Final Decision

Ergon Energy Electricity Distribution Determination 2025 to 2030

(1 July 2025 to 30 June 2030)

Attachment 6
Operating expenditure

April 2025

AUSTRALIAN ENERGY REGULATOR

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Amendment record

Version	Date	Pages
1	30 April 2025	30

List of attachments

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

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

The final decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

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Contents

6 Operating expenditure

Operating expenditure (opex) refers to the operating, maintenance and other non-capital expenses incurred in the provision of standard control services. Forecast opex for standard control services (SCS) is one of the building blocks we use to determine a service provider's total revenue requirement.

This attachment outlines our assessment of Ergon Energy's proposed total opex forecast for the 2025–30 regulatory control period (2025–30 period).

6.1 Final decision

Our final decision is to not accept Ergon Energy's total opex forecast of $2,562.9 million ($2024–25),[1] including debt raising costs, for the 2025–30 period.[2] This is primarily driven by us not accepting Ergon Energy's use of 2023–24 as the base year to forecast its revised opex proposal, and our substitution of Ergon Energy's actual 2022–23 opex as the base year for our alternative estimate of total opex.

In our draft decision,[3] which accepted Ergon Energy's initial total opex forecast, we used Ergon Energy's estimated 2023–24 base year opex in our alternative estimate of total opex. However, we noted at the time that we could not determine if 2023–24 was an appropriate choice of base year (i.e. that it was representative of the nature of efficient costs the businesses required into 2025–30 period) until audited actual opex for 2023–24 was reported in Ergon Energy's revised proposal. Further, as Ergon Energy had advised us in the lead up to the draft decision that its actual opex for 2023–24 was going to be significantly higher than the estimate used in its initial proposal, we noted that we would need to re-examine the choice of base year for the final decision, with particular focus on the drivers of the Ergon Energy's increasing opex, and whether 2023–24 or another year, would be most the appropriate base year. We asked Ergon Energy to consider these issues and update its rationale for the choice of base year in the revised proposal.

Ergon Energy maintained in its revised proposal that 2023–24 continued to be the best choice of base year, as it was the most recent year for which audited data was available. Ergon Energy further noted that it did not consider 2022–23 as an appropriate choice of base year, because 'it does not provide a realistic expectation of on-going costs'.[4] Ergon Energy's revised proposal reported actual opex for 2023–24 that was 23.5% higher than the estimate it included in its initial proposal. Ergon Energy also updated the efficiency adjustment it applied in its initial proposal (recognising the higher 2023–24 base opex in its revised proposal was materially inefficient), included transition costs (not included in its initial proposal) to allow it to transition it's operations to this benchmarked efficient level of opex over the next regulatory period, and proposed a new base adjustment to remove one-off emergency response costs related to significant weather events that occurred in 2023–24

1 All dollars referenced in this attachment are on a $2024–25 basis.

2 Ergon Energy, 6.01 – Model – SCS Opex model, November 2024.

3 AER, *Draft Decision, Attachment 6 – Operating expenditure – Ergon Energy – 2025-30 Distribution revenue proposal,* September 2024, pp. 11–14.

4 Ergon Energy, *2025–30 Revised Regulatory Proposal*, November 2024, p. 87.

from its 2023–24 base opex.[5] Together, these changes resulted in Ergon Energy's revised total opex proposal being $183.9 million (7.7%) higher than its initial proposal and our draft decision.

To select a base year that best reflects the prudent and efficient costs Ergon Energy would need to deliver the required services over the next regulatory period, we assessed Ergon Energy's proposed 2023–24 base opex, and alternative recent years for which audited actuals are available, against the opex criteria.[6] We considered the drivers of Ergon Energy's increasing opex, as well as the extent to which a given year was materially inefficient,[7] included one-off costs and was consistent with the revealed costs of the network. We concluded that using 2023–24 as the base year for our alternative estimate of total opex would not be consistent with the opex criteria, including because Ergon Energy's 2023–24 opex is materially inefficient and includes significant one-off costs. We consider that 2022–23 is the most appropriate choice of base year of recent audited actuals, and that it reasonably reflects the prudent and efficient costs Ergon Energy needs to deliver the required services over the next regulatory period.

Given the above, we have used Ergon Energy's actual opex for 2022–23 as the base year for our alternative estimate of total opex for the final decision. As we have not found Ergon Energy's 2022–23 actual opex to be materially inefficient, we have not applied an efficiency adjustment or included transition costs, as proposed by Ergon Energy for its 2023–24 base year. We also did not apply Ergon Energy's proposed base adjustment for its 2023–24 significant weather events, because these were not incurred in 2022–23. We have largely applied other base adjustments and trend consistent with Ergon Energy's revised proposal and our draft decision, with the amounts updated using Ergon Energy's actual expenditure for 2022–23. The differences between Ergon Energy's revised proposal and our alternative estimates for these opex components are largely due to the mechanical update from moving to a 2022–23 base year.

Key differences between our alternative estimate of total opex and Ergon Energy's revised proposal, that are not primarily driven by the change of base year, include that we:

- substituted Ergon Energy's revised maximum demand forecast, which were based on a 'native load' measure that accounted for major embedded generation, with our forecast based on a 'network load' measure, which is not adjusted for major embedded generation capacity. We then applied our standard approach to ratchet the revised maximum demand forecast, reducing the output growth forecast in our alternative estimate by $23.0 million, relative to Ergon Energy's revised proposal.
- did not include the $10.0 million Ergon Energy proposed for the smart meter data step change, as while we agreed that it was prudent for Ergon Energy to upgrade its analytics

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5 Ergon Energy, *6.01 – Model – SCS Opex model,* November 2024.

6 AER, *Final decision, Expenditure Forecast Assessment Guideline – Electricity Distribution*, October 2024, p. 22, states that where actual expenditure in the base year reasonably reflects the opex criteria, we will set base opex equal to actual expenditure for those cost categories forecast using the revealed cost approach. The opex criteria are set out in cl. 6.5.6(c) of the NER.

7 AER, *Better Resets Handbook*, July 2024, p. 24.

and data management capabilities, we considered that this would already be funded through rate of change and reported expenditure already in its 2022–23 base year opex.

Accounting for the above changes, our alternative estimate of total forecast opex is $2,331.1 million. This is materially below ($231.8 million, or 9.0%) Ergon Energy's revised proposal total opex forecast of $2,562.9 million.[8] Our final decision is therefore to substitute our total opex forecast of $2,331.1 million, including debt raising costs, for the 2025–30 period, as reasonably reflecting the opex criteria.[9]

Table 6.1 sets out Ergon Energy's revised opex proposal (based on its proposed 2023–24 base year), our alternative estimate that is the basis for the final decision (based on 2022–23 as the base year), and the difference between our alternative estimate and Ergon Energy's revised proposal.

We discuss the components of our alternative estimate below in section 6.4. Full details of our alternative estimate are set out in our opex model, which is available on our website.

[8] Ergon Energy, *6.01 – Model – SCS Opex model*, November 2024.

[9] The opex criteria are set out in cl. 6.5.6(c) of the NER and the opex factors are set out in cl. 6.5.6(e). We must not accept a distributor's proposed opex if we are not satisfied that it reasonably reflects those criteria: NER, cl. 6.5.6(d).

Table 6.1 Comparison of Ergon Energy's proposal and our final decision ($million, 2024–25)

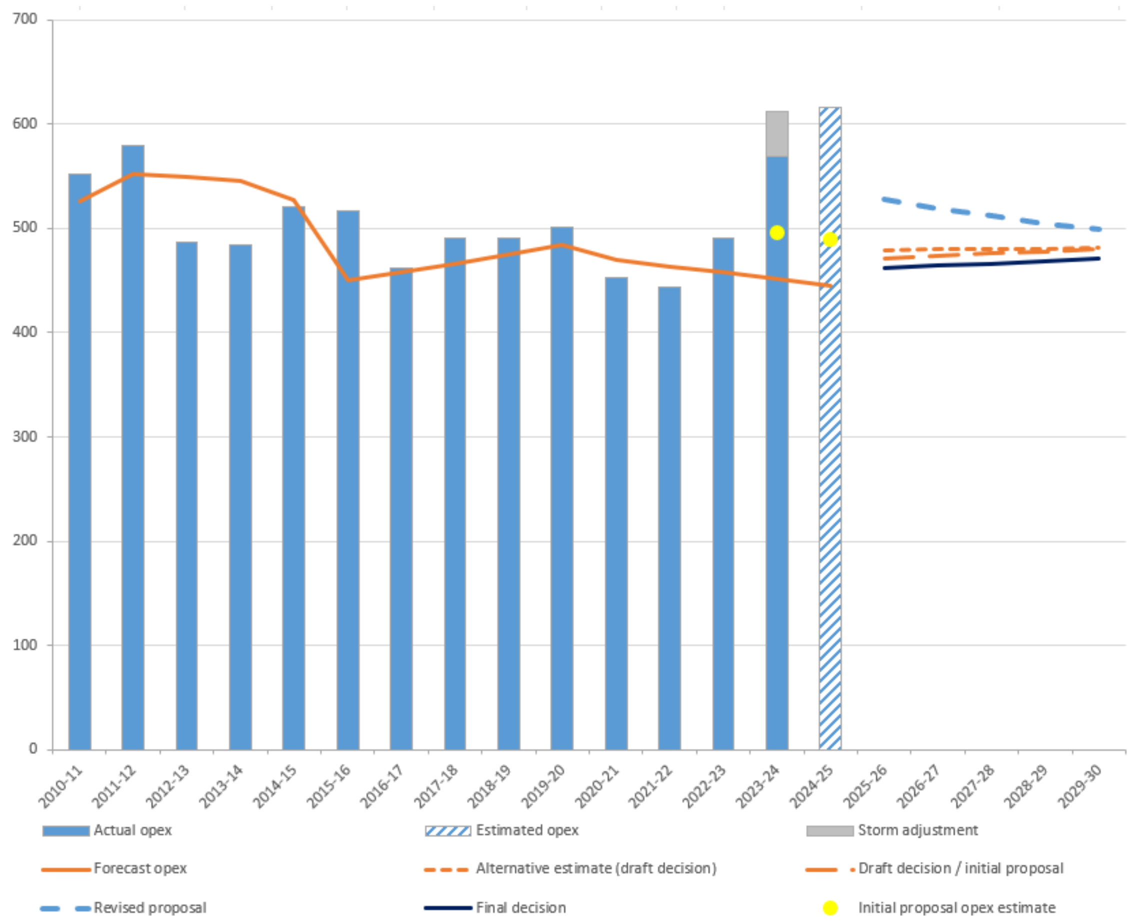
Driver	Ergon Energy proposal / AER draft decision	Ergon Energy revised proposal	AER Final decision	Difference, $million	Difference, %
Reported opex in relevant base year*	**2481.0** *2023–24	**2959.7** *2023–24	**2403.9** *2022–23	**–555.8**	**–21.7%**
Efficiency adjustment	**–55.3**	**–206.5**	**–**	**206.5**	**8.1%**
Transition cost	**–**	**83.1**	**–**	**–83.1**	**–3.2%**
Base adjustment – emergency response storm costs	–	–214.9	–	214.9	8.4%
Base adjustment – ESO levy	–38.5	–33.7	–33.2	0.5	0.0%
Base adjustment – Property leases	–29.5	–25.7	–14.1	11.5	0.4%
Total base year adjustments	**–68.0**	**–274.3**	**–47.3**	**227.0**	**8.9%**
Final year increment	–30.7	–30.5	–61.1	–30.6	**–1.2%**
Remove category specific forecasts	–30.4	–40.2	–38.7	1.5	0.1%
Trend: Output growth	49.4	48.8	25.9	–23.0	–0.9%
Trend: Price growth	51.8	43.6	41.7	–1.9	–0.1%
Trend: Productivity growth	–68.7	–71.9	–33.9	38.0	1.5%
Total trend	**32.5**	**20.5**	**33.7**	**13.2**	**0.5%**
Step change: Smart Meter Data Storage	6.8	10.0	–	–10.0	–0.4%
Total step changes	**6.8**	**10.0**	**–**	**–10.0**	**–0.4%**
Category specific forecasts	–	–	–	–	–
Total opex, excluding debt raising costs	**2336.0**	**2521.8**	**2290.4**	**–231.4**	**–9.0%**
Debt raising costs	43.1	41.1	40.7	–0.4	–0.0%
Total opex, including debt raising costs	**2379.1**	**2562.9**	**2331.1**	**–231.8**	**–9.0%**

Source: Ergon Energy, *6.02 – Model – SCS Opex Model,* January 2024; Ergon Energy, *6.01 – Model – SCS Opex model*, November 2024; AER analysis.

Note: Numbers may not add up to total due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents zero; *Base year is different between the initial and revised proposal (2023–24) vs. AER final decision (2022–23).

Figure 6.1 compares the total opex forecast for Ergon Energy we have included in this final decision for the 2025–30 period (dark blue line), to Ergon Energy's revised total opex proposal (blue dashed line), as well as Ergon Energy's actual and estimated opex in the previous and current regulatory control period (the blue bars). We have also included Ergon Energy's initial proposal, which was also our draft decision for the 2025–30 period (orange long dashed line). The yellow dots show Ergon Energy's initial proposal estimates of its 2023–24 base year opex, and 2024–25 final year opex.

Figure 6.1 Historical and forecast opex ($million, 2024–25)



Source: Ergon Energy, Economic benchmarking – regulatory information notice responses 2010–24; AER, Final decision PTRM 2010–15, May 2010; AER, Final decision PTRM 2015–20, October 2015; AER, Final decision PTRM 2020–25, June 2020; Ergon Energy, 2025–30 Regulatory proposal, November 2024; Ergon Energy, *Response to AER information request IR#076, ;28 January 2025;* AER analysis.

Our final decision total opex forecast is:

- $42.9 million (1.9%) higher than the opex forecast we approved in our final decision for the 2020–25 regulatory control period[10]
- $285.2 million (–10.9%) lower than Ergon Energy's actual (and estimated) opex in the 2020–25 regulatory control period
- $47.9 million (–2.0%) lower than Ergon Energy's initial proposal, which we accepted in our draft decision.

6.2 Ergon Energy's revised proposal

Ergon Energy included total forecast opex of $2,562.9 million in its revised proposal for the 2025–30 period, as set out in Table 6.2. This is $53.4 million (–2.0%) lower than Ergon Energy's actual and estimated opex for the 2020–25 period, and $183.9 million (7.7%) higher than its initial proposal and our draft decision.[11]

Table 6.2 Ergon Energy's proposed opex ($million, 2024–25)

	2025–26	2026–27	2027–28	2028–298	2029–30	Total
Total opex excluding debt raising costs	519.7	510.6	504.4	496.7	490.4	2,521.8
Debt raising costs	7.9	8.1	8.2	8.4	8.6	41.1
Total opex	**527.6**	**518.6**	**512.7**	**505.1**	**498.9**	**2,562.9**

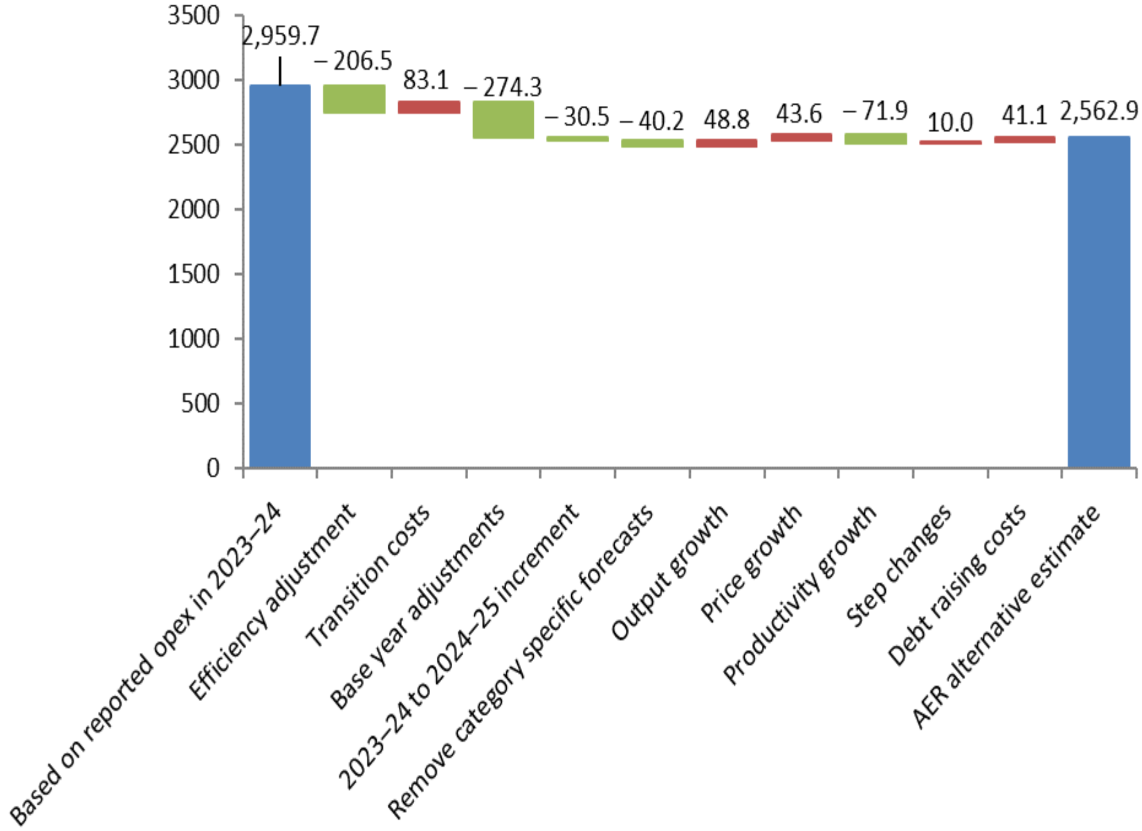
Source: Ergon Energy, *6.01 – Model – SCS Opex model*, November 2024.
Note: Numbers may not add up due to rounding.

In Figure 6.2, we separate Ergon Energy's revised forecast opex proposal into its different components.

10 Difference is calculated based on the opex allowance for the five-year 2020–25 period converted to real 2024–25 dollars using unlagged inflation.

11 Comparisons are inclusive of debt raising costs.

Figure 6.2 Ergon Energy's opex forecast ($million, 2024–25)



Source: Ergon Energy, 6.01 – Model – SCS Opex model, November 2024; AER analysis.
Note: Numbers may not add up to total due to rounding.

Ergon Energy continued to use our standard 'base-step-trend' approach to forecast opex for the 2025–30 period in its revised proposal.

In applying our base-step-trend approach to forecast opex for the 2025–30 period, Ergon Energy:[12]

- used opex in 2023–24 as the base from which to forecast ($2,959.7 million)
- subtracted $206.5 million as an efficiency adjustment
- added $83.1 million for transition costs
- adjusted its total base year forecast opex by subtracting $274.3 million for:
  - Electrical Safety Office levy that will be treated as a jurisdictional scheme in the forecast period ($33.7 million)
  - property lease costs that will be reported as capital expenditure, rather than opex, in the forecast period ($25.7 million)
  - emergency response storm costs, to account for significant weather events during 2023–24 ($214.9 million)

12 Ergon Energy, *6.01 – Model – SCS Opex model*, November 2024.

- subtracted $40.2 million of debt raising costs, to account for the removal of opex categories forecast separately from its base opex
- subtracted an estimate of the difference between the base year opex and the opex it will incur in the final year of the current regulatory period, decreasing opex by $30.5 million
- applied a rate of change comprising of:
  - output growth ($48.8 million)
  - real price growth ($43.6 million)
  - productivity growth of 1.0% per year (–$71.9 million).
- added one step change totalling $10.0 million for Smart meter data
- added $41.1 million of debt raising costs, to arrive at total forecast opex of $2,562.9 million over the 2025–30 period.

6.2.1 Stakeholder views

We received submissions from Energy Queensland's Reset Reference Group (RRG) and the AER Consumer Challenge Panel Sub-Panel (CCP30) that raised issues related to opex.

The RRG submitted that it doubted that Ergon Energy or Energex are likely to meet their revised opex forecasts, largely due to generous terms included in the new Enterprise Bargaining Agreement (EBA), which took effect in June 2024.[13] Further, the RRG noted that:

- Ergon Energy's and Energex's forecast opex in 2024–25 (the final year of the current regulatory period) is significantly higher than the actual 2023–24 base year opex reported in the revised proposal (excluding the one-off storm costs). Given this, the RRG questioned whether the 2023–24 base year is actually representative of Ergon Energy's or Energex's business' costs in 2025–30.[14]
- It is not convinced that the AER's standard approach to giving transition costs when making an efficiency adjustment to base opex should be applied for Ergon Energy or Energex. The RRG asked the AER to require more evidence of transition plans and costs before determining if transition costs are appropriate, and that the allocation of transition costs should be conditional on the businesses achieving efficiencies.[15]

The CCP30 emphasised that there are significant changes in Ergon Energy's and Energex's revised proposal that were not consulted on adequately or transparently, including:[16]

- the significant increase in opex
- how Ergon Energy and Energex will deliver on the 1% productivity growth forecast and efficiency gains needed to achieve the proposed level of opex.

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13 RRG, *Submission on Ergon Energy's revised proposal and draft decision 2025–30*, January 2025, p. 8.

14 RRG, *Submission on Ergon Energy's revised proposal and draft decision 2025–30*, January 2025, pp. 39–40.

15 RRG, *Submission on Ergon Energy's revised proposal and draft decision 2025–30*, January 2025, p. 39.

16 CCP30, *Submission on Ergon Energy's revised proposal and draft decision 2025*–30, January 2025. p. 4.

The CCP30 asked that the AER consider these changes very closely given this lack of consultation, Energy Queensland's past performance in overspending, and the risks in delivering the efficiency savings Ergon Energy has flagged.[17]

The CCP30 also expressed doubt that Ergon Energy or Energex will be able to meet the revised opex forecasts,[18] and stated that transition costs are not warranted unless the businesses have a clear and well-articulated plan to transition to an efficient level of costs in the next regulatory period.[19]

These submissions are discussed further in Section 6.4 below.

6.3 Assessment approach

Under the regulatory framework, a business must include a forecast of total opex that it considers is required to meet or manage expected demand, comply with all applicable regulatory obligations, and to maintain the safety, reliability, quality, and security of its network and contribute to achieving emissions reduction targets (the opex objectives).[20]

Our role is to decide whether to accept a business's total opex forecast. We are to form a view about whether a business's forecast of total opex 'reasonably reflects the opex criteria'.[21] In doing so, we must have regard to the opex factors specified in the National Electricity Rules (NER).[22]

The *Expenditure forecast assessment guideline* (the Guideline), together with an explanatory statement, sets out our assessment approach in detail.[23] While the Guideline provides for greater regulatory predictability, transparency and consistency, it is not mandatory. However, if we make a decision that is not in accordance with the Guideline, we must state the reasons for departing from the Guideline.[24]

Our approach is to assess the business's forecast opex over the regulatory control period at a total level, rather than to assess individual opex projects. To do so, we develop an alternative estimate of total opex using a 'top-down' forecasting method, known as the 'base-step-trend' approach.[25] We compare our alternative estimate with the business's total opex forecast to form a view on the reasonableness of the business's proposal. If we are satisfied the business's forecast reasonably reflects the opex criteria, we accept the

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17 CCP30, *Submission on Ergon Energy's revised proposal and draft decision 2025*–30, January 2025. pp. 4–5.

18 CCP30, *Submission on Ergon Energy's revised proposal and draft decision 2025*–30, January 2025, p. 16.

19 CCP30, *Submission on Ergon Energy's revised proposal and draft decision 2025*–30, January 2025, pp. 28–29.

20 NER, cl. 6.5.6(a).

21 NER, cl. 6.5.6(c).

22 NER, cl. 6.6.6(e).

23 AER, *Final decision, Expenditure Forecast Assessment Guideline – Electricity Distribution*, October 2024; AER, *Explanatory statement – expenditure forecast assessment guideline*, November 2013.

24 NER, cl. 6.2.8(c) (1).

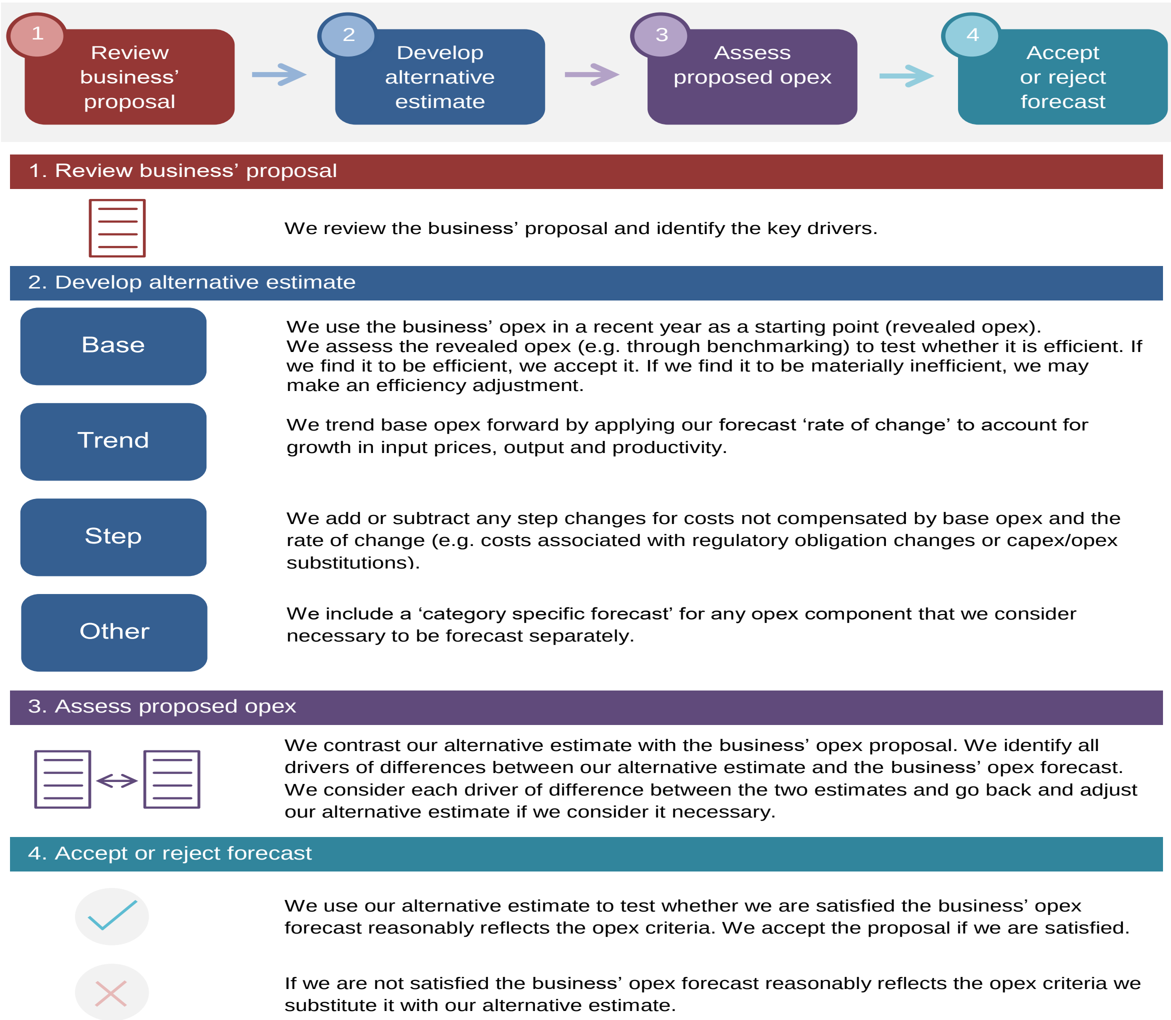
25 A 'top-down' approach forecasts total opex at an aggregate level, rather than forecasting individual projects or categories to build a total opex forecast from the 'bottom up.'

forecast.[26] If we are not satisfied, we substitute the business's forecast with our alternative estimate that we are satisfied reasonably reflects the opex criteria.[27]

In making this decision, we take into account the reasons for the difference between our alternative estimate and the business's proposal, and the materiality of the difference. Further, we take into consideration interrelationships between opex and the other building block components of our decision.[28]

Figure 6.3 summarises the 'base-step-trend' forecasting approach.

Figure 6.3 Our opex assessment approach



6.3.1 Interrelationships

In assessing Ergon Energy's total forecast opex, we also take into account other components of its proposal that could interrelate with our opex decision. The matters we considered in this regard included:

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26 NER, cl. 6.5.6(c).

27 NER, cl. 6A.5.6(d).

28 NEL, s. 16(1)(c).

- the EBSS carryover—the level of opex used as the starting point to forecast opex (the final year of the current regulatory control period should be the same as the level of opex used to forecast the EBSS carryover). This consistency ensures that the business is rewarded (or penalised) for any efficiency gains (or losses) it makes in the final year the same as it would for gains or losses made in other years
- the operation of the EBSS in the 2020–25 period, which provided Ergon Energy an incentive to reduce opex in the base year
- the impact of cost drivers that affect both forecast opex and forecast capital expenditure capex). For instance, forecast labour price growth affects forecast capex and our forecast price growth used to estimate the rate of change in opex
- the approach to assessing the rate of return, to ensure there is consistency between our determination of debt raising costs and the rate of return building block
- the outcomes of Ergon Energy's engagement with consumers and stakeholders in developing its proposal and any feedback we have had.

6.4 Reasons for final decision

Our final decision is to not accept Ergon Energy's total opex forecast of $2,562.9 million, including debt raising costs, for the 2025–30 period.[29] This is primarily driven by us not accepting Ergon Energy's proposed use of its actual 2023–24 opex as the base year to forecast our alternative estimate of total opex (the reasons for which are discussed in section 6.4.1.1).

As we have not found Ergon Energy's 2022–23 actual opex to be materially inefficient, we have not applied an efficiency adjustment or included transition costs, as proposed by Ergon Energy for its proposed 2023–24 base year. We also did not apply Ergon Energy's proposed base adjustment for its 2023–24 significant weather events, as these were not incurred in 2022–23. We have largely applied the other base adjustments and trend consistent with Ergon Energy's revised proposal and our draft decision, with amounts for these components updated based on the 2022–23 base year. The differences between Ergon Energy's revised proposal and our alternative estimates for these opex components, shown in Table 6.1, are largely due to the mechanical update from moving to a 2022–23 base year.

Key differences between our alternative estimate of total opex and Ergon Energy's revised proposal that are not primarily driven by the change of base year include that we:

- substituted Ergon Energy's revised maximum demand forecast, which were based on a 'native load' measure that accounted for major embedded generation, with our forecast based on a 'network load' measure, which is not adjusted for major embedded generation capacity. We then applied our standard approach to ratchet the revised maximum demand forecast, reducing the output growth forecast in our alternative estimate by $23.0 million, relative to Ergon Energy's revised proposal.

[29] Ergon Energy, *6.01 – Model – SCS Opex model*, November 2024.

- did not include an amount for Ergon Energy's revised proposal smart meter data step change, compared to the $10.0 million proposed by Ergon Energy. This is consistent with our draft decision approach.[30]

Accounting for the above changes, our alternative estimate of total forecast opex is $2,331.1 million. This is $231.8 million (–9.0%) lower than Ergon Energy's revised proposal total opex forecast of $2,562.9 million.[31] Our final decision is therefore to substitute total opex forecast of $2,331.1 million, including debt raising costs, for the 2025–30 period, as reasonably reflecting the opex criteria.[32]

The following sections outline the key inputs and assumptions we made in developing our alternative estimate of efficient costs for Ergon Energy, using our base–step–trend approach. Full details of our alternative estimate are set out in our opex model, which is available on our website.

6.4.1 Base opex

This section provides our view on the prudent and efficient level of base opex that we consider Ergon Energy would need for the safe and reliable provision of electricity services over the 2025–30 period.

6.4.1.1 Choice of base year

For the final decision, we have not accepted Ergon Energy's proposed use of 2023–24 as the base year to forecast our alternative estimate of total opex, instead relying on Ergon Energy's actual opex for 2022–23.

In our draft decision,[33] in which we accepted Ergon Energy's initial total opex forecast, we used Ergon Energy's estimated 2023–24 base year opex in our alternative estimate of total opex. However, we noted that we could not determine if 2023–24 was an appropriate choice of base year (i.e. that it was representative of the nature of efficient costs the businesses required into 2025–30 period) until audited actual opex for 2023–24 was reported in Ergon Energy's revised proposal. Further, as Ergon Energy had advised us in the lead up to the draft decision that its actual opex for 2023–24 was going to be significantly higher than the estimate used in its initial proposal, we noted that we would need to re-examine the choice of base year for the final decision, with particular focus on the drivers of the Ergon Energy's increasing costs in the current period, and whether 2023–24 or another year, would be the most appropriate base year. We asked Ergon Energy to consider these issues and update its rationale for choice of base year in the revised proposal.

Ergon Energy maintained in its revised proposal that 2023–24 continues to be the best choice of base year, as it was the most recent year for which audited data was available.

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30 AER, *Draft decision, Attachment 6 – Operating expenditure – Ergon Energy – 2025–23 Distribution revenue proposal*, September 2024, pp. 39–43.

31 Ergon Energy, *6.01 – Model – SCS Opex model*, November 2024.

32 The opex criteria are set out in cl. 6.5.6(c) of the NER and the opex factors are set out in cl. 6.5.6(e). We must not accept a distributor's proposed opex if we are not satisfied that it reasonably reflects those criteria: NER, cl. 6.5.6(d).

33 AER, *Draft Decision, Attachment 6 – Operating expenditure - Ergon Energy – 2025–30 Distribution revenue proposal*, September 2024, pp. 11–14.

Ergon Energy further submitted that it did not consider 2022–23 as an appropriate choice of base year as 'it does not provide a realistic expectation of its on-going costs,' noting that 2022–23 does not include 'the full increase in external contractor costs, general inflationary increases and internal labour costs' it has experienced in 2023–24.[34]

Ergon Energy's actual opex for 2023–24 is 23.5% higher than the estimate it included in its initial proposal. Figure 6.1 shows that Ergon Energy's 2023–24 opex represents a significant and rapid increase in its costs relative to the actual level of opex it incurred in the current and previous regulatory periods, and that its forecast opex in 2024–25, the final year of the current period, is even higher. Ergon Energy provided limited additional information in its revised proposal to explain the drivers of these significant and rapid cost increases, noting that the 'increases are due to both internal factors (including labour costs and full-time equivalent increases) and external factors (including general inflationary pressure, contractor costs and extreme weather events)'.[35]

In terms of the extreme weather event driver, Ergon Energy further noted in its revised proposal that its actual 2023–24 base year opex had been impacted by significant weather events, such as cyclone Jasper in December 2023.[36] Ergon Energy estimated that these events contributed an estimated $41.0 million in one-off emergency response costs to its 2023–24 base year opex (the grey component in Figure 6.1).[37] Ergon Energy proposed to remove these one-off costs from its proposed 2023–24 base year opex for the purposes of forecasting its revised total opex.[38]

Noting that Ergon Energy's 2023–24 opex increased significantly even with the one-off costs removed, we sought additional information from Ergon Energy to understand the reasons for the rapid escalation in its costs. Through responses to information request, meetings with Ergon Energy, and a review of its current and previous enterprise agreement (EAs), we understand that key drivers of the higher-than estimated actual opex in 2023–24, and the further forecast increase in 2024–25, to include:

- significant ongoing and one-off increases in Ergon Energy's internal labour costs, resulting from increases in wage and non-wage costs under Ergon Energy's previous EA (which expired in 2024) and a new EA (which took effect in July 2024, but which included backdated provisions increasing costs in 2023–24)[39]
- significant increases in Ergon Energy's external contractor costs related to provisions in the previous and new EAs
- Queensland Government policy directions, including those related to increases in superannuation benefits and the imposition of new levies.

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34 Ergon Energy, *2025–30 Revised Regulatory Proposal,* November 2024, p. 87.

35 Ergon Energy, *2025–30 Revised Regulatory Proposal,* November 2024, p. 87.

36 Ergon Energy, *2025–30 Revised Regulatory Proposal,* November 2024, p. 87.

37 Ergon Energy's estimate of one-off costs is based on the difference between its actual costs emergency response in 2023-24 compared to its historical five-year average for these costs.

38 Ergon Energy, *2025–30 Revised Regulatory Proposal,* November 2024, p. 87.

39 Fair Work Commission, *Energy Queensland Union Collective Agreement 2024 Electrical power industry*, 2 July 2024.

Commenting on Ergon Energy's increasing costs, RRG noted that in addition to wage increases in the new EA of between 3.0 to 4.5% per annum, Energy Queensland indicated to it that the cumulative average increase in annual wages or salaries, inclusive of all conditions in the new EA and against the baseline Ergon Energy assumed for the EA costings, was approximately 25% across its four-year term, with the cumulative nominal percentage increase for each year of the new EA being: Year 1 – 14%; Year 2 – 18%; Year 3 – 22%; Year 4 – 25%.[40]

Ergon Energy further noted in its revised proposal that, consistent with its initial proposal, it had assessed its actual 2023–24 base year opex using the AER's most recent economic benchmarking models and approaches, and that this indicated that it expected to receive an 16.9% efficiency adjustment to its 2023–24 base year.[41] Ergon Energy noted that the size of the efficiency adjustment decreased to 7.8% if its estimated one-off emergency response significant weather events costs were removed.[42] Consistent with the approach used in our draft decision, and Ergon Energy's revised proposal, we reviewed Ergon Energy's actual 2023–24 opex using our 2024 benchmarking results, and agree with Ergon Energy's findings that its actual 2023–24 opex, both with and without the proposed adjustment for emergency response costs, is materially inefficient and would require an efficiency adjustment to adjust it to an efficient opex.

Under the NER, forecast opex must reasonably reflect the opex criteria.[43] Overall, we aim to select a base year that reasonably reflects the prudent and efficient costs a business needs to deliver the required services over the next regulatory period. Standard criteria we have regard to in doing this include that the base year:

- be a recent year for which audited actual opex is available[44]
- be consistent with the revealed costs of the network, assuming opex is largely recurrent[45]
- does not include significant one-off costs[46]
- is not materially inefficient.[47]

To select the base year for the final decision, we considered the most recent years for which audited actuals were available, including Ergon Energy's proposed 2023–24 base year, as well as 2022–23, the third year of the current regulatory period. We considered the information Ergon Energy provided explaining the drivers of its increasing costs, particularly

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40 RRG, *Submission on Ergon Energy's revised proposal and draft decision 2025–30*, January 2025, p. 36.

41 Ergon Energy, *2025–30 Revised Regulatory Proposal,* January 2024, p. 87.

42 Ergon Energy, *2025–30 Revised Regulatory Proposal,* November 2024, p. 87.

43 AER, *Final decision, Expenditure Forecast Assessment Guideline – Electricity Distribution*, October 2024, p. 22, states that where actual expenditure in the base year reasonably reflects the opex criteria, we will set base opex equal to actual expenditure for those cost categories forecast using the revealed cost approach. The opex criteria are set out in cl. 6.5.6(c) of the NER.

44 AER, *Better Resets Handbook*, July 2024, p. 24.

45 AER, *Final decision*, *Expenditure Forecast Assessment Guideline – Electricity Distribution*, October 2024, p. 5.

46 Or if no such year exists, we may use the non-recurrent efficiency gain mechanism to remove the non-recurrent costs from an available year.

47 AER, *Better Resets Handbook*, July 2024, p. 24.

in its proposed base year of 2023–24. Consistent with the above criteria, we also considered the extent to which a given year could be considered materially inefficient, included one-off costs, and was consistent with Ergon Energy's revealed costs of the network. Having regard to all the above, we consider that using Ergon Energy's actual 2023–24 opex as the base year for our alternative estimate of total opex would not be consistent with the opex criteria. Our reasons for this include that while 2023–24 is the most recent year for which audited actuals are available, Ergon Energy's actual 2023–24 opex:

- is not reflective of Ergon Energy's revealed costs over the current and previous regulatory periods
- includes significant one-off costs, including the emergency response costs Ergon Energy proposes to remove, as well as additional one-off costs associated with its EAs, which would need to be estimated and removed if 2023–24 were to be used as the base year
- is materially inefficient and would require an efficiency adjustment to reduce its actual opex to be consistent with an efficient level of opex.

We are satisfied that Ergon Energy's actual 2022–23 opex is the most appropriate choice of base year of recent audited actuals, and that using it in our alternative estimate of total opex would be consistent with the opex criteria.[48] This is because 2022–23:

- is more reflective of Ergon Energy's revealed costs over the current and previous regulatory periods
- does not include significant one-off costs that would require base year adjustments
- is not materially inefficient and does not require an efficiency adjustment (see Section 6.4.1.2).

We note Ergon Energy's submission that its 2022–23 opex may not 'include the full increase in external contractor costs, general inflationary increases and internal labour costs it has experienced recently' (i.e. from 2023–24 onwards).[49] However, our requirement under the NER is not based on a cost recovery framework, rather it requires us to select a base year that reasonably reflects the *prudent and efficient costs* a business needs to deliver the required services over the next regulatory period. We consider that Ergon Energy's 2022–23 opex meets this requirement, and that the trend escalation we have applied to this base year for this final decision (see Section 6.4.3) provides for the efficient escalation of Ergon Energy's costs over time.

The trend escalation of labour costs is forecast using the average of wage price index (WPI) forecasts provided by Ergon Energy's and our consultants. Wage growth over the current regulatory period is forecast to be slightly positive in real terms (i.e. CPI plus) in the trend we are applying.[50] Ergon Energy has indicated that its wage growth over the current period is in line with the CPI,[51] meaning that the trend we apply overcompensates for Ergon Energy's actual wage cost growth. While the WPI forecasts do not directly take changes in non-wage

48 2024-25 cannot be considered as actual audited opex will not be available in time for the final decision.

49 Ergon Energy, *2025–30 Revised Regulatory* Proposal, November 2024, p. 87

50 AER, *Final decision*, Ergon Energy – 2025–30 Distribution revenue proposal – Opex model, April 2025.

51 AER meeting with Ergon Energy, February 14, 2025.

related labour costs into account, our trend assumes these costs move in line with the WPI (i.e. wages) over time. We consider this is a sound assumption, and that the trend escalation we have applied to Ergon Energy's 2022–23 opex also provides for the efficient escalation of Ergon Energy's non-wage related labour costs.

Having regard to the above, we consider that Ergon Energy's 2022–23 opex reasonably reflects the prudent and efficient costs it will need to deliver the required services over the next regulatory period. As a result, we have used 2022–23 as the base year to forecast our alternative estimate of total opex, which is the basis of this final decision.

6.4.1.2 Efficiency of Ergon Energy's opex

As summarised in section 6.3, and in our Expenditure Forecast Assessment Guideline, our preferred approach for forecasting opex is to use a revealed cost approach. This is because opex is largely recurrent and stable at a total level. Where a distribution business is responsive to the financial incentives under the regulatory framework, the actual level of opex it incurs should provide a good estimate of the efficient costs required for it to operate a safe and reliable network and meet its relevant regulatory obligations. However, we do not assume that the business's revealed opex is efficient. We examine the historical trend in opex and use our top-down benchmarking tools, and other assessment techniques, to test whether the business is operating materially inefficiently over the benchmarking period.

Analysis of revealed costs

Figure 6.1 shows that Ergon Energy's actual opex decreased by $93.3 million (16.1%) in 2012–13 compared to the previous year remaining below our forecast for the remainder of the 2010–15 regulatory period. This sustained reduction in opex resulted in Ergon Energy spending $77.2 million (2.9%) less than our forecast for the 2010–15 regulatory period. Ergon Energy's opex over the 2015–20 period remained relatively stable at this lower level of expenditure, albeit above our forecast for the period, with its total opex for the period exceeding our forecast by $129.4 million (5.5%).

Ergon Energy reported further reductions in its opex over the first two years of the current regulatory period (2020–21 and 2021–22), noting that the key drivers of the lower opex included a reduction in maintenance costs, due to a reduction in work completed during the Coronavirus pandemic, and a decrease in other support costs, including training and redundancy costs.[52] Since then, Ergon Energy's opex has risen by $47.1 million (10.6%) in 2022–23, and by $122.2[53] million (24.9%) in 2023–24. It is forecast to remain at this higher level in 2024–25, the final year of the current regulatory period. Ergon Energy's opex is forecast to exceed our allowance for the 2020–25 period by $328.0 million or 14.3%, as a result of the steep increases in opex observed since 2022–23.

Ergon Energy has acknowledged its increasing costs over the current regulatory period and identified key drivers including flood and storm costs in 2023–24, increasing vegetation management costs resulting from newly negotiated contracts, a general increase in costs driven by the COVID–19 pandemic and an increase in labour and overhead costs associated

52 Ergon Energy, *Response to AER information request IR044,* 19 June 2024, p. 2.

53 This number includes $43.0 million of opex associated with the large 2024 storm event and cost pass through (see Figure 6.1).

with growth in its capital program.[54] We also note that the actual and estimated opex for 2023–24 and 2024–25, respectively, reported in Ergon Energy's revised proposal is significantly higher than the estimates provided in its initial proposal (Figure 6.1). In responses to information requests, meetings with the AER, and a review of Ergon Energy's previous and new enterprise agreement (EAs) we understand the increases in 2023–24 and 2024–25 are driven by a combination of significant increases in internal and external labour costs resulting from increases in wage and non-wage costs under Ergon Energy's previous and current enterprise agreements, and to a lesser extent, Queensland government policy directions including those related to superannuation increases and the imposition of new levies.

The increasing trend in Ergon Energy's opex over the current regulatory period and the forecast overspend relative to our allowance, particularly in 2023–24 and 2024–25, warrants further analysis. This analysis is outlined below.

6.4.1.2.1 Benchmarking the efficiency of Ergon Energy's opex over time

We have used our benchmarking tools and other cost analysis to assess and establish whether Ergon Energy is operating relatively efficiently. Our benchmarking results over the long and short time periods indicate that Ergon Energy has historically been amongst the mid to lower performing distribution network service providers (DNSPs).[55]

Period average econometric opex cost function and productivity index number results

This section presents the results of the 4 econometric opex cost function models that compare the relative opex efficiency of Ergon Energy to other distribution businesses in the National Electricity Market. These efficiency scores do not account for the presence of OEFs.

Econometric opex cost function benchmarking results from the *2024 Annual Benchmarking Report* are presented in Figure 6.4 over the long period, and in Figure 6.5 over the short period. The results indicated that when examined over time, Ergon Energy's opex has been operating somewhat below our 0.75 benchmarking comparison point.

Figure 6.4 shows that over the long period Ergon Energy is ranked 12th out of 13 DNSPs (with an average efficiency score of 0.59), while Figure 6.5 shows that Ergon Energy is ranked 10th over the short period (with an average efficiency score of 0.66). This reflects efficiencies that Ergon Energy has achieved relative to other DNSPs over the more recent years in our full 2006–23 benchmarking period. Our standard approach is to use an efficiency score comparison point of 0.75, rather than 1.0, to recognise data and modelling imperfections of any benchmarking exercise. Where the econometric model-average score is below 0.75, we consider that as evidence that a network has been operating with some inefficiency over the relevant period. We consider this may be the case based on Ergon Energy's efficiency scores.

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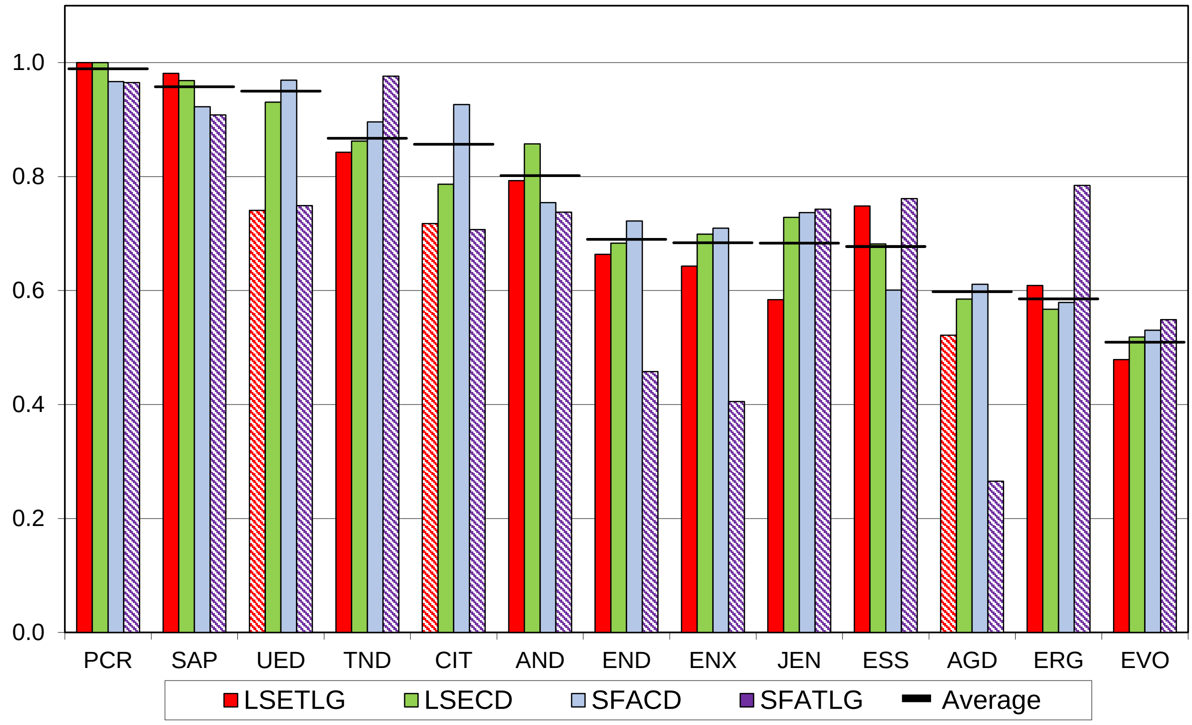
54 Ergon Energy, *Response to AER information request IR#047*, 12 July 2024

55 For information about the use and purpose of economic benchmarking, and details about the techniques we use to benchmark the efficiency of distribution businesses in the National Electricity Market, see AER, *2024 Annual Benchmarking Report – Electricity distribution network service providers*, November 2024.

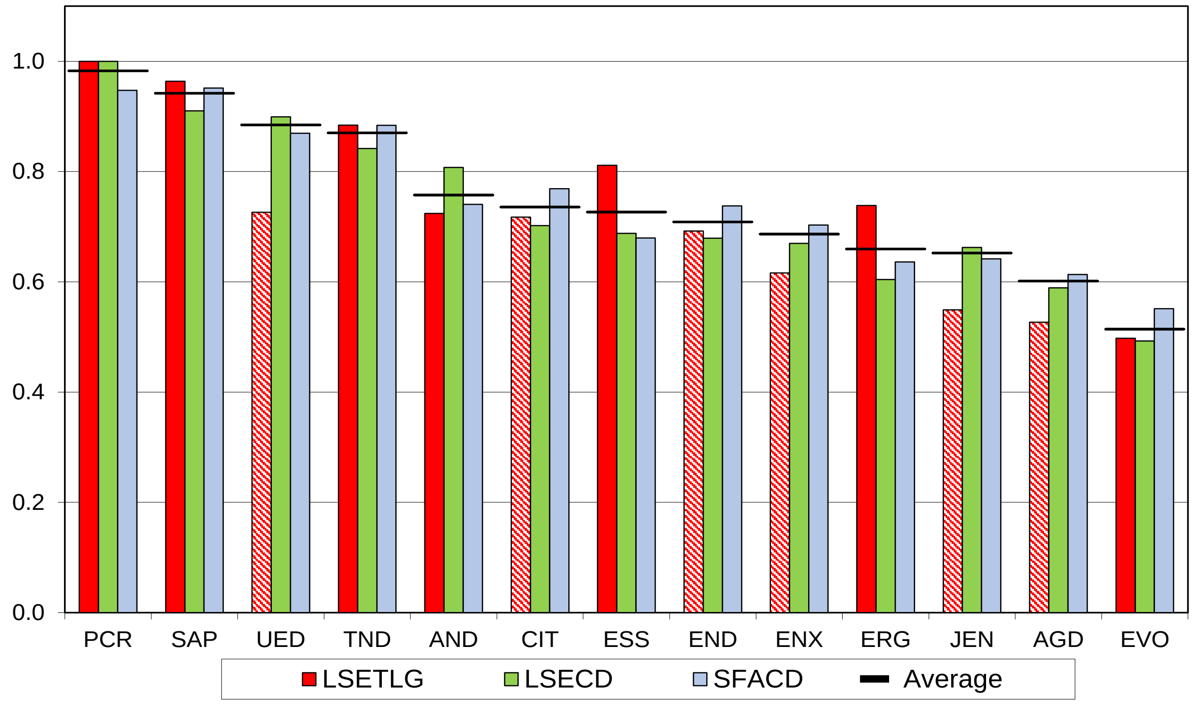
Figure 6.4 Distribution businesses' average opex efficiency scores, 2006–23



Source: AER, *2024 Annual Benchmarking Report – electricity distribution network service providers*, November 2024; AER analysis.

Note: Columns with a hatched pattern represent results that do not satisfy the monotonicity requirement (that an increase in output is only achieved with an increase in opex) and are not included in the model-average efficiency score for each DNSP (which is represented by the black horizontal line).

Figure 6.5 Distribution businesses' average opex efficiency scores, 2012–23



Source: AER, *2024 Annual Benchmarking Report – electricity distribution network service providers*, November 2024; AER analysis.

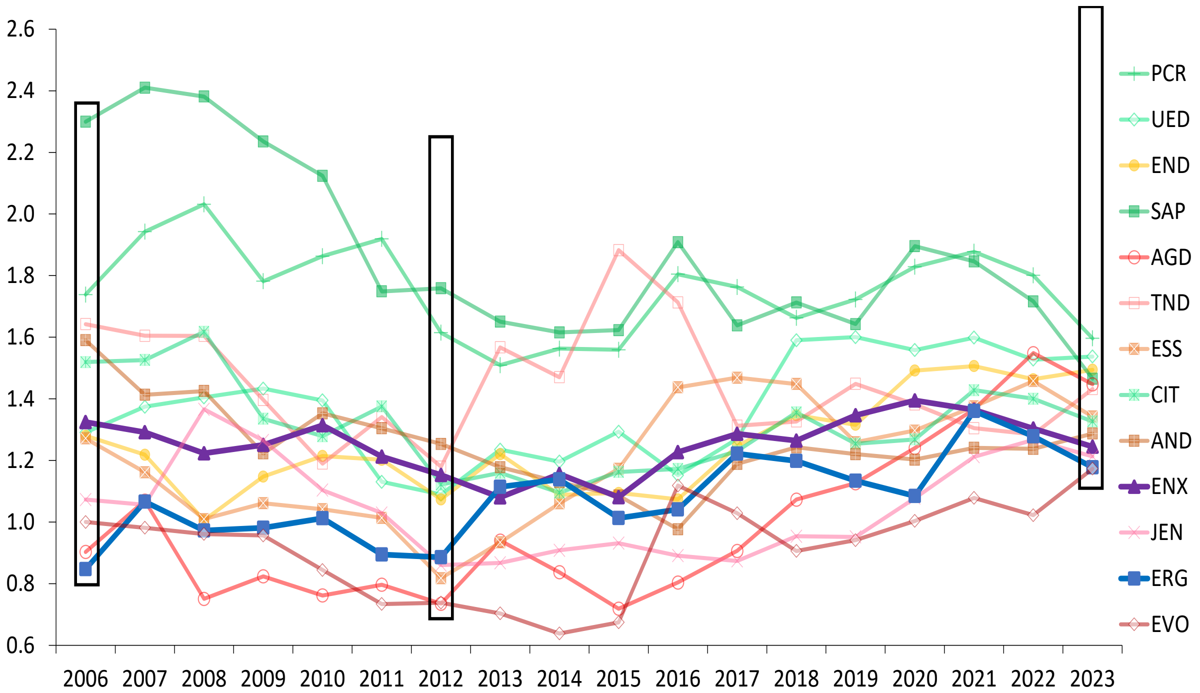
Note: Columns with a hatched pattern represent results that do not satisfy the monotonicity requirement (that an increase in output is only achieved with an increase in opex) and are not included in the model-average efficiency score for each DNSP (which is represented by the black horizontal line).

In addition to the econometric opex cost function models, we also use productivity index number techniques to enable comparisons of productivity levels over time and between DNSPs. The multilateral total factor productivity (MTFP) index measures the total factor productivity of each business over time, whereas the opex and capital multilateral partial factor productivity (MPFP) indexes measure the productivity of opex or capital inputs respectively. Our opex MPFP efficiency results are also not adjusted for material OEFs.

The results from our opex MPFP analysis can be seen in Figure 6.6, where a higher score means that a DNSP is more productivity relative to its peers. These are based on our *2024 Annual Benchmarking Report* results. The opex MPFP results indicate that Ergon Energy's relative performance remained somewhat stable between 2006–12, with its opex MPFP ranking increasing from 13th to 9th by 2012. Its relative performance has exhibited a slight upward trend since 2012, owing mainly to increases in opex MPFP in 2013, 2017 and 2021. These were years in which Ergon Energy reported material reductions in its opex. Ergon Energy achieved an opex MPFP ranking of 6th in 2014; however, its ranking has since decreased to 12th in 2023, as a result of the lowest ranked DNSPs seeing the largest increases in opex MPFP since 2015.

We note that the opex MPFP results are broadly consistent with the econometric opex cost function results.

Figure 6.6 Opex MPFP for individual businesses, 2006–23



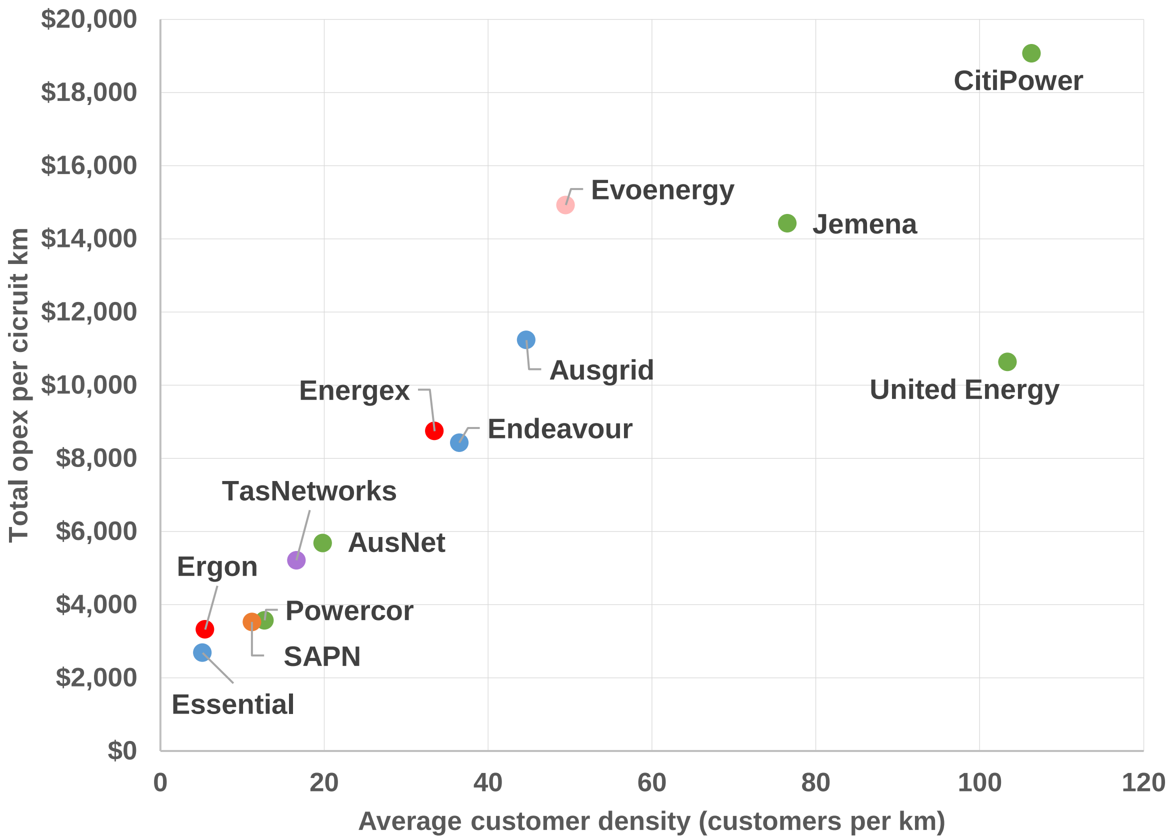
Source: AER, *2024 Annual Benchmarking Report – electricity distribution network service providers*, November 2024; AER analysis.

Partial performance indicators

We have also examined the relative opex performance of Ergon Energy over the 5-year period (2019–23) using partial performance indicators (PPIs). This simple ratio method relates one input to one output. PPIs provide some information about the total and category specific opex performance of a business, and may help as cross-checks and in understanding potential drivers of relative efficiency or inefficiency. Performance on PPIs may be affected by factors outside the control of the DNSP (as for our other benchmarking techniques) and must be analysed with caution, with comparisons also generally limited to businesses with similar characteristics (e.g. customer density).

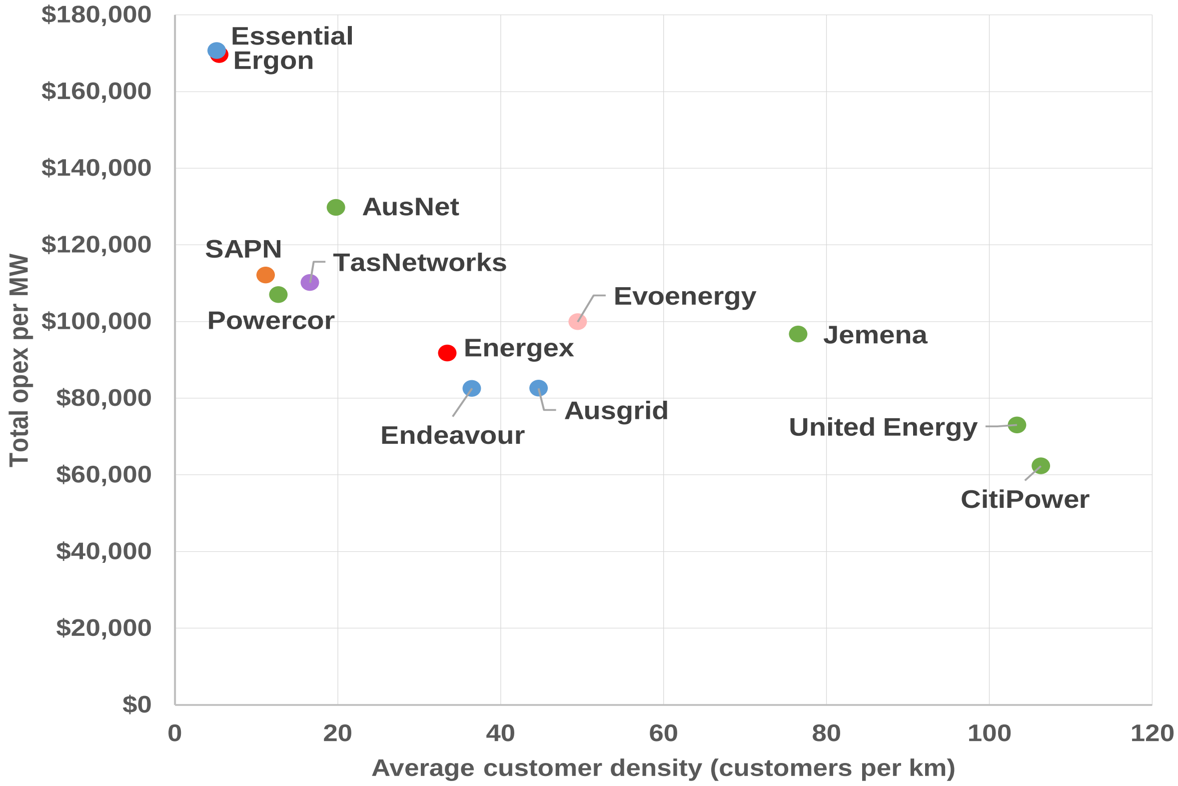
In terms of total opex, both on a per circuit length kilometre and per MW of maximum demand served basis, Ergon Energy benchmarks relatively closely with its most similar comparator on a customer density basis (Essential Energy). This is shown in Figure 6.7 and Figure 6.8 respectively.

Figure 6.7 Total opex per kilometre of circuit length against customer density (2019–23 average)



Source: AER, *2024 Annual Benchmarking Report – electricity distribution network service providers*, November 2024; AER analysis.

Figure 6.8 Total opex per MW of maximum demand against customer density (2019–23 average)



Source: AER, *2024 Annual Benchmarking Report – electricity distribution network service providers*, November 2024; AER analysis.

6.4.1.2.2 Benchmarking the efficiency of Ergon Energy's base year opex

Given the evidence outlined above about the possible inefficiency of Ergon Energy's opex over the 2006–23 period, and the more recent 2012–23 period, we have undertaken further analysis. Consistent with past decisions, this involves the application of our economic benchmarking roll-forward-model, which includes adjusting for OEFs to test the efficiency of the 2022–23 base year opex more directly. We use the results from our econometric opex cost function benchmarking and our benchmarking roll-forward models to derive an estimate of efficient base year opex, and compare this efficiency opex estimate to Ergon Energy's 2022–23 base year opex. We then determine whether there is an efficiency 'gap', and if so, the magnitude of this 'gap'.[56]

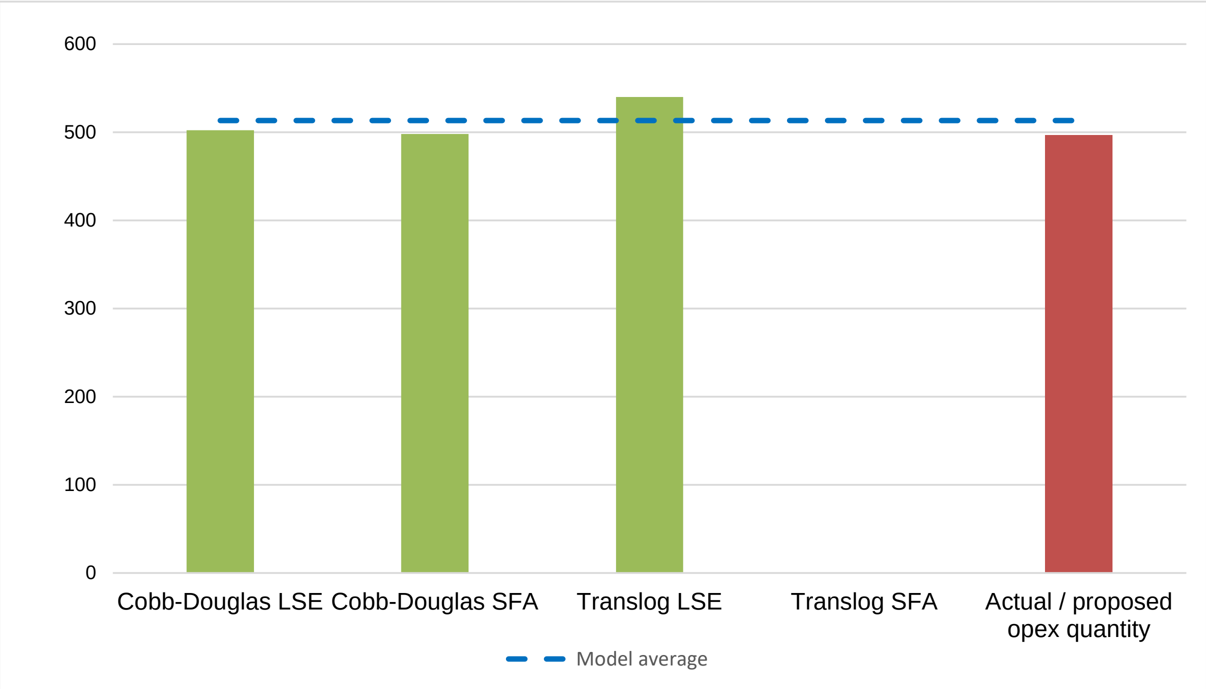
[56] Our final decision applies the same approach as the draft decision in assessing the efficiency of Ergon Energy's base year opex.

We have outlined our approach in further detail in past decisions.[57] We have applied the same OEF adjustments used in our draft decision[58], and subsequently accepted by Ergon Energy.

The results of using our benchmarking roll-forward model (as discussed above) to derive estimated efficient base year opex plus capitalised corporate overheads (blue dashed line) and compare it to base year actual opex plus capitalised corporate overheads (in green) are set out in Figure 6.9 for the long period and Figure 6.10 for the short period.

From these figures, we see that Ergon Energy's 2022–23 base year opex is not materially inefficient, being below our estimated efficient base year opex in both the long and short period measure.

Figure 6.9 Estimates of efficient network services opex using data over the 2006–23 period

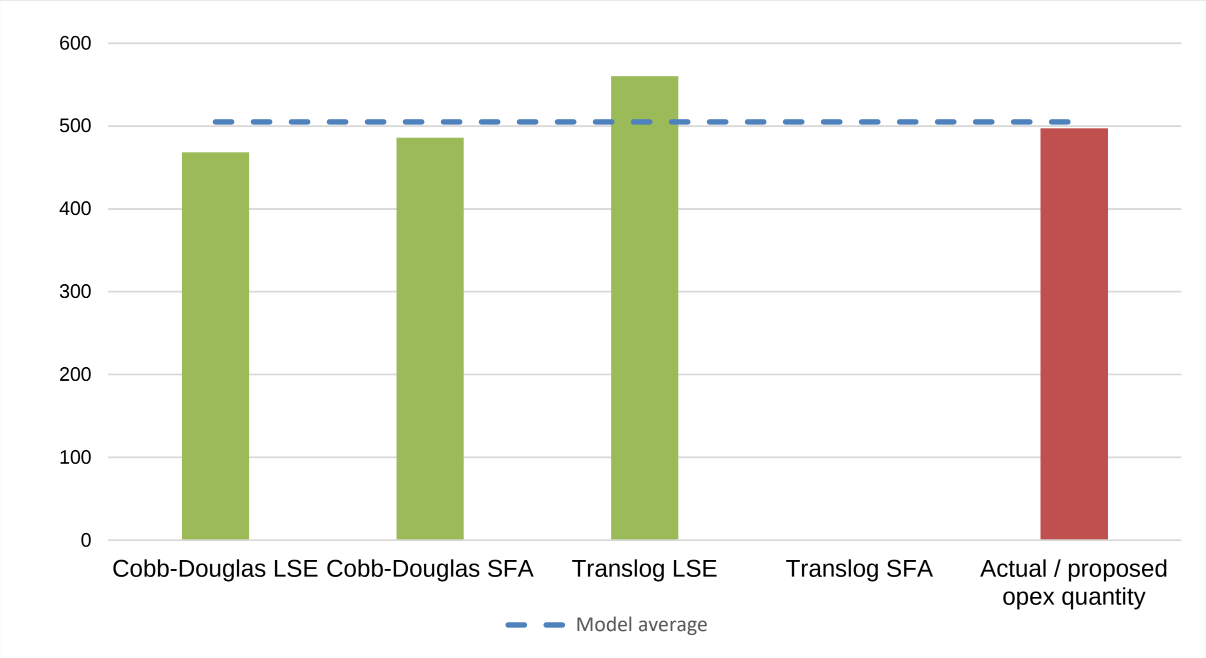


Source: Quantonomics, *Benchmarking results for the AER – Distribution,* November 2023; AER analysis.
Note: The Translog SFA model results have been excluded due to monotonicity violations.

[57] AER, Final Decision, *Jemena distribution determination 2021–26 – Attachment 6 – operating expenditure*, April 2021, p. 25.

[58] AER, *Draft decision, Attachment 6 – Operating expenditure – Ergon Energy – 2025–30 Distribution revenue proposal*, September 2024, pp. 22–25.

Figure 6.10 Estimates of efficient network services opex using data over the 2012–23 period



Source: Quantonomics, *Benchmarking results for the AER – Distribution,* November 2023; AER analysis.
Note: The Translog LSE model results have been excluded due to monotonicity violations. The Translog SFA results are excluded due to this model not converging during the modelling for the 2024 Annual Benchmarking Report.

Taking the above benchmarking analysis into account, we consider that Ergon Energy's base year opex is not materially inefficient and that we should continue to rely on revealed costs. Given this, we have relied on Ergon Energy's actual 2022–23 opex as the basis of our alternative estimate of total opex.

Consistent with our standard approach for the EBSS, as we are relying on Ergon Energy's revealed costs to forecast opex for the next period, we are also applying the EBSS penalties Ergon Energy has accrued in the current period, and applying the EBSS in the next regulatory period. Attachment 8 outlines our EBSS decision in more detail.

Submissions received on our draft decision and Ergon Energy's revised proposal[59] from Energy Queensland's Reset Reference Group (RRG) and the CCP30 were critical of inclusion of transition costs, and Ergon Energy's revised proposal that we not apply its EBSS penalties or the scheme in the next regulatory period.[60] The RRG noted that it was not convinced that the AER's standard approach to give transition costs when making an efficiency adjustment to base opex should be applied for Ergon Energy. The RRG asked the AER to require more evidence of transition plans and costs drivers before determining if transition costs are appropriate, and that the allocation of transition costs should be

59 Which relied on Ergon Energy's estimated 2023–24 opex for the base year.

60 CCP30, *Submission on Ergon Energy Energy's revised proposal and draft decision 2025–30,* January 2025, pp. 19 and 21; RRG, *Submission on Ergon Energy's revised proposal and draft decision 2025–30,* January 2025, pp. 35 and 38.

conditional on the businesses achieving efficiencies.[61] The CCP also submitted that transition costs are not warranted unless Ergon Energy has a clear and well-articulated plan to transition to an efficient level of costs in the next regulatory period.[62] CCP30 noted that Ergon Energy did not consult adequately or transparently on its decision to reverse its position between the initial and revised proposals on the application of the EBSS, and submitted that it thought Ergon Energy should bear the full penalties under our regulatory framework designed to encourage efficient delivery of distribution services.[63]

6.4.2 Adjustments to base year opex

Ergon Energy's revised proposal included $67.8 million in base year adjustments, or $339.2 million over the 2025–30 period.[64] These are largely for the same adjustments Ergon Energy proposed in its initial proposal, and we included in our draft decision,[65] with Ergon Energy updating costs to reflect actual expenditure for 2023–24. These adjustments are for the Electrical Safety Office levy, property leases, emergency response costs, actual debt raising costs and to for the final year increment.[66]

We have adjusted our alternative estimate of opex in the base year by –$29.4 million, or –$147.1 million over 5 years to:

- subtract $6.6 million for the Electrical Safety Office levy. This decreases our alternative estimate of total opex by $33.2 million over 5 years
- subtract $2.8 million for the reclassification of ongoing lease costs as capex in the 2025–30 period.[67] This decreases our alternative estimate of total opex by $14.1 million over 5 years.
- subtract $7.7 million for actual debt raising costs. This decreased our alternative estimate of total opex by $38.7 million over 5 years.
- subtract $12.2 million for the change in opex between 2022–23 and 2024–25. This decreased our alternative estimate by $61.1 million over 5 years. Our final year increment is materially larger than Ergon Energy's as our forecasts includes one additional year.

The reasons for the difference between our total adjustment and that of Ergon Energy is that we have used Ergon Energy's 2022–23 actual expenditure to calculate the adjustments, as opposed to 2023–24 in Ergon Energy's revised proposal, and have included the most recent inflation data. We have not included the emergency response cost adjustment, as the 2022–23 year was not subject to abnormal weather events.

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61 RRG, *Submission on Ergon Energy's revised proposal and draft decision 2025–30*, January 2025, p. 39.

62 CCP30, *Submission on Ergon Energy's revised proposal and draft decision 2025–30*, January 2025, p. 19.

63 CCP30, *Submission on Ergon Energy's revised proposal and draft decision 2025–30,* January 2025, p. 21.

64 Ergon Energy, *6.01 – Model – SCS Opex model*, November 2024.

65 AER, *Draft decision, Attachment 6 – Operating expenditure – Ergon Energy – 2025–30 Distribution revenue proposal*, September 2024, pp. 31–32.

66 Ergon Energy, *6.01 – Model – SCS Opex model*, November 2024.

67 Ergon Energy, *Response to information request, IR#066 – Output growth forecasts and base year adjustments,* 19 December 2024, p. 3.

6.4.3 Rate of change

We have included a rate of change that increases opex, on average, by 0.5% each year in our alternative estimate. This contributed $33.7 million to overall opex in our alternative estimate. This compares to Ergon Energy's average annual rate of change of 0.3%, contributing $20.5 million to its opex forecast.

Ergon Energy's revised proposal made some updates to its trend inputs to reflect actual data for 2023–24. Ergon Energy adopted a consistent approach for forecasting input price growth and output growth to its initial proposal. Consistent with our draft decision, we have largely included the updated input forecasts in our alternative estimate for the final decision. However, we did not include Ergon Energy's revised productivity forecast and ratcheted maximum demand forecasts. The overall updates included:

- **price growth** – Ergon Energy updated its WPI forecast using our standard approach of averaging updated WPI forecasts provided by its consultant, Oxford Economics, and our consultant's, Deloitte Access Economic, August 2024 WPI forecasts.[68] We have further updated our WPI forecast with the latest Deloitte Access Economic forecasts.[69]
- **output growth** – Ergon Energy updated its customer numbers, circuit length and maximum demand to reflect actual data for 2023–24 and provided updated forecasts.[70] We accepted Ergon's updated customer numbers and circuit length forecasts. We did not accept the ratcheted maximum demand forecasts, and have substituted alternative values into our opex forecast. This is explained further below.
- **Productivity growth** – Ergon Energy included a 1% productivity forecast. We have used 0.5% productivity growth forecast, consistent with our standard approach.

For the output weights, Ergon Energy stated that it used values based on our preliminary Quantonomics Report.[71] We have updated the output weights consistent with our 2024 Annual Benchmarking Report.

Table 6.3 shows Ergon Energy's revised proposal, our final decision for each component of the rate of change and the differences in the values.

Table 6.3 Forecast annual rate of change in opex, %

	2025–26	2026–27	2027–28	2028–29	2029–30
Ergon Energy's proposal					
Price growth	0.7	0.5	0.5	0.6	0.7
Output growth	0.8	0.5	0.8	0.4	0.6
Productivity growth	1.0	1.0	1.0	1.0	1.0
Rate of change	0.5	0.0	0.4	0.1	0.4

68 Ergon Energy, *6.01 – Model – SCS Opex model*, November 2024.

69 Deloitte Access Economics, Labour price growth forecasts, March 2025, p. 10.

70 Ergon Energy, *2025–30 Revised regulatory* proposal, November 2024, p. 90

71 Ergon Energy, *2025–30 Revised regulatory* proposal, November 2024, p. 90.

	2025–26	2026–27	2027–28	2028–29	2029–30
AER alternative estimate					
Price growth	0.7	0.6	0.5	0.6	0.7
Output growth	0.4	0.4	0.4	0.4	0.4
Productivity growth	0.5	0.5	0.5	0.5	0.5
Rate of change	0.5	0.5	0.4	0.4	0.5
Difference	**0.0**	**0.5**	**0.0**	**0.4**	**0.2**

Source: Ergon Energy, *6.01 – Model – SCS Opex model*, November 2024: AER analysis.
Note: The rate of change = (1 + price growth) × (1 + output growth) × (1 – productivity growth) – 1. Numbers may not add up to totals due to rounding. Amounts of '0.0' and '–0.0' represent small non-zero values and '–' represents zero.

Ratcheted maximum demand

In response to an information request, Ergon Energy informed us that the updated maximum demand forecasts for the 2025–30 period were based on a “native load” definition of the maximum demand,[72] which includes an estimate of the potential load that may be met by major embedded generators.[73] Our standard approach to measuring maximum demand for the purposes of forecasting total opex is to use a ‘network load’ definition,[74] which is not adjusted for contributions made by major embedded generators. We consider this definition best reflects the network demand or output that the network is delivering to end customers.

To implement our standard approach, we sought updated forecasts of maximum demand net of embedded generation. Ergon Energy was unable to provide updated forecasts on this basis, but did provide historical values for native demand, noting that the last 3 years (2021–2024) represented a robust estimate of the difference between network and native load maximum demand (i.e. the difference reflecting the potential load or network demand that could be met by major embedded generation).[75] We calculated the average difference between the most recent 3 years of these actuals to get a best available estimate of the recent size of major embedded generation. We subtracted this estimate from the revised forecasts of native load maximum demand Ergon Energy provided in the revised proposals. We then ratcheted the resulting maximum (network) demand forecast against the historic data to generate the ratcheted maximum demand numbers used in our alternative estimate of total opex.

72 Ergon Energy, *Response to AER information request, IR#076 – actual/forecast opex, choice of base year, emergency response, maximum demand, EBSS, 28 January 2025*, p. 7– 8; Ergon Energy, *Response to AER information request, IR#085 – maximum demand, EBSS*, 18 February 2025, p. 1.

73 Ergon Energy, *Response to AER information request, IR#076 – actual/forecast opex, choice of base year, emergency response, maximum demand, EBSS*, 28 January 2025, p. 7– 8.

74 Specifically, for actual maximum demand we use raw non-coincident maximum demand at the transmission connection point - line number DOPSD0107 of the EB RIN.

75 Ergon Energy, *Response to AER information request, IR#085 – Maximum demand forecasts*, 18 February 2025, p.1–2.

6.4.4 Step changes

In developing our alternative estimate for the draft decision, we include prudent and efficient step changes for cost drivers such as new regulatory obligations or efficient capex to opex trade-offs. As we explain in the AER's Expenditure forecast assessment guideline for electricity, we will generally include a step change if the efficient base opex and the rate of change in opex of an efficient service provider does not already include the proposed cost for such items and they are required to meet the opex criteria.[76]

6.4.4.1 Smart meter data acquisition and analysis step change

We have not included the smart meter data and analysis step change in our alternative estimate of opex for the final decision. This is consistent with our alternative estimate draft decision, and is because we are not satisfied that all proposed components of this step change reflect prudent and efficient expenditure. While we are satisfied the uplift associated with Ergon Energy's proposed business case's Option 1 is likely prudent, we consider this uplift to be already provided for through rate of change in our base-step-trend opex forecasting approach. Including an additional allowance would therefore double count costs.

Table 6.4 Ergon's smart meter data step change ($million, 2024–25)

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
Ergon's revised proposal	2.5	1.4	1.7	2.0	2.3	10.0
AER final decision	–	–	–	–	–	–
Difference	–2.5	–1.4	–1.7	–2.0	–2.3	–10.0

Source: Ergon, *6.01 – Model – SCS Opex model*, November 2024; AER analysis.
Note: Numbers may not add up to totals due to rounding.

Ergon Energy's initial proposal included $6.8 million for the acquisition and analysis of smart meter data to increase its low voltage network visibility.[77] We discuss this step change, our assessment and the reasons for not including this step change in further detail in our draft decision.[78]

For its revised proposal, Ergon Energy included a higher amount of $10.0 million, or $3.2 million higher than its initial proposal, and $10.0 million higher than our alternative estimate for the draft decision. Ergon Energy stated these costs reflect both the April 2024 AEMC's Accelerating smart meter data deployment draft decision, and updates in response to our draft decision. Most relevantly, this included updated inputs for less frequent data provision than initially assumed, and for data acquisition costs for one year, because of a one-year delayed implementation timeline for the respective AEMC rule change.[79]

76 AER, *Final decision, Expenditure Forecast Assessment Guideline – Electricity Distribution*, October 2024, p. 24.

77 Ergon Energy, *2025–30 Regulatory Proposal,* January 2024, pp. 137–139.

78 AER, *Draft decision, Attachment 6 – Operating expenditure Ergon – 2025–30 Distribution revenue* proposal, September 2024, pp. 39–43.

79 Ergon, *6.04A – Business case – Smart meter data* acquisition, November 2024, p. 5.

We assessed the information provided in Ergon Energy's revised proposal, including information received in its smart meter data business case, the smart meter data NPV model, and information received through information requests.

Overall, we consider Ergon Energy has not provided sufficient evidence to support a change to our draft decision approach. We consider that although Ergon Energy has updated some of its assumptions in response to our draft decision, we consider the revised assumptions overstate the likely benefits arising from live smart meter data. We also note the recent AEMC Direction paper on real-time data for consumers, which supports our position that, consistent with the use cases as proposed by Ergon Energy, the likely incremental benefits gained from real-time data are not significant enough to outweigh the additional costs, compared to the free daily data.[80] Overall, the AEMC also considers that extending access to distributors for real-time data, additional to providing access the free daily data, is not in the long-term interest of consumers.[81]

Our analysis showed that removing the overstated live smart meter data benefits, especially related to reliability and safety, results in the preferred, or the highest NPV option, being the base case Option 1.

In terms of reliability benefits, Ergon Energy considers that live data will enable improved response time by 60%. However, we consider this to be an improbable scenario, and essentially implies the greatest time in the outage-to-repair incident is the portion between when customers first lose power and once Ergon Energy becomes aware of the outage. This is because this is the only likely achievable time saving through more frequent data provision. We note that all other activities will remain unaffected by the notification rate (e.g. crew mobilisation, journey time and physical outage repair remains constant in both scenarios). Through an information request, Ergon Energy also clarified that it currently does not have a breakdown of the times for each individual response component.[82] Based on this, we are therefore not satisfied that an appropriate method was used to calculate any likely reduction in response time achievable through faster outage notification.

In terms of the safety benefits, we consider Ergon Energy's revised proposal did not provide sufficient information to suggest live data will allow for a materially better safety outcome, compared to daily data frequency. We consider that Ergon Energy overstated the capacity to identify 60% of faults using smart meter data and the ability to identify more faults using live data.[83] That is, the information provided suggests that daily data will improve the potential safety outcomes, without clarifying whether, or how, higher frequency data provision may impact this outcome. Considering the above, our analysis supports Ergon Energy's Option 1 as the preferred and highest NPV option.

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80 AEMC, National Electricity Amendment (Realtime data for consumers) Rule 2025, 30 January 2025, p. 43.

81 AEMC, National Electricity Amendment (Realtime data for consumers) Rule 2025, 30 January 2025, p. vi.

82 Ergon Energy, *Response to AER information request IR#078 – Smart meter data step change, Q10–Q11*, 29 January 2025.

83 Ergon Energy, *6.04A – Business case – Smart meter data* acquisition, November 2024, p. 6.

We further tested whether the proposed costs of Option 1 were provided for through the rate of change in our base-step-trend forecasting approach,[84] including though any relevant amounts in Ergon Energy's 2022–23 base year. In response to our information request, Ergon Energy confirmed that it's 2022–23 base year already includes an amount for smart meter data.[85] While we consider that Option 1 is likely to be a prudent and efficient approach to uplift Ergon Energy's smart meter data capabilities, we consider the likely prudent and efficient amounts will therefore already be provided through rate of change and our base-step-trend forecasting approach.

For these reasons, we have not included additional costs for this step change in our final decision.

6.4.5 Category specific forecasts

Ergon Energy's proposal included one category specific forecast, which was not forecast using the base-step-trend approach, for debt raising costs. We have included a category specific forecast for debt raising costs in our alternative estimate of total opex.

6.4.5.1 Debt raising costs

We have included debt raising costs of $40.7 million in our alternative estimate, or $0.4 million lower than the amounts proposed by Ergon Energy.

Table 6.5 Debt raising costs ($million, 2024–25)

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
Ergon Energy's revised proposal	7.9	8.1	8.2	8.4	8.5	41.1
AER final decision	7.9	8.0	8.2	8.3	8.4	40.7
Difference	0.0	–0.0	–0.1	–0.1	–0.2	–0.4

Source: Ergon Energy, *6.01 – Model – SCS Opex model*, November 2024; AER analysis.
Note: Number may not add due to rounding; Values of '0.0' and '–0.0' represent small non-zero amounts

Debt raising costs are transaction costs incurred each time a business raises or refinances debt. Our preferred approach is to forecast debt raising costs using a benchmarking approach rather than a service provider's actual costs in a single year. This provides consistency with the forecast of the cost of debt in the rate of return building block. We used our standard approach to forecast debt raising costs, which is discussed further in Attachment 3 to the final decision.

84 AER, *Final decision, Expenditure Forecast Assessment Guideline – Electricity Distribution*, October 2024, p. 24.

85 Ergon Energy, *Response to AER information request, IR#019 – DER,* 10 May 2024, Q4, p. 3.

Shortened forms

Term	Definition
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
capex	capital expenditure
MPFP	Capital multilateral partial factor productivity
CCP30	Consumer Challenge Panel, sub-panel 30
CPI	consumer price index
DNSP	Distribution network service provider
EA	Enterprise Agreement
EBSS	efficiency benefit sharing scheme
NER or the Rules	National Electricity Rules
NSP	network service provider
MTFP	Multilateral total factor productivity
opex	operating expenditure
PPI	partial performance indicator
RRG	Energy Queensland Reset Reference Group
RIN	regulatory information notice
SCS	standard control services
OEF	Operating environmental factors
RRG	Energy Queensland’s Reset Reference Group
WPI	Wage price index