FY2023 have declined, Ergon Energy proposed a forecast unit rate that is close to the peak of the program. EMCa also observes that Ergon Energy's proposed unit rates are overstated as it expects more defects can be addressed through lower cost options such as re-tensioning of the conductor.

Figure B.7 CTG/CTS historical and forecast unit rate per defect ($, $2024–25)



Source: AER analysis.

EMCa notes that Ergon Energy's volumes are elevated in the forecast period although we also note that Ergon Energy has compliance obligations under the *Electrical Safety Regulation 2013* (Qld) on clearance limits and that this program is safety related.

B.1.3.2 Alternative forecast

At this stage, our alternative forecasts are a mix of bottom-up and top-down approaches reflecting the information before us.

We applied a top-down approach – benchmarking Ergon Energy's replacement rate against Essential Energy's – in deriving the alternative forecast for poles, distribution transformers and switchgears. Due to our concerns with the poor quality of information and data provided to us by Ergon Energy, we have had to explore different avenues to derive an alternative estimate. We undertook comparative analysis between Ergon Energy and other DNSPs and found Essential Energy as the best available business to compare with Ergon Energy because it faces similar challenges with the age and conditions of its poles. We found that Ergon Energy and Essential Energy have similar pole composition and operating environment factors (similar rainfall and humidity levels) that are likely to impact age and condition of their pole populations. We also expect age and condition to be similar for switchgear and transformer assets albeit with a lesser impact from environmental factors.

In applying this approach, we have erred on the conservative side as we did not benchmark Ergon Energy against other potential comparators such as AusNet and Powercor which have a regional component to their service area. We note that Ergon Energy would have performed worse if we included these businesses because of their longer replacement lives. We also did not take account of Ergon Energy's younger asset lives in our benchmarking (see Table A.3) and did not pursue concerns raised by EMCa about Ergon Energy's inefficiently high unit costs in some areas[96] and the overspend in the stand-alone programs for pole top structures and services.[97]

For the rest of this section, we set out:

- How we derived our alternative forecasts.
- Why an additional reduction (beyond reductions in the relevant repex categories) of $79.7 million to forecast repex is required. This is due to early replacements in the ex-post period reducing the repex requirement in the 2025–30 period.
- a summary of our alternative forecasts.

Alternative forecasting method

Poles

Our alternative forecast is $345.9 million which is $307.9 million (or 47.1%) lower than Ergon Energy's proposed forecast of $653.8 million.

Our alternative forecast is based on applying Essential Energy's replacement rate of 3.95% for the past 5 years (2018–23). Table B.2 provides a comparison of customer density and pole characteristics between Queensland and New South Wales DNSPs.

Table B.2 Queensland and New South Wales DNSP timber pole replacement rates

	Average 5 Years Replacement Rate of Timber Poles			
	2013–18	2018–23	2019–24 (NSW) 2020–25 (QLD)	2024–29 (NSW) 2025–30 (QLD)
Ergon Energy	2.55%	7.45%	8.25%	8.40%
Essential Energy	3.50%	3.95%	4.00%	4.90%
Powercor	2.19%	4.93%	n/a	n/a
AusNet	4.48%	4.21%	n/a	n/a
Energex	7.43%	3.62%	3.35%	2.55%
Endeavour	2.40%	3.35%	3.15%	3.70%
Ausgrid	2.99%	2.18%	2.15%	2.30%

Source: AER analysis

We consider applying Essential Energy's replacement rate in 2018–23 is reasonable because:

- Essential Energy's actual and forecast BAU (condition driven) replacement rates have been relatively stable for more than 15 years, noting that the 4.9% replacement rate in 2024–29 includes its resilience pole program

96 EMCa, *Ergon Energy 2025/26 to 2029/20 Regulatory Proposal, Review of Aspects of Proposed Expenditure*, September 2024, pp. 78-80.

97 EMCa, *Ergon Energy 2025/26 to 2029/20 Regulatory Proposal, Review of Aspects of Proposed Expenditure*, September 2024, p. 66.

- We have not used the forecast replacement rates as it is more robust to use actual replacement rates to determine an alternative forecast
- We consider it reasonable to not include a further ‘catch up’ period to address any outstanding pole defect issues. This is because Ergon Energy commenced its shorter pole inspection cycle in 2018 and any catch up in pole replacements would have been completed by the end of the current 2020–25 period (after 8 years)

We also consider that our alternative forecast is conservative as it does not take account of the fact that Ergon Energy poles are younger than Essential Energy’s and using the replacement rate of other NSW DNSPs would mean an even lower capex forecast for Ergon Energy.

A reduction due to poles-related opportunistic replacement

We also note that given our alternative poles forecast is a reduction to Ergon Energy’s poles forecast, this in turn means a reduction to opportunistic replacement associated with pole replacement.

We have applied the same percentage reduction (47.1%) we applied to poles to other assets (pole top structures and services) that are forecast to be opportunistically replaced. We have therefore reduced Ergon Energy’s forecast of opportunistic replacement of pole top and service assets from $341.8 million to $180.8 million ($131.3 million for pole top structures and $29.7 million for services).

Pole top structures (standalone program)

Our alternative forecast is $138.1 million, a reduction of $124.2 million (47.4%) to Ergon Energy’s standalone program of $262.3 million. This is based on applying Essential Energy’s pole top structure expenditure for 2018–23 adjusting for the difference in asset population between networks. We note that our alternative forecast is in line with:

- Ergon Energy’s historical stand-alone pole top structure expenditure in 2018–23
- Our alternative pole forecast percentage reduction (47.1%).

We have already made reductions due to inefficient opportunistic replacement of pole top structures and services through our reductions to its pole forecast as discussed above. Our total alternative forecast for pole top structures is $285.5 million ($138.1 million stand-alone replacements plus $147.4 million opportunistic replacements).

Distribution transformers and switchgear assets

Our alternative forecast for distribution transformers is $183.2 million, $54.6 million (23.0%) lower than Ergon Energy’s forecast of $237.8 million.

Our alternative forecast for distribution switchgear is $230.1 million, $49.5 million (17.7%) lower than Ergon Energy’s forecast of $279.6 million.

We derived our forecast by benchmarking Ergon Energy’s replacement rates with Essential Energy’s (See Table B.3 and B.4). For distribution transformers, we replaced Ergon Energy’s forecast replacement rate of 6.4%, with Essential Energy’s rate of 5%. For distribution switchgear, we replaced Ergon Energy's forecast replacement rate of 4.7% in 2018–23 with Essential Energy's rate of 3.9%.

Table B.3 Queensland and New South Wales DNSPs weighted average age (years)

2023	LV and HV Distribution Assets (i.e. <=22kV only)	
Weighted Average Age	Transformers	Switchgears
Ergon Energy	23	18
Essential Energy	30	23
Energex	18	15
Endeavour	23	26
Ausgrid	27	23

Source: AER analysis including annual CA RINs

Table B.4 Queensland and New South Wales DNSPs 2018–23 replacement rates

2018–23	LV and HV Distribution Assets (i.e. <=22kV only)	
5 Years Replacement Rate	Transformers	Switchgears
Ergon Energy	9.1%	11.6%
Essential Energy	5.0%	3.9%
Energex	5.0%	3.6%
Endeavour	0.7%	5.7%
Ausgrid	0.8%	4.3%

Source: AER analysis including annual CA RINs

Substation transformer and switchgear assets

Our alternative forecast for substation transformers is $77.0 million, $28.9 million (27.3%) lower than Ergon Energy's forecast of $105.8 million.

While Ergon Energy proposed to replace 55 substation transformers in the 2025–30 period, we have examined the risk analysis submitted by Ergon Energy for the top 72 transformers with the highest health/risk index at the end of the 2025–30 period. The test data shows:

- 10 transformers with signs of deterioration that may need replacement within the next 10 years;
- A further 30 transformers with signs of high moisture content that may need interventions within the next 10 years. These interventions may include drying, refurbishment or replacement.

While we consider that Ergon Energy's proposed unit costs are high given its smaller transformer capacity and not every transformer requiring full replacement, we have derived our alternative estimate based on 40 (10+30) out of a proposed 55 transformers (or 72.7%). Based on the information before us, we are of the view that only 40 transformers would require intervention in the 2025–30 period based on the submitted test data.

Our alternative forecast for substation switchgears is $55.9 million, $6.7 million (10.6%) lower than Ergon Energy's forecast of $62.5 million.

While Ergon Energy's CBRM only identified 235 substation switchgear for replacement in the 2025–30 period, it stated that optimising cost and benefit means an additional 28 substation switchgear replacements are also brought forward into the 2025–30 period. We have derived our alternative estimate based on the removing 28 substation switchgear replacements (or 10.6%) from the forecast. EMCa consider the additional 28 substation switchgear replacements have not been considered in an optimised portfolio of work. We are of the view that Ergon Energy can manage and re-prioritise its substation replacement portfolio within the 235 substation switchgear replacements even if bundling is efficient.

SCADA, control and protection assets

Our alternative forecast for SCADA, control and protection assets are $181.7 million, $43.6 million (19.3%) lower than Ergon Energy's forecast of $225.4 million. We have derived our alternative forecast the following way:

- Protection relay program – We have accepted Ergon Energy's proposed forecast.
- Operational technology and communication programs – We have derived a 38% reduction based on EMCa's review on some of the key programs.

We note that it has been a challenge for us to reconcile this asset category as there are numerous projects and programs overlapping between asset categories and capex drivers. While Ergon Energy has re-submitted its forecast to remove some of the double counting, we encourage Ergon Energy to provide this information to us in a more accessible format in its revised proposal.[98]

Other assets

Our alternative forecast is $184.4 million, $18.5 million (or 9.1%) lower than Ergon Energy's forecast of $202.9 million. We derived our alternative forecast in the following way:

- Return To Service (RTS) program - We have accepted Ergon Energy's re-submitted lower forecast.
- Instrument transformer program – A pro-rata reduction of this program, applying the reduction for substation switchgear and transformers. Our alternative estimate is $30.0 million, $11.7 million (or 28.0%) lower than Ergon Energy's forecast of $41.7 million.
- Transmission tower program – We have accepted the forecast associated with this program. While we note EMCa's concerns, we also acknowledge that Ergon Energy's transmission towers are its oldest assets with a weighted average age of between 36 to 47 years. We have had regard to the age of its towers in coming to our position.
- Transformer bundling program – Ergon Energy proposes to meet compliance in 7 years by establishing 79 bunds in the last two years of this period and the remaining 83 bunds in the 2025–30 period. Given Ergon Energy have already prioritised its highest risk sites this period, we do not consider it is prudent to finish this program next period. Our

98 Ergon Energy, *Amendments to Ergon Energy Network's 2025–30 Regulatory proposal SCS Capex model*, June 2024.

alternative estimate of $11.4 million based on spreading the remaining program proposed in the 2025–30 over 8 years instead of 5 years resulting in a 37.5% deferral.

- Underground asset – We have accepted the forecast associated with this program.

CTG/CTS

Similar to our ex-post approach, the reduction to the CTG/CTS program is not obvious in Table B.5 below, as this program involves a number of assets and we took an overall reduction across these affected asset classes.

Using our top-down approach at the asset level, our alternative overspend estimate for CTG/CTS is $105.7 million which is $75.4 million (or 41.6%) lower than Ergon Energy's forecast of $181.1 million.

To verify the top-down estimate, we used a separate method to come to another alternative estimate based on our position of accepting Ergon Energy's volume forecast but applying a lower unit rate. As we consider that clearance gaps less than 20cm can be addressed via re-tensioning, we derived the cost to re-tension where the clearance gaps were less than 15cm. This is about 46% of all clearance gap defects. We then applied the re-tension cost of $1,100 rather than Ergon Energy's cost of $13,000 to that 46%, applying Ergon Energy's $13,000 cost to the remaining 54%. This resulted in the reduction to its clearance program by 41.8%. This is in line with our top-down asset level adjustment of 41.6%.

We consider our alternative estimate is conservative given the observed reduction in both the defect volume and unit rate over time as we would expect fewer defects will be identified next period and the identified defects will likely be dominated by low priority breaches with minimum clearance gaps.

Implications in the forecast period due to early replacements in the ex-post period

We have accepted some overspend in the ex-post review where assets have been replaced earlier than their economic life. This means that some replacement requirements in the 2025–30 period have already taken place (been brought forward) in the ex-post period. It does not appear that Ergon Energy has taken the effect of the early replacement of its assets into account in its forecast.

We consider this approach is consistent with our useful life value approach where we are rolling about 75% of the expenditure into the RAB for assets that have been replaced 5 years early. In the absence of this approach, we would be providing a further 100% of the expenditure in the 2025–30 period for assets that has already been replaced 5 years earlier and recognised in the 2025–30 opening RAB.

To derive the appropriate reduction to the forecast period to avoid double-counting, we used the same information as the useful life value analysis (see Box 2). Similar to our useful life value calculation, we approximated that about 13.4% of poles and 16.3% of distribution transformers and switchgears are being replaced 5 years early during the ex-post period. In total, this resulted in a further reduction of $79.7 million to the total repex forecast.

We consider this is a conservative estimate as we have not considered any potential early replacements in the FY2024 and FY2025 years, which are estimate years.

Summary of our alternative forecasts

Table B.5 summarises our alternative forecasts.

Table B.5 Ergon Energy's forecast by asset and our recommended alternative forecast

Asset/program	Ergon Energy forecast	Alternative forecast	$ mill and % reduction	Alternative forecast method
Poles asset	653.8	345.9	-307.9 (47.1%)	Benchmarked against Essential Energy
Pole top (standalone program)	262.3	138.1	-124.2 (47.4%)	Benchmarked against Essential Energy
Opportunistic replacement with poles – pole top and services	341.8	180.8	-161.0 (47.1%)	Same % reduction as poles, as flow-on impact from pole reduction
Conductor asset	259.3	259.3	0 (0%)	Accept
Distribution switchgear asset	279.6	230.1	-49.5 (17.7%)	Benchmarked against Essential Energy
Distribution transformer asset	237.8	183.2	-54.6 (23.0%)	Benchmarked against Essential Energy
Substation transformer asset	105.8	76.9	-28.9 (27.3%)	Top-down and Bottom-up analysis
Substation switchgear asset	62.5	55.8	-6.7 (10.6%)	Top-down and Bottom-up analysis
Service line (standalone program)	87.6	87.6	0 (0%)	Accept
SCADA, control and protection	225.4	181.8	-43.6 (19.4%)	Top-down and Bottom-up analysis
Other assets	202.9	184.4	-18.5 (9.1%)	Top-down and Bottom-up analysis
Further reduction for flow-on impact from ex-post early replacement		-79.7	-79.7	Top-down analysis
Total repex	**2718.8**	**1844.2**	**-874.5 (-32.2%)**	

Source: AER analysis.

Note: Reallocated the operational technology programs from the 'Other assets' to 'SCADA, control and protection assets' 'Other assets' includes 'Underground cable asset'.

B.2 Augmentation Expenditure (augex)

B.2.1 AER's draft decision

We do not accept that Ergon Energy's augex forecast of $513.2 million would form part of a total capex forecast that reasonably reflects the capex criteria. Our draft decision includes $429.2 million in augex, which is $84.0 million (or 16.4%) lower than Ergon Energy's proposal. This reduction includes a $50.1 million reduction to distribution growth augex, and a reduction of $33.5 million reduction to grid communications, protection and control augex.

B.2.2 Ergon Energy's proposal

Ergon Energy proposed an augex of $788.6 million.[99] Ergon Energy submitted a revised capex model on 28 July, which included a reduction of $84.1 million dollars due to the removal of some projects and an addition of $59.0 million for new and resubmitted projects. These changes resulted in an updated proposed augex amount of $763.4 million[100], which represents 13.4% of total forecast capex.

We consider that $250.4 million of the proposed augex is actually replacement expenditure, cyber or resilience expenditure, and we have assessed these as such. The Clearance to ground (CTG) and Clearance to structure (CTS) programs are not included in our augex assessment for Ergon Energy as it has historically classified these programs under repex and we have classified these as repex for our ex-post and ex-ante review.

For the purpose of our assessment, we have assessed the remaining $513.2 million as augex and refer to this amount for the remainder of this section. This includes sub-transmission growth of $188.6, distribution growth of $216.6 million, grid communications protection and control of $94.0 million and, reliability of $14.0 million.

The proposed augex of $513.2 million is $129.5 million (or 74.7%) higher than Ergon's expected current period augex of $293.7 million on a like-for-like basis.

Ergon Energy's submitted that the key drivers for the uplift in augex are strong demand growth, compliance obligations, and network control and monitoring initiatives.[101]

B.2.3 Reasons for decision

When assessing Ergon Energy's augex proposal, we had regard to major project business cases, key assumptions, identification of need, historical comparison, options analysis, cost-benefit analysis, and the further supporting information provided by Ergon Energy. EMCa also reviewed the prudency and efficiency of the proposed expenditure for CTG/CTS and grid communications, and protection and control.[102]

Table B.6 shows a comparison of proposed augex between the 2020–25 and 2025–30 regulatory periods. Ergon Energy has not submitted consistent categories between the two

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99 Ergon Energy, *2025–30 Regulatory Proposal*, January 2024, p 99.

100 Ergon Energy, *Response to information request 048 – Question 1*, June 2024

101 Ergon Energy, *2025–30 Regulatory Proposal,* January 2024, p. 100.

102 EMCa, *Review of Ergon 2025/26 to 2029/30 Regulatory Proposal*, September 2024.

periods, so this is breakdown is based on AER analysis of Ergon Energy's proposed projects.

Table B.6 Current and forecast period augex by sub-category ($ million, $2024–25)

Sub- categories	2020–25	2025–30	2025–30 $ change	2025–30 % change
Distribution Growth	137.1	216.6[b]	79.4	57.9%
Reliability	17.1	14.0	-3.1	-18.0%
SCADA, Protection and Control	64.0	94.0[c]	30.0	46.9%
Sub-Transmission Growth	75.5	188.6[d]	113.1	149.7%
AER assessed augex[a]	**293.7**	**513.2**	**219.5**	**74.7%**
Replacement	**200.2**	**181.1**	**-19.1**	**-9.5%**
Resilience	**10.5**	**53.1**	**42.6**	**407.6%**
Cyber security	**0.0**	**16.1**	**16.1**	**0.0%**
Grand Total	**504.3**	**763.4**	**259.1**	**51.4%**

Note: (a) AER assessed augex reflects our classification. Replacement, cyber security and resilience expenditure have been assessed separately.
(b) Original proposed amount was $219.9 million, revised to $216.6 million following revised capex model.
(c) Original proposed amount was $128.9 million, revised to $94.0 million following revised capex model.
(d) Original proposed amount was $182.6 million, revised to $188.6 million following revised capex model.

The largest increase is 149.7% million in the sub-transmission growth category. This is driven by a large increase in proposed demand driven projects. There is also an increase in grid communications, protections and control of 46.9% million and distribution growth of 57.9%. The reliability category has reduced by 18.0% since the last period.

We have focussed our assessment on the three augex categories that have increased in the forecast period.

From our bottom-up review of Ergon Energy's major augmentation project business cases we consider that, aside from the distribution feeder augmentation maintain reliability project ($50.1 million), the projects in the sub-transmission growth and distribution growth categories are prudent and efficient investments. Ergon Energy assessed investment options using reasonable assumptions and provided options analysis.

Ergon Energy's reliability category is made up of its worst performing feeder program. We consider that this project is a prudent and efficient investment. The business case sufficiently described the need for investment with reasonable assumptions. This project is at a similar cost to historical levels.

The two areas we didn't think the proposed augex was efficient and prudent were:

- The Distribution feeder augmentation maintain reliability project is justified by worsening reliability performance, however we found that over a longer timescale reliability.

performance has been improving. In addition, the heightened level of constructions in recent years has introduced volatilities in reliability performance requiring further explanation (including a root cause analysis) from Ergon Energy.

- Grid communications, protections and controls contained several projects that we and EMCa consider have not been adequately justified.

We discuss these two areas in more detail below.

Distribution Feeder Reliability

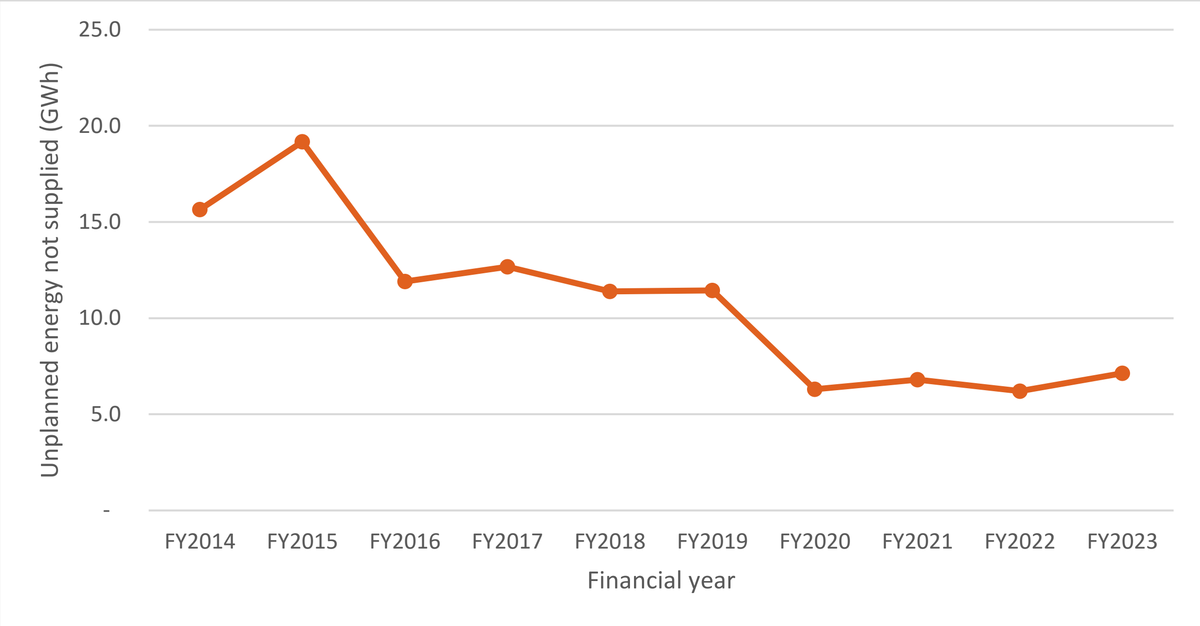
Ergon Energy has submitted a Distribution Feeder Augmentation Maintain Reliability ($50.1 million) project which is included in the distribution growth category. This project aims to maintain the level of reliability for unplanned outages. A key component of our analysis of this project involved making sure that the project was maintaining reliability and not improving base level reliability. We issued an information request to Ergon Energy for evidence that this project maintains reliability for unplanned outages.

In response to our information request, Ergon Energy provided a chart and explanation to show that it is not improving base level reliability performance with this project. It claimed that based on its graph, unplanned reliability performance is trending upwards in terms of Energy Not Supplied, which illustrates the program is targeted to address this trend and not improve base level reliability.[103]

We have identified two issues with Ergon Energy's analysis. Firstly, although it has identified an increase in unplanned energy not supplied from 2018 to 2023, this is a short time series to examine the trend for a highly volatile series. 2018 was a significantly low year for unplanned energy not supplied. We have examined a longer time series and taken a rolling average as seen in Figure B.7. As the data is quite volatile, we have used a 5-year rolling average to bring out the underlying movement in the data series. Our chart shows a clear downwards trend since 2014 which is not in line with Ergon Energy's analysis.

[103] Ergon Energy, *Response to information request 008 – Question 4*, April 2024.

Figure B.7 Ergon 5 year rolling average unplanned energy not supplied



Source: AER analysis

Based on our analysis we have determined that Ergon Energy's suggested increase in unplanned energy not supplied is a result of the selective choice of data used in their analysis (the 6 years chosen).

We have also checked against SAIDI and SAIFI and found that SAIDI and SAIFI were not increasing.

Secondly, although Ergon Energy identified unplanned energy not supplied as the driver, this program also appears to be addressing the increase in planned energy not supplied. We note that the increase in planned energy not supplied is in part due to the increased level of construction activity across Ergon Energy's network and should not be addressed as part of this additional reliability investment. We discuss the issue of planned and unplanned outages in section B.5 on resilience.

We consider that based on our analysis there is no increasing trend in reliability for unplanned energy not supplied and therefore there is no justification for any of the costs for this project. We therefore did not include any costs for this project.

Grid communications, protections and controls

Ergon Energy has proposed $94.0 million for 56 projects relating to grid communications, protection and control. These projects are aimed at improving the reliability and safety of Ergon Energy's network. Ergon Energy's proposal for this category is an increase of $30.0 million (46.9%) from the current period estimate of $64.0 million. However, Ergon Energy states that the accuracy and subsequent reliance on historical data to be low. As a result, we have focused our analysis on a bottom up approach rather than trend analysis. Ergon Energy also refers to this sub-category as grid technology, or as SCADA, protection and control.

We engaged EMCa to assess Ergon's grid communications, protections and controls.[104] Our assessment is informed by the findings in EMCa's report.

The following project groupings were sourced from EMCa's report, noting that Ergon Energy were unable to obtain a project list that reconciled with the augex data in the capex model:

- Grid communication projects that increase automation of the network
- Grid control projects that are intended to improve visibility
- Protection projects driven by safety and compliance
- Operational technology and Intelligence grid enhancements that advance Ergon Energy's technological systems to improve maintenance of the network.

On 28 July 2024, Ergon Energy submitted a revised capex model which resulted in a net reduction of $32.1 million to grid communications, protections, and control. Previously proposed projects such as the $28.7 million Grid Communications Asset Enhancements project were removed from Ergon Energy's proposal.

We consider that Ergon Energy's forecast for grid communications, protection and control sub-category expenditure is overstated. Our position, informed by EMCa's review, is to reduce grid communications, protection, and control by $33.5 million to an alternative forecast of $60.5 million. Throughout our analysis, we have engaged with Ergon Energy through information requests and meetings. While we appreciate Ergon Energy responding to our requests for information, we found that the supporting evidence was unable to sufficiently address the reoccurring issues in its augex proposal. These include an overall lack of overarching strategy, minimal options analysis, and deliverability concerns. We acknowledge the need for investments by networks to support a safe and reliable network. However, without enough supporting evidence, we were unable to accept Ergon Energy's proposed augex for this category as reasonably reflecting the capex criteria. Our alternate forecast considers where there is sufficient information to support its business case. Without enough evidence, we are unable to accept the project into our forecast. For projects that have deliverability concerns, we have adjusted the project forecast to ensure deliverability during the forecast regulatory period.

We discuss below in further detail the key issues we and EMCa identified in Ergon's proposal:

- Lack of overarching strategy for the protections projects
- Insufficient options analysis for the grid communications projects
- concerns about the deliverability of the DC and Bus overcurrent protection duplication projects
- Concern that the basis for the backup reach protection improvement program is incorrect.

Overarching strategy

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[104] EMCa, *Review of Ergon 2025/26 to 2029/30 Regulatory Proposal*, September 2024, pp. 128-164.

We are not satisfied that Ergon Energy's proposed $34.9 million for its protections projects reflects the capex criteria. One of the findings from EMCa's report was a lack of an overall strategic approach when formulating Ergon Energy's protection projects.[105] While Ergon Energy included the Future Grid Roadmap (the Roadmap) as one of its supporting documents, it lacks specific details to be an informative guide. We consider that the absence of an overarching approach has contributed to inefficient management of its protection programs.

From the protection projects Ergon Energy proposed, we were unable to find evidence that Ergon Energy considered efficient approaches such as running similar profiled programs concurrently nor did they addressed the potential risk of resource constraint despite the need to draw resources shared by Energex. EMCa also noted that Ergon Energy had primarily used desktop analysis instead of visual inspection and verification to identify where to prioritise its projects and did not appear to conduct field testing or specific asset assessments.[106]

We do not consider relying heavily on desktop analysis to be prudent approach as it may overstate the sites that need to be addressed. Supporting the analysis with physical inspections would provide more credibility to its modelling. As in our decision for the current regulatory control period, we do not have confidence that the desktop analysis represents an accurate calculation of backup protection shortfalls.[107]

Without these considerations, we are unable to accept Ergon Energy's proposed protection projects as efficient or prudent and have adjusted the total capex based on the information available.

Insufficient options analysis

We consider Ergon Energy's proposed $28.2 million for its grid communications projects is not adequately justified. Ergon Energy has not provided credible justification for its preferred options which were limited to:

- Do nothing – base case counterfactual
- Do everything – alternate solution
- Optimised charge – the targeted program.

For the first two options, Ergon Energy did not provide NPV values but opted to incorporate the values in its Grid Comms GT NPV model. EMCa noted that further NPV analysis and consideration of the benefits could have added credibility to the options presented.[108] The further lack of information regarding the input assumptions, such as failure rates, meant that we were unable to understand what contributed to the NPV values provided. We consider there is not enough information to support Ergon Energy's grid control projects in total based on the lack of information on the contributing inputs to Ergon Energy's options analysis. For

105 EMCa, *Review of Ergon 2025/26 to 2029/30 Regulatory Proposal*, September 2024, p. 144.

106 EMCa, *Review of Ergon 2025/26 to 2029/30 Regulatory Proposal*, September 2024, p. 144.

107 AER, *Final decision - Ergon distribution determination 2020–25 - Attachment 5 - Capital expenditure*, June 2020. pp. 13-14.

108 EMCa, *Review of Ergon 2025/26 to 2029/30 Regulatory Proposal*, September 2024, p. 144.

these reasons we have not included $28.2 million of Ergon Energy's grid communications projects.

Deliverability concerns

We have proposed an alternative estimate for Ergon Energy's DC and Bus overcurrent protection duplication projects as the timeframe of certain projects raises deliverability concerns. Ergon Energy has already cited resource constraints in its current regulatory period, and in the absence of evidence to prove otherwise, we expect this to continue to the next regulatory period. This will significantly impact projects near the end of the forecast regulatory period and we have adjusted our approved capex accordingly.

Backup reach protection improvement program

Ergon Energy submitted that it needs to install new protection systems components to detect network faults to comply with clause S5.1.9(f) of the NER, which cite specific fault clearing times. Ergon Energy states that having no backup protection during a fault current would damage upstream plants and result in a breach. However, we found that Ergon Energy's business case did not clearly demonstrate how the installed assets would contribute to its compliance with clause S5.1.9(f) of the NER.

We consider that this project misinterprets the clause and should not apply to low voltage circuits. Investments to address fault clearance times for low voltage circuits is not a sustainable practice and would result in short life assets with significant depreciation costs.

Without strong supporting evidence to demonstrate the need for the new components, we do not accept Ergon Energy's proposed total of $11.1 million for this program.

B.3 Connections

B.3.1 AER's draft decision

We are satisfied that Ergon Energy's net connections capex forecast of $321.2 million and capital contributions (type 1) of $63.2 million would form part of a total capex forecast that reasonably reflects the capex criteria.[109] We have included these amounts in our substitute estimate of total capex.

B.3.2 Ergon Energy's proposal

Ergon Energy proposed $321.2 million for net connections capex for the 2025–2030 period. This is in line with the actual/estimate expenditure in the current period ($321.1 million). Ergon Energy also proposed $63.2 million in SCS cash capital contributions (type 1).

Ergon Energy's connections forecast is based on an econometric forecast modelling approach for residential and commercial connections.[110] Ergon Energy engaged FTI Consulting to support its modelling approach.

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[109] Contributions from customers can be via direct funding (Type 1 contributions) or in contributed or gifted assets (Type 2 contributions). Only Type 1 capital contribution has been considered in making this decision.

[110] Ergon Energy, *Regulatory Proposal 2025–2030*, January 2024, pp 111-115.

Ergon Energy's econometric model factors in historical trends, demographic forecasts, expected growth in commercial activities, and the relationship between population growth and historic connection volumes in developing its forecasts for connection volumes and unit rates. Specifically, the econometric model considers:[111]

- a linear population growth rate using birth rates, mortality rates,[112] and net migration rates data[113]
- a regression analysis approach to establish a relationship between historic household growth and gross residential connections using data from 2009 to 2021
- a historical relationship between connection volumes and connection expenditure across residential and commercial & industrial customers[114]
- expected price point index (PPI) and wage point index (WPI) escalations in the 2025-30 period.

B.3.3 Reasons for decision

We have taken a holistic approach in assessing Ergon Energy's connections forecast against the capex criteria, including:

- trend analysis of Ergon Energy's past connections expenditure; and
- a bottom-up assessment of Ergon Energy's forecasting methodology and underlying assumptions.

We have also had regard to its information request responses and stakeholder submissions.

B.3.3.1 Trend Analysis

Ergon Energy's historical net connection trend has informed our overall position on connections capex. We are broadly satisfied that Ergon Energy's forecast is likely reasonable as it reflects the historical net connection expenditure. Figure B.8 shows the historical actual/estimate and forecast trend of Ergon Energy's net connections expenditure between 2015–16 to 2029–30.

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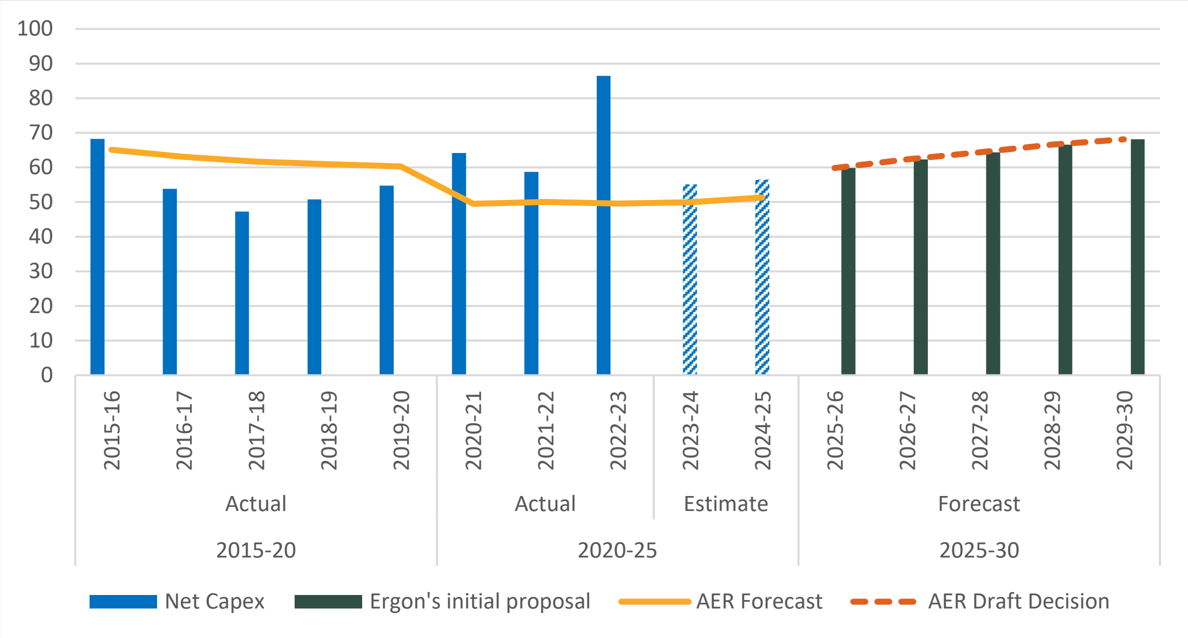
111 FTI Consulting, *Energy Queensland – connections volume and Connex forecasts for 2025–30*, 15 November 2023, pp 20-37.

112 FTI apply ABS birth rates and mortality rates to estimate the number of births and deaths over the period from 2016–2021.

113 The overseas migration rate is calculated using 2021 census survey question where individuals lived 5 years ago. The interstate migrate rate is calculated by comparing different between modelled population and actual population in year 2021.

114 The model uses an Ordinary Least Squares (OLS) regression to establish a relationship between residential and commercial customers.

Figure B.8 Ergon Energy's historical and forecast net connections capex ($ million, $2024–25)



Source: Ergon Energy's proposal and AER analysis

Ergon Energy's actual net connection expenditure is relatively stable over the years, but it incurred a 47% increase in the 2022–23 period compared to the 2021–22 period. While the 2022–23 level is an outlier, Ergon Energy expects a gradual increase in the forecast period.

Ergon Energy's higher expenditure in the 2022–23 period is attributed to a backlog of new connections due to the higher migration rates to regional Queensland post Covid-19.[115] Similarly, Ergon Energy submitted that the gradual increase in the forecast period is due to the higher migration rates and increased development supporting the 2032 Olympic and Paralympic Games.[116] It has supported the increased expenditure using independent data from the Australian Construction Industry Forum. We also had regard to Queensland Government data, which broadly supports the increase in population. Based on this we inferred that the gradual increase in connection volumes is likely reasonable. Therefore, we are satisfied that Ergon Energy's proposal for the forecast period is prudent and efficient.

In addition, we had regard to Ergon Energy's unit rates. We found that Ergon Energy's average unit rate for SCS connections in the forecast period is approximately 7% lower than the current period. This finding supports the CPP30's submission noting that the increasing volume forecasts may improve connection efficiency and lower the unit rate of connections.[117]

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115 Ergon Energy, *Response to information request 015, Question 1*, May 2024.

116 Ergon Energy, *Response to information request 015, Question 2-3*, May 2024.

117 CCP30, *Advice to the AER regarding the Energex and Ergon Energy regulatory proposals 2025–30*, May 2024, pp 20,23,25.

We also reviewed the capital contributions formula. Ergon Energy's capital contributions methodology is consistent with the current period and there are no material changes to the capital contributions policy.

On the evidence above, we are satisfied that that both net connections and capital contributions forecasts are reasonable.[118] Therefore, we have included Ergon Energy's forecast amounts in our substitute estimate of total capex.

B.3.3.2 Bottom-Up Analysis

While Ergon Energy's updated connections capex passed our top-down assessment, we have concerns regarding the application of its econometric model to forecast connections.

We acknowledge Ergon Energy has considered our findings in the 2020–25 regulatory decision. In Ergon Energy's 2020–25 distribution draft determination, we noted that Ergon Energy did not provide evidence supporting its customer connection volumes.[119] Therefore, in response Ergon Energy has developed an econometric model providing evidence to forecast connections.[120]

We have examined Ergon Energy's econometric model and its underlying assumptions in developing connection volume and unit rate. To do this, we first assessed whether the modelling inputs were derived using publicly available data where possible and intermediary calculation steps were transparent.[121] Then, we assessed whether Ergon Energy's methodology for calculating the volume and the unit rate for each category in its model was prudent and efficient. We also had regard to whether it had undertaken sufficient scrutiny in validating its model.

We have a number of concerns with Ergon Energy's econometric model approach, including:

- linear extrapolation of population and connection volumes rather than using a dynamic rate approach adapted by Queensland Government Statistics Office (QGSO)
- lack of transparency and inconsistency in use of modelling parameters, such as adjusting ratio between simple and complex commercial connections without explanation
- indexation of unit rates using PPI and WPI parameters
- inconsistency between its econometric model forecast and the expenditure stated in its 2025–30 regulatory proposal or the SCS capex model.

We have undertaken a sensitivity analysis to consider the impacts of Ergon Energy's modelling approach noted above. Our analysis indicates that our adjustments to the listed

118 We note that we are accepting Ergon Energy's connections forecast in our draft decision. But we have concern with its forecast model.

119 Ergon Energy, *2025–30 Regulatory Proposal,* January 2024, pp 111; AER, *Ergon Energy distribution determination 2020–25: Draft decision – Attachment 5: Capital Expenditure*, October 2019, pp 5-28 – 5-30.

120 Ergon Energy, *2025–30 Regulatory Proposal*, January 2024, pp 111; AER, *Ergon Energy distribution determination 2020–25: Draft decision – Attachment 5: Capital Expenditure*, October 2019, pp 5-28 – 5-30.

121 For instance, we compared Ergon Energy's population growth model with Queensland Government Statistics Office (QGSO) forecasts.

parameters has both positive and negative impacts to the forecasted volumes and unit rates. We consider that a suitable connections forecast model may:

- use a dynamic population growth rate such as the publicly available QGSO data, which would accurately calculate connection volumes and response to the varying growth profile over the period
- use parameters that do not require post modelling adjustments to ensure the model is transparent and can be easily reconciled if any parameters are changed
- use fixed unit rates rather than including WPI and PPI inflators as the escalations are provided for in the SCS capex model across all projects consistently
- act as an input to the SCS capex model as the figure presented in the connections model does not align with the capex model.

While we are satisfied with Ergon Energy's proposed connections capex, we do not accept its modelling approach. Despite requesting further information clarifying Ergon Energy's modelling approach, we were unable to rely on its econometric model in making our decision for forecast connections capex. This is because the net connections capex presented in Ergon Energy's proposal is not consistent with its econometric model. Therefore, we have formed our view on the prudency and efficiency of Ergon Energy's forecast connections capex based on the trend analysis discussed in B.3.3.1.

B.4 ICT

B.4.1 AER's draft decision

We do not accept that Ergon Energy's ICT capex forecast of $258.8 million would form part of a total capex forecast that reasonably reflects the capex criteria. Our draft decision includes $208.7 million in our substitute estimate of total capex, which is $50.1 million (19.4%) lower than Ergon Energy's proposal.

B.4.2 Ergon Energy's proposal

Energy Queensland provides shared business and non-network ICT services to both Ergon Energy and Energex. For its 2025–30 forecast, Energy Queensland developed a combined non-network ICT program and allocated expenditure to each DNSP via its Cost Allocation Method.

Ergon Energy proposed $288.3 million for its total ICT program, which includes $29.4 million in ICT cyber security capex. In this section, we have only assessed the $258.8 million in non-cyber security ICT capex. We assessed ICT cyber security capex separately.

Ergon Energy submitted that the reduction in forecast capex from the 2020–25 period is due to the completion of its non-recurrent major ICT transformation and that its forecast ICT totex per user is returning to previous benchmark levels.[122]

Ergon Energy expects to overspend by $203.4 million (103.4%) in the 2020–25 period. It submitted that the main driver for the overspend in the 2020–25 period was due to

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122 Ergon Energy, *Att. 5.8.01 – Non-network ICT Plan*, January 2024, p. 20.

challenges it faced delivering its major ICT transformation.[123] While some of these challenges were out of Ergon Energy's control, it noted that it underestimated the complexities of a large-scale transformation.[124]

Ergon Energy's combined non-network ICT program includes 7 major investment programs and a minor works program. This includes $29.4 million for its ICT cyber security investment program. Our assessment from here only refers to the 6 non-cyber capex investments of the ICT program, unless otherwise stated. Table B.7 shows Ergon Energy's proposed capex forecast at a program level.

Table B.7 Ergon Energy non-network ICT capex forecast ($ million, $2024–25)

Program	Capex
Customer	55.9
Integrated grid planning	16.1
Asset and works management	30.3
Digital core	39.1
Data & Intelligence	26.2
Digital foundations	71.2
Minor works	20.2
Total	**258.8**

Source: Ergon Energy's proposal

B.4.3 Reasons for decision

We have reviewed the information Ergon Energy provided in support of its ICT capex forecast, including the business cases and cost-benefit models. Where required, we have sought further information from Ergon Energy through information requests.

While Ergon Energy's forecast for the 2025–30 period is lower than actual/estimated ICT capex in the 2020–25 period, we have placed less weight on this observation when viewed in the context of its 2020–25 period overspend of $203.4 million and its decision to exclude it from the RAB. As table B.8 shows, Ergon Energy's forecast for the 2025–30 period is still $91.6 million higher than our final decision for the 2020–25 period.

Table B.8 Ergon energy's ICT capex forecast compared with the AER allowance and actual/estimated capex for the 2020–25 period ($ million, $2024–25)

AER forecast 2020–25	Actual/estimate 2020–25	Overspend	2025–30 forecast
197.6	400.1	203.4	288.3

Source: Ergon Energy's proposal
Note: For a like-for-like comparison, this table includes ICT cyber security capex.

[123] Ergon Energy, *Att. 5.3.11 – Capex ex post justification – Non-network ICT*, January 2024, p. 2.

[124] Ergon Energy, *Att. 5.3.11 – Capex ex post justification – Non-network ICT*, January 2024, p. 14.

While Ergon Energy proposed a decrease in its non-recurrent capex, it proposed an increase in recurrent capex. Ergon Energy submitted that learnings from its major ICT transformation resulted in a change in its approach to ICT business cases for the 2025–30 period.[125] It stated that dealing with the transformation and consolidation of legacy applications becomes exponentially more challenging the longer it is left.[126] Its new approach, termed 'Evergreening', plans for more frequent recurrent upgrades to applications and technologies.

All major investment business cases comprise recurrent and non-recurrent expenditure. We have therefore relied on our bottom-up assessment of the individual major investments to test whether Ergon Energy's recurrent and non-recurrent expenditure is prudent and efficient.

B.4.3.1 Bottom up review of major investments

We do not consider Ergon Energy has provided sufficient information to justify that its ICT capex forecast reasonably reflects the capex criteria. In particular, the major investment business cases do not provide adequate evidence to support its preferred options.

The 6 major investment business cases all present 3 options with the following themes consistent across each business case.[127] Ergon Energy preferred option is option 2 for all 6 business cases.

- Option 1 – Base case. Maintain business capabilities with only minor improvements in efficiency outcomes
- Option 2 – Builds on and enhances the base case by adapting and scaling it to keep pace with the expected industry transition
- Option 3 – Builds on option 1 and 2 by developing capabilities in advance of the industry transition.

We found systemic issues across all six of Ergon Energy's major investment business cases. These include:

- *Preferring options with the lower ranked NPVs* - Ergon Energy preferred option 2 for all 6 major investments despite 3 of the cost benefit analyses showing the lower cost option 1 had the highest ranked NPV. Ergon Energy noted in its business cases that option 3 was discounted due to the higher cost without realising higher benefits (than option 2). However, it does not use the same logic when preferring option 2 over option 1 under the same circumstances. We consider Ergon Energy's inconsistent approach to options analysis is likely biasing higher cost options.
- *No quantified benefits or quantified benefits with little detail* - Some of the business cases describe qualitative benefits but do not quantify them. The qualitative benefits lack detail and do not explain any qualitative risks such as compliance or loss of vendor support. We asked Ergon Energy to provide further information on any risk costs associated with its major investment initiatives. For example, where Ergon Energy proposed version upgrades to its ICT systems, we would expect it to detail the risks

125 Ergon Energy, *Att. 5.8.01 - Non-network ICT Plan*, January 2024, p. 7.

126 Ergon Energy, *Att. 5.8.01 - Non-network ICT Plan*, January 2024, p. 7.

127 Ergon Energy, *Att. 5.8.01 - Non-network ICT Plan*, January 2024, p. 27.

(qualitative or quantitative) associated with not undertaking the upgrades to show there is an identified need. Ergon Energy did not provide greater detail and instead referred to the high-level qualitative risks in its business cases.[128]

- *Insufficient detail on the costs* - The cost initiatives in the NPV models are too high level to understand the scope of works. Where cost initiatives lacked detail, we asked Ergon Energy to provide further information on the scope of works.[129] In response, Ergon Energy did not provide further detail and instead pointed to the same descriptions in the models that we noted lacked detail.[130] We consider there is insufficient detail in Ergon Energy's major investment business cases to determine the efficiency of costs.

We encourage Ergon Energy to address these concerns in its revised proposal.

We also had regard to stakeholder comments about Ergon Energy's ICT program. The RRG noted it has concerns about Ergon Energy's ICT governance process given its 2020–25 period major transformation was allowed to continue to 2023 despite significant cost overruns. It is unsure of Ergon Energy's ability to deliver its proposed 2025–30 suite of projects on time and on budget. [131]

CCP30 highlighted that its forecast is still higher than the AER's 2020–25 forecast and noted its concerns about Ergon Energy's ability to continue to manage large ICT projects given its experience in the 2020–25 period. [132] It also recommended that the AER consider how its major ICT transformation has benefited customers.

We encourage Ergon Energy to engage with its stakeholders on the concerns raised and how it intends to address the AER's concerns in its revised proposal.

In its ICT plan, Ergon Energy noted the following: [133]

> The Option 1 - Base Case (Keep the Lights On) is the ongoing requirement that a prudent and efficient DNSP would do to achieve the NER capex and opex objectives in 2030, based on ongoing predictable conservative growth.

Given our findings, we consider this 'maintain' option to be more appropriate and therefore include an alternative forecast of $208.7 million that is associated with Ergon Energy's option 1 for all 6 major investments.[134]

Ergon Energy noted there are interdependencies between its proposed cyber security option and its non-cyber ICT major investments.[135] Given Ergon Energy has not provided sufficient

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128 Ergon Energy, *Response to information request 018 - Non-network ICT capex response*, May 2024, p. 4.

129 Ergon Energy, *Response to information request 018 - Non-network ICT capex response,* May 2024.

130 Ergon Energy, *Response to information request 018 - Non-network ICT capex response,* May 2024.

131 RRG, *Submission on Ergon and Energex electricity distribution regulatory proposals 2025–30 and the Australian Energy Regulator's Issues Paper*, May 2024, p. 25.

132 CCP30, *Advice to the AER regarding the Energex and Ergon Energy regulatory proposals 2025–30*, May 2024, p. 19.

133 Ergon Energy, *Att. 5.8.01 – Non-network ICT Plan*, January 2024, p. 27.

134 This does not include $29.4 million for ICT cyber security, which we assessed separately.

135 Ergon Energy, *Att. 5.8.04 – Business Case Cyber Security*, January 2024, p. 26.

detail on the scope of works in its non-cyber NPV models, it is not clear to what extent option 1 would allow (or not allow) for the full deliverability of its proposed cyber security program.

B.5 Resilience

B.5.1 AER's draft decision

We do not accept that Ergon Energy's resilience capex forecast of $53.1 million would form part of a total capex forecast that reasonably reflects the capex criteria. We have included $26.8 million capex for resilience in our alternative estimate of total capex, which is $26.2 million (49.4%) lower than Ergon Energy's proposal.

B.5.2 Ergon Energy's proposal

Ergon Energy proposed $53.1 million for resilience capex, comprised of the following programs:

- Bushfire and Flood Program ($16.1 million)[136] - This program relates to a range of network solutions to address heightened risk of bushfire and floods. These solutions include pole wrapping and covered conductor in high bushfire risk areas as well as asset relocations and additional switching points in high flood risk areas.
- Mobile Substations Program ($8.8 million)[137] - This program relates to additional mobile substation support during unplanned outages to meet its safety net targets. These mobile substations are 10MVA units with HV and LV switchgear mounted on a trailer.
- Mobile Generation Program ($19.3 million)[138] - This program relates to additional mobile generators and associated plant to increase capabilities of its network to further support planned and unplanned works, hot-weather events, contingency planning and disaster recovery response.
- SAPS Program ($8.8 million)[139] - This program proposes 10 Stand-Alone Power Systems trial sites in the 2025–2030 regulatory control period to assess the capability of a SAPS to allow for the retirement of a portion of Ergon Energy's single wire earth return (SWER) network.

B.5.3 Reasons for the decision

We have reviewed the information Ergon Energy provided in support of its resilience capex forecast, including the business cases and information requests responses.

Based on the information before us, we consider that there is insufficient evidence to support Ergon Energy's total forecast for resilience-related expenditure. We have accepted some expenditure where we could see merit in the program even though the justification for the

136 Ergon Energy, *Att. 5.5.10 – Business Case Bushfire and Flood,* January 2024, p. 4.

137 Ergon Energy, *Ergon NOMAD BC v1.0 - confidential*, September 2024, p. 4.

138 Ergon Energy, *Att. 5.5.10 – Business Case New Mobile Generation,* January 2024, p. 6.

139 Ergon Energy, *Stand-Alone Power System (SAPS) Technical Specification – confidential*, November 2023.

expenditure was not entirely solid. We acknowledge that resilience is a still an emerging area of expenditure where forecasting is challenging.

In coming to our position, we note that Ergon Energy has not provided the evidence expected to support resilience-related funding as noted in the AER's network resilience guidance note.[140] As noted in our guidance note, the AER expects NSPs to demonstrate, within reason, that:

- there is a causal relationship between the proposed resilience expenditure and the expected increase in the extreme weather events
- the proposed expenditure is required to maintain service levels and is based on the option that likely achieves the greatest net benefit of the feasible options considered
- consumers have been fully informed of different resilience expenditure options, including the implications stemming from these options, and that they are supportive of the proposed expenditure.

On the first point, we note that Ergon Energy provide information in its business cases which sets out some of the current difficulties Ergon Energy faces with the impact from extreme weather events. Ergon Energy also provided some information about the general future climate in the Queensland region referring to the Bureau of Meteorology's State of the Climate 2022 report, and the IPCC's Sixth Assessment Report.

However, we were not provided with sufficient quantitative evidence of a causal linkage between the likelihood of future extreme weather events on the Ergon Energy network and the likely impact that it has on Ergon Energy's assets, in terms of likelihood of the consequences and cost of consequences on the network. As noted in the guidance note, we would also expect evidence of how its proposed resilience-related expenditure will limit the cost of damage from extreme weather events and why ex-ante expenditure is more efficient than ex-post expenditure.[141]

On the second point above, we expect proposals for resilience-related expenditure to demonstrate there is or likely to be an increase in network risk, the benefit of the resilience-related funding (for instance, further avoiding or reducing the frequency or duration of outages) outweighs the costs of the investment, and the preferred funding option provides more net benefit against other feasible options.[142] We note that Ergon Energy provided some business cases to show the net benefit of its investment. But the prudency and efficiency of that investment was not established, as there was no evidence of causal linkage between the likelihood of the future extreme weather event on the Ergon Energy network and the likely impact of the network (and therefore how the investment would address this impact).

On the third point above, we also expect businesses to engage with its consumers on how its ex-ante funding proposal will ensure any risk to manage extreme weather events are allocated efficiently between consumers and businesses. Also, businesses should provide evidence that it worked collaboratively with affected communities and other responsible entities to understand the communities' genuine needs to plan and prepare for, as well as

140 AER, *Network Resilience a note on key issues*, April 2022, p. 11.

141 AER, *Network Resilience a note on key issues*, April 2022, p. 11.

142 AER, *Network Resilience a note on key issues*, April 2022, p. 12.

recover from a natural disaster. We also expect businesses to consult with the wider consumer base on their preferences for bearing resilience-related costs to address localised impacts.[143]

We encourage Ergon Energy to include this evidence as part of its revised proposal on resilience.

We discuss our specific findings on the proposed programs below.

Bushfire and Flood Program

We have accepted forecast capex associated with Ergon Energy's bushfire and flood program. We note that Ergon Energy has assessed the parts of the network likely to be impacted through its analysis of its high-risk feeders.[144]

While there are areas for improvement in Ergon Energy's economic justification for this program, we see merit in the proposed solutions and the level of expenditure reasonable for the type of risks it is proposing to mitigate. We had regard to the similarity of these solutions to those we accepted in our decision on Endeavour Energy's resilience proposal for the 2024–29 regulatory control period.[145]

Mobile Substations

We have accepted forecast capex associated with the Mobile substation program, noting that the primary driver for this program is the compliance of Ergon Energy's Distribution Authority condition rather than resilience.[146] While there might be is a resilience element to this program, Ergon Energy has not sufficiently described or provided evidence to support this program on this basis. We also observed a negative net benefit from Ergon Energy's submitted business case.

Under its Distribution Authority conditions[147], Ergon Energy has safety net targets in which it must restore supply following an N-1 event (a credible outage on an element of the network). As a baseline target, Ergon Energy must fully restore supply within 24 hours in regional areas and within 48 hours for rural areas.

We observe that Ergon Energy has limited network redundancy options when it comes to complying with its safety net requirement. Its network comprises of numerous single transformer substations. In the event of a transformer failure in a single transformer substation, there is little network redundancy other than existing load transfers which tends to be limited in a rural network. Thus, the recovery time without mobile substation support will be the best repair/replace time of a transformer which is typically more than 24 hours. We

143 AER, Network *Resilience a note on key issues*, April 2022, pp. 12-13.

144 Ergon Energy, *5.5.14 – Business Case New Mobile Generation – January 2024 - public*, January 2024, p. 24.

145 AER, *AER – Draft Decision Attachment 5 – Capital expenditure – Endeavour Energy – 2024–29 Distribution revenue proposal*, October 2019, pp. 15-18.

146 Ergon Energy, *Ergon Energy NOMAD Construction and Deployment Business Case,* September 2024, p. 5.

147 Department of Energy and Public Works, *Distribution Authority No. D01/99 issued to Ergon Energy Corporation Limited*, Schedule 4 – Service Safety Net Targets, p. 20.

therefore consider its reasonable for Ergon Energy to address its safety net targets through this program, and that there may also be resilience-related benefits from this program.

Mobile Generation

Due to similarities between this program and the mobile substation program, we sought further information on the differences and interactions between these programs.

Ergon Energy noted the following in its response to our information request:[148]

- Mobile substation is focused on supporting zone substations during power outages impacting thousands of customers, as mobile generator is more a distribution feeder focused solution
- Mobile generators are used for localised events in HV and LV networks, and typically secure supply to a few hundred customers.

Ergon Energy further noted the main justifications for mobile generation are to address distribution feeder planned outages and meet minimum service standard (MSS) performance.[149] Its mobile generation problem statement identifies the lack of timely support across the network to both planned works and unplanned outages. Within this, there are two main related legislative compliances, its MSS and its safety net targets.

To determine whether additional mobile substations are required, we assessed the relationship between Ergon Energy unplanned and planned outages with capex (Figure B.9 below). We found that planned outage duration is increasing in the past 5 years at a much higher rate compared to unplanned outages. This is likely caused by the increase in asset constructions over these years.

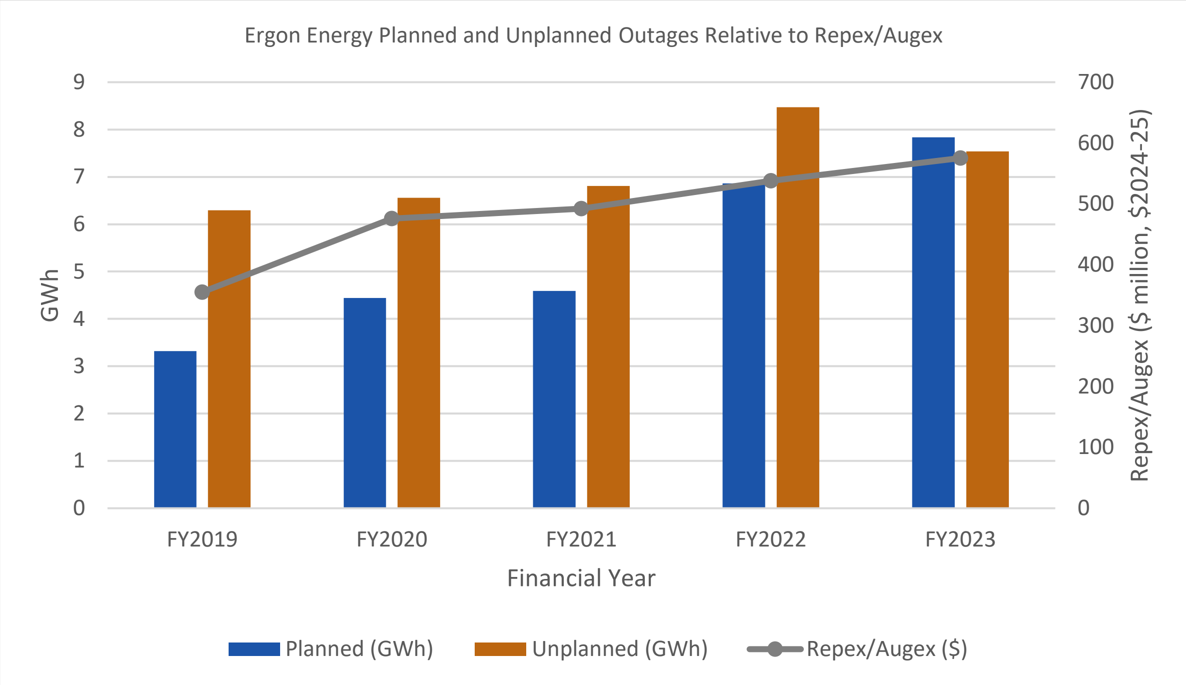
We consider that the high level of planned outages as seen in FY2022 and FY2023 would have restricted Ergon Energy's ability to recover from unplanned outages. This is because a larger portion of the network is out of service and switched at an abnormal state for construction purposes which leaves the networks less prepared for unplanned outages.

Given our draft decision capex forecast brings Ergon Energy's annual capex back down to between the FY2019 & FY2020 level, we consider that the additional mobile generation is not required to meet its MSS target in the 2025–30 period.

148 Ergon Energy, *Response to information request 046 - Ergon Augex*, June 2024, p. 2.

149 Ergon Energy, *Response to information request 046 - Ergon Augex*, June 2024, p. 2.

Figure B.9 Ergon Energy Planned and Unplanned Outages Relative to Repex/Augex ($ million, $2024–25)



Source: AER analysis

As with its mobile substation program, the primary driver for this program appears to be compliance with Ergon Energy's Distribution Authority conditions, rather than resilience. While we acknowledge that resilience may be an outcome from the deployment of mobile generators, Ergon Energy did not provide sufficient information for us to assess this program from that perspective.

Therefore, given the lack of information, we have included 10% of the proposed capex based on its historical deployment of mobile generators for planned and unplanned outages at a ratio of 9:1 (ratio of planned to unplanned outages).[150] We encourage Ergon Energy to provide further information including a root cause analysis for its higher planned and unplanned outages in recent years as well as the flow-on impacts of its replacement programs in its revised proposal.

SAPS Program

We have not accepted forecast capex associated with the Stand-Alone Power Systems (SAPS) program. The program aims to replace fringe of grid supply to select customers using SAPS as an alternative electricity supply.

Ergon Energy noted that the Queensland Government has not yet "opted-in" to the SAPS Framework.[151] As a result, Ergon Energy's proposal might not see the retirement of overhead lines in the 2025–30 period. The application of the SAPS Framework is required for it to be

150 Ergon Energy, *Att. 5.5.14 – Business Case New Mobile Generation,* January 2024, p. 15.

151 Ergon Energy, *Response to information request 046 - Ergon Augex,* June 2024, p. 4.

considered a regulated network asset and customers to be supplied via a SAPS as equivalent to poles and wires supply.

While there is a resilience element in the deployment of SAPS, we note that the Queensland Government's current position to not opt into the SAPS Framework means that the primary consumer benefit from SAPS deployment will not be realised; this being, removing the need for long overhead lines to remote communities. Without this key benefit, the business case to implement SAPS is unlikely to be net positive on the additional reliability and resilience benefits alone.

We support the implementation of SAPS where we consider, based on the information and evidence available, that there are positive net benefits for consumers. As this does not appear to be the case, we consider the capex for the SAPS program is not prudent and efficient.

B.6 CER integration

B.6.1 AER's draft decision

We accept that Ergon Energy's capex forecast of $63.0 million to integrate consumer energy resources (CER) reasonably reflects the capex criteria, and have included this amount in our alternative estimate of total capex.

B.6.2 Ergon Energy's proposal

Ergon Energy proposed the following activities in its DER integration strategy:[152]

- The continued implementation of dynamic operating envelopes and its Low Voltage Distributed Energy Resource Management System
- Establishing visibility on transformers exhibiting high export penetration, installing low voltage monitors to measure power quality, and expanding the telemetry hub
- Increasing hosting capacity to establish a basic export level of 1.5kW per customer
- Investments in network protection systems.[153]

In addition to its proposed investments, Ergon Energy plans to implement demand management measures through two-way pricing (export tariffs) and "solar soak" hot water and other load control capability.

In its business case, Ergon Energy presented its base case scenario as a counterfactual where it is required to upgrade distribution transformers as they reach capacity. This results in a present value cost of $605 million over a 25-year forecast period, and provides the basis for the majority of the estimated customer benefits (that is, the proposed investments will avoid these future costs). However, Ergon Energy did not demonstrate that its base case scenario, in which customers are able to export 100% of their capacity, represents the current level of export service experienced by its customers.

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152 DER refers to distributed energy resources. We use the term consumer energy resources (CER), noting that these resources are largely owned or leased by residential or small business customers.

153 Ergon Energy, *Att. 5.6.01 - DER Integration Strategy*, January 2024.

Ergon Energy's business case considered a range of potential investments, and found that the implementation of dynamic connections provides the highest NPV. However, it argued that this option alone does not offer choice to customers that want to export their full capacity. Ergon Energy assumed that 50% of customers will choose a dynamic connection and receive between 1.5kW and 10kW of export capacity (per phase), whereas the remaining 50% of customers will pay export tariffs and (generally) maintain an export capacity of 5kW. Therefore, Ergon Energy assumed that 10% of the expenditure associated with its counterfactual scenario will be necessary to increase hosting capacity and ensure that the basic export limit is maintained at 1.5kW.

Ergon Energy also proposed an opex step change to acquire near real time smart meter data, which it claimed is necessary to implement advanced dynamic connections, which provide greater benefits than basic dynamic connections. However, the primary benefits of the proposed opex step change relate to safety and reliability and are quantified in a separate business case. We discuss our assessment of this opex step change in Attachment 6.

B.6.3 Reasons for the decision

We reviewed Ergon Energy's DER integration strategy as well as its supporting NPV analysis, which it provided in response to our information request. We also considered stakeholder submissions on Ergon Energy's proposal. Our assessment was informed by both our CER strategy and DER integration expenditure guidance note.[154,155] Key to our assessment was understanding whether Ergon Energy reasonably estimated customer benefits in its NPV analysis. We also considered stakeholder submissions on Ergon Energy's proposal.

Estimation of benefits

Ergon Energy estimated the following types of benefits:

- Avoided network investment. As noted above, these represent the majority of customer benefits and are overstated because Ergon Energy assumed that customers currently experience zero export curtailment. In reality, the benefits associated with avoided network investment are likely to be far lower.
- Avoided export curtailment. To value these benefits, Ergon Energy applied the AER's customer export curtailment values to average yearly 30-minute load curves from a selection of its most representative feeders. We consider these benefits were estimated reasonably.
- Reductions in carbon emissions. We found that Ergon Energy applied appropriate emissions intensity factors, as forecast by AEMO. However, it significantly underestimated these benefits by applying a lower carbon value than the interim values of emissions reduction, which were published after it submitted its revenue proposal.[156] Ergon Energy assumed a starting carbon value of $35 per tonne and increased it by $1

154 AER, *Consumer energy resources strategy*, April 2023.

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

156 AER, *Valuing emissions reduction – AER guidance and explanatory statement*, May 2024.

each year over the modelling period. This is much lower than the published interim values of emissions reduction, which start at $75 in 2025 and reach over $300 in 2045.

Stakeholder submissions

Most stakeholder submissions commented on the proposed export tariffs and the basic export level, rather than the nature of Ergon Energy's proposed investments. Origin Energy noted that a significant proportion of customers are likely to exceed the basic export limit and incur additional costs.[157] Other stakeholders expressed dissatisfaction with the proposed level of spending on CER integration, with some suggesting that Ergon Energy should be forecasting greater levels of capex to help accelerate the energy transition.[158]

Conclusion

We consider that Ergon Energy's capex forecast reasonably reflects the capex criteria because:

- its overall strategy is sound, and maximising existing capacity by prioritising dynamic connection investments over increasing hosting capacity is prudent
- emissions reduction benefits will be much greater than Ergon Energy quantified, which supports the case for the proposed investments
- greater network visibility is necessary so that Ergon Energy can better identify export constraints and existing service levels and prioritise its investments
- stakeholders supported Ergon Energy undertaking more investments to integrate CER in its network.

We consider that Ergon Energy's NPV analysis is flawed as it overstates the level of "business as usual" investment needed to maintain the export service, absent its proposed investments. This has the effect of overstating avoided network investment benefits.

B.7 Fleet

B.7.1 AER's draft decision

We do not accept that Ergon Energy's fleet capex forecast of $243.0 million would form part of a total capex forecast that reasonably reflects the capex criteria. We have included $210.1 million capex for fleet in our alternative estimate of total capex, which is $32.9 million (13.6%) lower than Ergon Energy's proposal.

B.7.2 Ergon Energy's proposal

Ergon Energy proposed $243 million for fleet capex with $21.4 million of associated disposals. Ergon Energy's total fleet capex is $72.3 million (42.4%) higher than the current period spend of $170.7 million. It submitted that the uplift in expenditure across periods is driven by the following:[159]

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157 Origin Energy, Submission – 2025-30 Electricity Determination – Energex, Ergon & SA Power Networks, May 2024.

158 Master Electricians Australia, Submission – 2025-30 Electricity Determination – Energex, May 2024.

159 Ergon Energy, *Att. 5.9.06 – Non-network Fleet Plan 2025–30*, January 2024, p. 5.

- Higher unit rates - Ergon Energy forecast significant increases in unit rates across major fleet vehicle categories such as heavy commercial vehicles HCVs (52%), crane borers (36%) and elevated work platforms (EWP) (23%).[160]

- Addressing shortfalls in 2020–25 period fleet replacements - A review of a longer historical series shows that the first three years of Ergon Energy's 2020–25 period fleet expenditure is below that of the preceding period. It cites supply constraints as the main driver behind this decrease. As a result, it highlighted the requirement for heightened spending to address this shortfall in the final two years of the 2020–25 period, continuing into the 2025–30 period.[161]

- Full Time Equivalent (FTE) uplift - Ergon Energy proposed fleet capex to support programmes of work resulting from a wider uplift to other capex categories. Its proposed uplift is $20.0 million.

- Changes to the replacement strategy for elevated work platforms (EWP) (>14m) and crane borers - Ergon Energy is proposing to reduce and align the rebuild rates for EWPs and crane borers.[162] This will result in the earlier replacement of more vehicles, incurring greater cost than the base case.

B.7.3 Reasons for the decision

We have reviewed the information Ergon Energy provided in support of its fleet capex forecast, including the business cases, cost-benefit models and information requests responses.

Ergon Energy has not satisfied us that the proposed program for fleet is prudent and efficient. While we consider that some uplift in fleet expenditure is reasonable, Ergon Energy has not satisfied us that its total forecast is reasonable. Our alternative forecast is based on our assessment of Ergon Energy's fleet program, discussed below.

Higher unit rates

Ergon Energy undertook a review of unit rates in preparing its fleet forecast. It observed a significant increase in unit rates over the current regulatory control period.[163]

We performed benchmarking analysis of Ergon Energy's proposed increased unit rates, relative to the recent decisions of other DNSPs. We found the forecast falls within an acceptable range. We therefore consider an uplift in fleet expenditure in the 2025–30 period to be reasonable.

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160 Ergon Energy, *Att. 5.9.06 – Non-network Fleet Plan 2025–30*, January 2024, p.20.

161 Ergon Energy, *Att. 5.9.06 – Non-network Fleet Plan 2025–30*, January 2024, p.21.

162 Currently, most EWPs are rebuilt at 10 years to extend their service lives to 15 years (90% for Energex, 70% for Ergon Energy). The remaining 10% and 30%, for Energex and Ergon respectively, are replaced as new at 10 years. For crane borers, 97% are rebuilt at 10 years to extend their service lives to 20 years across both networks.

163 Ergon Energy, *Att. 5.9.06 – Non-network Fleet Plan 2025–30*, January 2024, p. 20.

Addressing shortfalls in 2020–25 period fleet replacements

We consider the justification for heightened fleet volume requirements resulting from 2020–25 period supply shortages reasonable. This supports the case for an uplift in fleet capex, relative to the 2020–25 period.

However, the majority of Ergon Energy's fleet proposal did not have supporting cost benefit analysis (CBA) models.[164] In particular, it did not provide sufficient evidence to explain how its preferred investment has been tested against other options to demonstrate prudency and efficiency of its forecast, especially for the largest components of its fleet program. As such, we do not consider that Ergon Energy has justified the magnitude of the uplift that it has proposed. Below, we review programs contained within the fleet capex proposal that we have not included in our alternative forecast.

Changes to the replacement strategy

Ergon Energy has not substantiated the benefits of its proposed changes to the replacement strategy for EWPs and crane borers.[165] It stated the benefits of the program are due to reductions in unscheduled downtime for younger assets, relative to older assets.[166] Ergon Energy provided an estimate of an average avoided days out of service per asset.[167] However, it provided no evidence or modelling in support of these figures. As this forms the basis of the benefits calculated in the NPV model, we do not consider that Ergon Energy's conclusion that its preferred option has the lowest negative NPV is justified. We encourage Ergon Energy to address our concerns in its revised proposal.

FTE uplift

We issued an information request on the increased employee numbers resulting from the uplift in the wider capex proposal. Ergon Energy provided a model that demonstrated that additional employees cause an increase to the fleet capex forecast (and the converse is also true).[168] As a result of reductions to other areas of capex, we have reduced the FTE uplift driven fleet expenditure accordingly.

To derive our alternative forecast, we have we removed the changes to the replacement strategies ($12.9 million) and the FTE uplift ($20 million) from the fleet capex forecast. The removal of the FTE uplift was calculated using the model that Ergon Energy provided (described above) and is based upon the wider reductions to the total network capex forecast. We have accepted the remainder of Ergon Energy's proposal. We consider that our alternative forecast accounts for an appropriate uplift in fleet expenditure to address the supply issues of the current period, described above. This uplift also accounts for increased unit rates and volumes.

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164 Ergon Energy, *Response to Information Request 006*, April 2024, p. 2.

165 Currently, 70% of EWPs are rebuilt at 10 years to extend their service lives to 15 years. The remaining 30% are replaced as new at 10 years. For crane borers, 97% are rebuilt at 10 years to extend their service lives to 20 years across both networks.

166 Ergon Energy, *Att. 5.9.07A – Business Case Non-Network Fleet – EWP Replacement*, January 2024, p. 11.

167 Ergon Energy, *Att. 5.9.07A – Business Case Non-Network Fleet – EWP Replacement*, January 2024, p. 11.

168 Ergon Energy, *Response to Information Request 049*, June 2024, p. 1.

B.8 Property

B.8.1 AER's draft decision

We do not accept that Ergon Energy's property capex forecast of $174.7 million would form part of a total capex forecast that reasonably reflects the capex criteria. Our draft decision includes $170.7 million in property capex, which is a $4.0 million (or 2.3%) lower than Ergon Energy Energy's proposal.

B.8.2 Ergon Energy's proposal

Ergon Energy proposed a property capex forecast of $174.7 million, which represents 3.1% of total forecast capex. This includes capitalised leases of $17.2 million, which is a new category for the 2025–30 period.[169] Excluding capitalised leases, Ergon Energy's proposal is $157.4 million in property capex, which is 10.9% higher than its actuals/estimates for the 2020–25 period.

Ergon Energy submitted that the key drivers for the uplift in property capex are several major one-off projects to address capacity constraints and condition-based assessments.[170]

B.8.3 Reasons for the decision

When assessing Ergon Energy's proposal for property capex, we had regard to major project business cases, cost-benefit models, and further supporting information provided by Ergon Energy. The RRG noted that it supports an AER focus on areas of capex with a proposed material increase from Ergon Energy's actuals/estimates in the 2020–25 period (including property).[171]

Ergon Energy submitted that its general property programs (minor, base, residence and security) forecasts are based on historical expenditure.[172] Ergon Energy provided its historical expenditure for these programs and demonstrated that it used an average of its most recent 8 years of actual expenditure to calculate its 2025–30 forecast.[173] Our analysis shows that its forecast for this program is 24% lower than its most recent 5 years of actual expenditure and approximately in line with our final decision for the 2020–25 period. On this basis, we are satisfied that that Ergon Energy's forecasts are reasonably reflective of the efficient costs of a prudent operator.

In addition to the general property programs, Ergon Energy proposed four major projects for the 2025–30 period. From our bottom-up review of Ergon Energy's major property project business cases we consider that, aside from the Townsville training facility redevelopment, its investments are prudent and efficient. Ergon Energy assessed investment options against appropriate business-as-usual counterfactuals. We consider the business cases sufficiently

169 Leases that were previously treated as opex are now capitalised due to a change in accounting standards.

170 Ergon Energy, *Att. 5.9.01 - Non-network capex Property Plan 2025–30*, January 2024, p. 33.

171 RRG, *Submission on Ergon Energy and Energex electricity distribution regulatory proposals 2025–30 and the Australian Energy Regulator's Issues Paper*, May 2024, p. 4

172 Ergon Energy, *Att. 5.9.01 - Non-network capex Property Plan 2025–30*, January 2024, p 27.

173 Ergon Energy, *Response to information request 005*, April 2024.

describe the need for investment with reasonable assumptions based on historical data and industry standards.

Townsville training facility redevelopment

We consider Ergon Energy has not justified the Townsville training facility redevelopment. It submitted that the proposed redevelopment was driven by poor building condition and forecast capacity constraints for internal and external training.[174]

Ergon Energy submitted that its preferred redevelopment option would fulfill the growing demands of the training department (including external training of third parties).[175] Ergon Energy's NPV model included additional training revenue from third parties as benefits for the redevelopment option. Ergon Energy confirmed that this revenue is collected directly from third parties and the training is classified as alternative control services.[176]

We do not consider revenue Ergon Energy collects from third parties benefit the consumers of standard control services. Ergon Energy stated that it considers training third parties benefit the consumers of standard control services as these participants work on its regulated network.[177] It did not provide reasoning as to how consumers benefit nor did it provide any further quantification of these benefits.

While there may be benefits to consumers relating to training third parties that work on Ergon Energy's regulated network, we do not consider the revenue it collects from providing this training is the appropriate quantification. As such, we removed the additional training revenue from Ergon Energy's Townsville NPV model. Once we removed these benefits from the NPV calculations, the preferred option changed to the lower cost business-as-usual base case. We therefore included capex for the base case option, which is $4.0 million lower than Ergon Energy's preferred option for Townsville.

For the base case, we included asset defect rectification capex that Ergon Energy scheduled in financial year 2023–24 as well as any subsequent recurring capex up until financial year 2029–30. Ergon scheduled this rectification work for the 2020–25 regulatory period in its options analysis but did not undertake the work as it considered the redevelopment the most cost-effective option.[178]

B.9 Capitalised overheads

Overhead costs include business support costs not directly incurred in producing output, and shared costs that the business cannot directly allocate to a particular business activity or cost centre. The Australian Accounting Standards and the distributor's cost allocation methodology determine the allocation of overheads.

174 Ergon Energy, *Att. 5.9.05A - Business case Non-network Property - Townsville Training*, January 2024, p 3.

175 Ergon Energy, *Att. 5.9.05A - Business case Non-network Property - Townsville Training*, January 2024, p 17.

176 Ergon Energy, *Response to Information Request 013*, April 2024.

177 Ergon Energy, *Response to Information Request 013*, April 2024.

178 Ergon Energy, *Response to Information Request 013*, April 2024.

B.9.1 AER's draft decision

We do not accept that Ergon Energy's capitalised overhead forecast of $1316.1 million would form part of a total capex forecast that reasonably reflects the capex criteria. Our draft decision includes $874.4 million in capitalised overheads, which is a $441.7 million (or 33.6%) lower than Ergon Energy Energy's proposal.

B.9.2 Ergon Energy's proposal

Ergon Energy proposed $1316.1 million for capitalised overheads for the 2025–30 period. To arrive at its forecast, Ergon Energy used its own methodology based on a bottom-up build.[179]

In addition, Ergon Energy has applied an annual 1% efficiency adjustment to its capitalised overheads forecast.

B.9.3 Reasons for the decision

The AER has a standardised approach to forecasting overheads which has been applied by almost all NSPs. We do not require NSPs to adopt the AER's approach but expect that a different approach is transparent so that it can verified by the AER to ensure reasonableness of assumptions.

We have reviewed Ergon Energy's methodology and do not consider that sufficient evidence has been provided to support the reasonableness of its approach. This is because:

- Its cost pool calculations, from which its overheads are allocated, use hardcoded data with no supporting information. As such, we are unable to verify Ergon Energy's figures;
- For these types of costs, we find that a bottom-up approach tends to overstate a NSP's requirement. Thus, we would expect a top-down check of its capitalised overhead forecast which was not provided; and
- We note a wide disparity between Ergon Energy's forecast overheads and those produced by our standard methodology without supporting evidence to explain the reasons for why Ergon Energy's approach is more appropriate than the AER's approach.

The standard AER methodology is based on:

- 75% of capitalised overheads are fixed.
- 25% of capitalised overheads vary with direct capex.

The forecast for capitalised overheads is calculated by assuming that for every 4% change in direct capex, capitalised overheads change by 1%.

Using our standard approach, an increase in direct capex of the size proposed by Ergon would produce a $50.7 million (5.5%) increase in capitalised overheads, against Ergon Energy's proposed increase of $398 million (43%).

[179] Ergon Energy, *Response to information request 014 - Capitalised Overheads*, May 2024.

We have used our standard methodology including three years of actual expenditure. As Ergon Energy has proposed a 1% productivity adjustment, this has been included in our alternative forecast, although we note that our standard approach does not include that adjustment. We commend Ergon Energy for introducing the 1% productivity adjustment to its capitalised overheads forecast.

Our final decision will update for changes in total direct capex and we will re-test the methodology using the available four years of current period actual expenditure. Ergon Energy's proposal did not explain why it selected to use one year of actual expenditure. We encourage Ergon Energy to provide further information to support its selected number of

Shortened forms

Term	Definition
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulatory
capex	capital expenditure
CCP26	Consumer Challenge Panel, sub-panel 26
CER	customer energy resources
DNSP or distributor	Distribution Network Service Provider
ENA	Energy Networks Australia
EV	electric vehicle
ICT	information and communication technologies
NEL	National Electricity Laws
NEO	National Electricity Objectives
NER	National Electricity Rules
NPV	net present value
NSP	Network Service Provider
opex	operating expenditure
RAB	regulated asset base
repex	replacement expenditure
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SCADA	supervisory control and data acquisition
SCS	standard control service