Final Decision

Energex Electricity Distribution Determination 2025 to 2030

(1 July 2025 to 30 June 2030)

Attachment 6
Operating expenditure

April 2025

AUSTRALIAN
ENERGY
REGULATOR

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601
Email: aerinquiry@aer.gov.au
Tel: 1300 585 165

AER reference: AER213703

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 Energex 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

Attachment 8 – Efficiency benefit sharing scheme

Attachment 13 – Classification of services

Attachment 14 – Control mechanisms

Attachment 16 – Alternative control services

Attachment 18 – Connection policy

Attachment 19 – Tariff structure statement

Attachment 20 – Metering services

Contents

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 Energex’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 Energex’s total opex forecast of $2,510.2 million ($2024–25),[1] including debt raising costs, for the 2025–30 period.[2] This is primarily driven by us not accepting Energex’s use of 2023–24 as the base year to forecast its revised opex proposal, and our substitution of Energex’s actual 2022–23 opex as the base year for our alternative estimate of total opex.

In our draft decision, which accepted Energex’s initial total opex forecast, we used Energex’s estimated 2023–24 base year opex in our alternative estimate of total opex.[3] 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 Energex’s revised proposal. Further, as Energex 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 Energex’s increasing opex, and whether 2023–24 or another year, would be most the appropriate base year. We asked Energex to consider these issues and update its rationale for the choice of base year in the revised proposal.

Energex 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. Energex 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] Energex’s revised proposal reported actual opex for 2023–24 that was 15.1% higher than the estimate it included in its initial proposal. Energex 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 storm events that occurred in 2023–24 from its 2023–24 base

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

2 Energex, *6.01 – Model – SCS Opex model,* November 2024.

3 AER, *Draft decision, Attachment 6 – Operating expenditure – Energex – 2025–30 Distribution revenue proposal*, September 2024, pp. 11–14.

4 Energex, *2025–30 Revised Regulatory* Proposal, November 2024, p. 71.

opex.[5] Together, these changes resulted in Energex's revised total opex proposal being $225.3 million (9.9%) higher than its initial proposal and our draft decision.

To select a base year that best reflects the prudent and efficient costs Energex would need to deliver the required services over the next regulatory period, we assessed Energex'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 Energex'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 Energex'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 Energex needs to deliver the required services over the next regulatory period.

Given the above, we have used Energex's actual opex for 2022–23 as the base year for our alternative estimate of total opex for the final decision.[8] As we have not found Energex's 2022–23 actual opex to be materially inefficient, we have not applied an efficiency adjustment or included transition costs, as proposed by Energex for its 2023–24 base year. We also did not apply Energex's proposed base adjustment for its 2023–24 storms, because these costs were not incurred in 2022–23. We have largely applied other base adjustments and trend consistent with Energex's revised proposal and our draft decision, with the amounts updated using Energex's actual expenditure for 2022–23. The differences between Energex'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 Energex's revised proposal, that are not primarily driven by the change of base year, include that we:

- substituted Energex'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, which Energex had not done in its revised proposal, reducing the output growth forecast in our alternative estimate by $25.3 million, relative to Energex's revised proposal.
- included $4.7 million for Energex's revised proposal smart meter data step change, which is $11.0 million less than the $15.7 million proposed by Energex. This approach is consistent with our draft decision, where we provided for costs required to upgrade Energex's analytics and data management capabilities, but excluded costs related to the

5 Energex, *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.

8 AER, *Final decision*, Energex – 2025–30 Distribution revenue proposal – Opex model, April 2025.

acquisition of live smart meter data. This was because we were not satisfied live data would provide incremental benefits above those achievable from free daily data.

Accounting for the above changes, our alternative estimate of total forecast opex is $2,442.2 million. This is materially below ($68.0 million, or 2.7 %) Energex's revised proposal total opex forecast of $2,510.2 million.[9] Our final decision is therefore to substitute our total opex forecast of $2,442.2 million, including debt raising costs, for the 2025–30 period, as reasonably reflecting the opex criteria.[10]

Table 6.1 sets out Energex'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 Energex'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.

---

9 Energex, *6.01 – Model – SCS Opex model,* November 2024.

10 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 Energex's proposal and our final decision ($million, 2024–25)

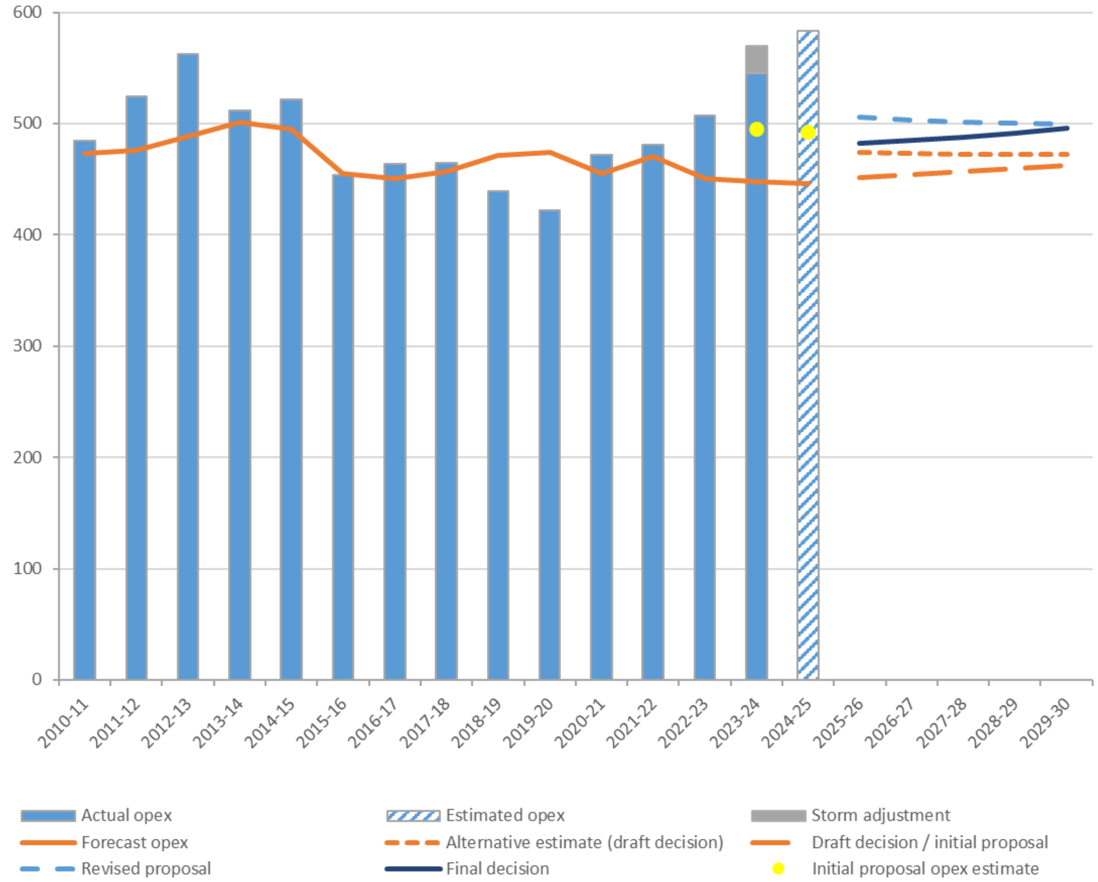
Driver	Energex proposal / AER draft decision	Energex revised proposal	AER Final decision	Difference, $million	Difference, %
Reported opex in relevant base year*	**2,474.0** *2023–24	**2,749.9** *2023–24	**2,497.5** *2022–23	**–252.4**	**–10.1%**
Efficiency adjustment	**–138.9**	**–104.4**	**–**	**104.4**	**4.2%**
Transition cost	**–**	**42.3**	**–**	**–42.3**	**–1.7%**
Base adjustment – emergency response storm costs	–	–123.6	–	123.6	4.9%
Base adjustment – ESO levy	–68.2	–72.7	–69.9	2.7	0.1%
Base adjustment – Property leases	–33.5	–25.5	–17.7	7.8	0.3%
Total base year adjustments	**–101.7**	**–221.8**	**–87.6**	**134.1**	**5.3%**
Final year increment	–12.7	–12.8	–24.1	–11.3	–0.5%
Remove category specific forecasts	–32.4	–40.3	–40.8	–0.6	0.0%
Trend: Output growth	58.8	70.6	45.3	–25.3	–1.0%
Trend: Price growth	49.4	43.0	43.5	0.5	0.0%
Trend: Productivity growth	–65.6	–70.9	–35.3	35.6	1.4%
Total trend	**42.6**	**42.6**	**53.4**	**10.8**	**0.4%**
Step change: Smart Meter Data Storage	14.6	15.7	4.7	–11.0	–0.4%
Total step changes	**14.6**	**15.7**	**4.7**	**–11.0**	**–0.4%**
Category specific forecasts	–	–	–	–	–
Total opex, excluding debt raising costs	**2,245.6**	**2,471.2**	**2,403.0**	**–68.2**	**–2.7%**
Debt raising costs	39.3	39.0	39.2	0.2	0.0%
Total opex, including debt raising costs	**2,284.9**	**2,510.2**	**2,442.2**	**–68.0**	**–2.7%**

Source: Energex, *6.02 – Model – SCS Opex Model,* January 2024*;* Energex, *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 Energex we have included in this final decision for the 2025–30 period (dark blue line), to Energex's revised total opex proposal (blue dashed line), as well as Energex's actual and estimated opex in the previous and current regulatory control period (the blue bars). We have also included Energex's initial proposal, which was also our draft decision for the 2025–30 period (orange long dashed line). The yellow dots show Energex'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: Energex, 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; Energex, 2025–30 Regulatory proposal, November 2024; Energex, *Response to AER information request IR065, ;28 January 2025;* AER analysis.

Our final decision total opex forecast is:

- $171.3 million (7.5%) higher than the opex forecast we approved in our final decision for the 2020–25 regulatory control period[11]
- $171.0 million (–6.5%) lower than Energex's actual (and estimated) opex in the 2020–25 regulatory control period
- $157.3 million (6.9%) higher than Energex's initial proposal, which we accepted in our draft decision.

6.2 Energex's revised proposal

Energex included total forecast opex of $2,510.2 million in its revised proposal for the 2025–30 period, as set out in Table 6.2. This is $103.0 million (–3.9%) lower than Energex's actual and estimated opex for the 2020–25 period, and $225.3 million (9.9%) higher than its initial proposal and our draft decision.[12]

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

	2025–26	2026–27	2027–28	2028–298	2029–30	Total
Total opex excluding debt raising costs	498.0	495.4	493.6	492.6	491.6	2,471.2
Debt raising costs	7.8	7.8	7.8	7.8	7.8	39.0
Total opex	**505.8**	**503.2**	**501.4**	**500.4**	**499.4**	**2,510.2**

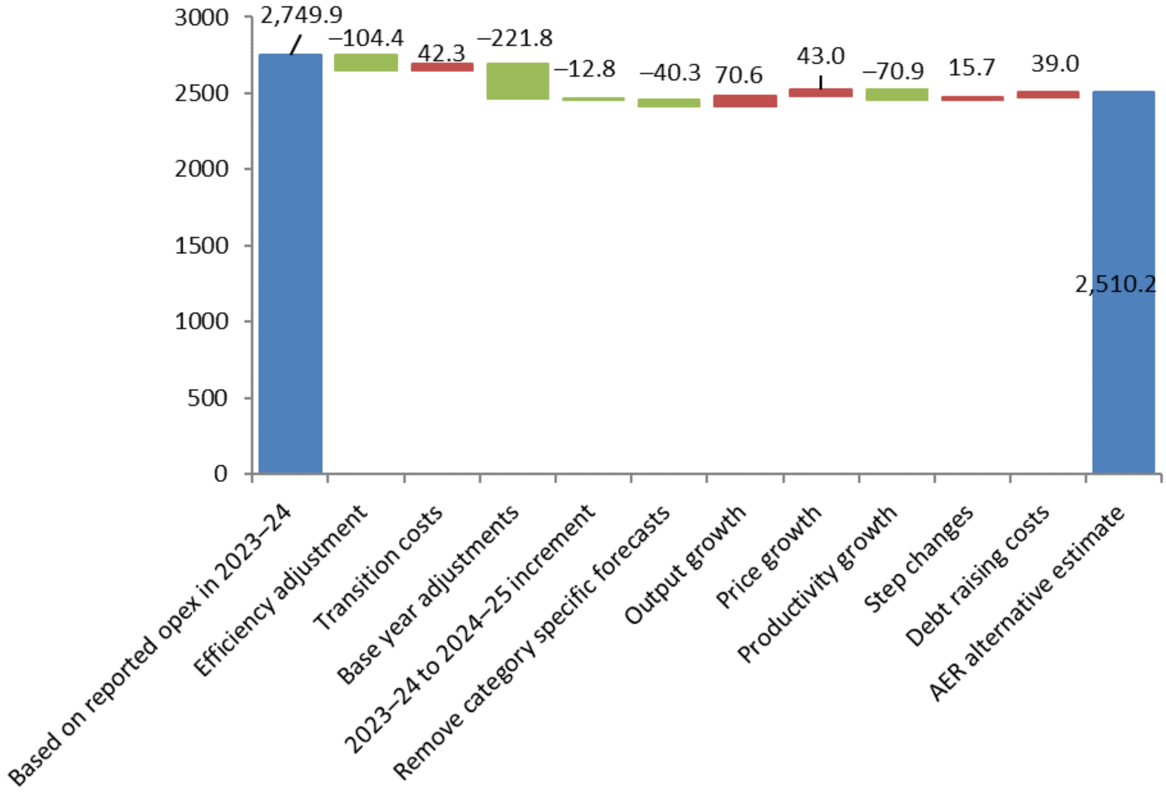
Source: Energex, *6.01 – Model – SCS Opex model*, November 2024.
Note: Numbers may not add up due to rounding.

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

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

12 Comparisons are inclusive of debt raising costs.

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



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

Energex 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, Energex:[13]

- used opex in 2023–24 as the base from which to forecast ($2,749.9 million)
- subtracted $104.4 million as an efficiency adjustment
- added $42.3 million for transition costs
- adjusted its total base year forecast opex by subtracting $221.8 million for:
  - Electrical Safety Office levy that will be treated as a jurisdictional scheme in the forecast period ($72.7 million)
  - property lease costs that will be reported as capital expenditure (capex), rather than opex, in the forecast period ($25.5 million)
  - emergency response storm costs, to account for significant weather events during 2023–24, including the Gold Coast December 2023 storm event, ($123.6 million)

13 Energex, *6.01 – Model – SCS Opex model*, November 2024.

- subtracted $40.3 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 $12.8 million
- applied a rate of change comprising of:
  - output growth ($70.6 million)
  - real price growth ($43.0 million)
  - productivity growth of 1.0% per year (–$70.9 million).
- added one step change totalling $15.7 million for Smart meter data
- added $39.0 million of debt raising costs, to arrive at total forecast opex of $2,510.2 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 Energex or Ergon 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.[14] Further, the RRG noted that:

- Energex's and Ergon Energy'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 Energex's or Ergon's business' costs in 2025–30.[15]
- 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 Energex or Ergon Energy. 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.[16]

The CCP emphasised that there are significant changes in Energex's and Ergon Energy's revised proposal that were not consulted on adequately or transparently, including:[17]

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

---

14 RRG, *Submission on Energex's revised proposal and draft decision 2025–30*, January 2025, p. 31.

15 RRG, *Submission on Energex's revised proposal and draft decision 2025–30*, January 2025, pp. 35–36.

16 RRG, *Submission on Energex's revised proposal and draft decision 2025–30*, January 2025, pp. 33–35.

17 CCP30, *Submission on Energex's revised proposal and draft decision 2025*–30, January 2025. p. 4.

The CCP 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 Energex has flagged.[18]

The CCP also expressed doubt that Energex or Ergon will be able to meet the revised opex forecasts,[19] 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.[20]

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).[21]

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'.[22] In doing so, we must have regard to the opex factors specified in the National Electricity Rules (NER).[23]

The *Expenditure forecast assessment guideline* (the Guideline), together with an explanatory statement, sets out our assessment approach in detail.[24] 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.[25]

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.[26] 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

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

19 CCP30, *Submission on Energex's revised proposal and draft decision 2025*–30, January 2025. p. 12.

20 CCP30, *Submission on Energex's revised proposal and draft decision 2025*–30, January 2025. p. 19.

21 NER, cl. 6.5.6(a).

22 NER, cl. 6.5.6(c).

23 NER, cl. 6.5.6(e).

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

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

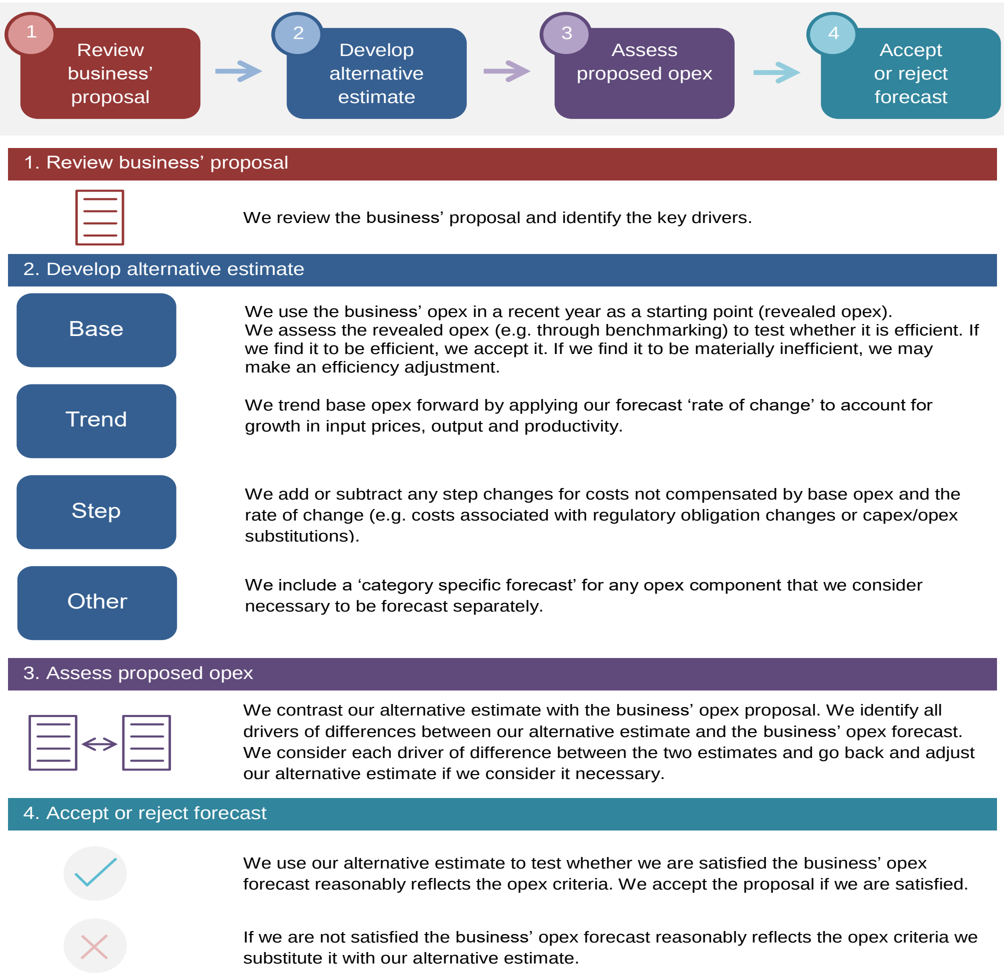
26 A 'top-down' approach forecasts total opex at an aggregate level, rather than forecasting individual projects or categories to build a total opex forecast from the 'bottom up.'

forecast.[27] If we are not satisfied, we substitute the business's forecast with our alternative estimate that we are satisfied reasonably reflects the opex criteria.[28]

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.[29]

Figure 6.3 summarises the ‘base-step-trend’ forecasting approach.

Figure 6.3 Our opex assessment approach



6.3.1 Interrelationships

In assessing Energex’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:

- 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

27 NER, cl. 6.5.6(c).

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

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

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 Energex 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 Energex'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 Energex's total opex forecast of $2,510.2 million, including debt raising costs, for the 2025–30 period.[30] This is primarily driven by us not accepting Energex'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 Energex's 2022–23 actual opex to be materially inefficient, we have not applied an efficiency adjustment or included transition costs, as proposed by Energex for its proposed 2023–24 base year. We also did not apply Energex's proposed base adjustment for its 2023–24 storms, as these costs were not incurred in 2022–23. We have largely applied the other base adjustments and trend consistent with Energex's revised proposal and our draft decision, with amounts for these components updated based on the 2022–23 base year. The differences between Energex'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 Energex's revised proposal that are not primarily driven by the change of base year include that we:

- substituted Energex'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, which Energex did not apply in its revised proposal, reducing the output growth forecast in our alternative estimate by $25.3 million, relative to Energex's revised proposal.
- included $4.7 million for Energex's revised proposal smart meter data step change, which is $11.0 million less than the $15.7 million proposed by Energex. This is consistent with our draft decision approach, where we provided for costs required to

30 Energex, *6.01 – Model – SCS Opex model*, November 2024.

uplift Energex's analytics and data management capabilities, but excluded costs related to the acquisition of live smart meter data. This is because we were not satisfied live data would provide prudent incremental benefits above those achievable from free daily data.

Accounting for the above changes, our alternative estimate of total forecast opex is $2,442.2 million. This is $68.0 million (–2.7%) lower than Energex's revised proposal total opex forecast of $2,510.2 million.[31] Our final decision is therefore to substitute total opex forecast of $2,442.2 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 Energex, 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 Energex 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 Energex's proposed use of 2023–24 as the base year to forecast our alternative estimate of total opex, instead relying on Energex's actual opex for 2022–23.

In our draft decision,[33] in which we accepted Energex's initial total opex forecast, we used Energex'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 Energex's revised proposal. Further, as Energex 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 Energex's increasing costs in the current period, and whether 2023–24 or another year, would be the most appropriate base year. We asked Energex to consider these issues and update its rationale for choice of base year in the revised proposal.

Energex 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. Energex further submitted that it did not consider 2022–23 as an appropriate choice of base year as 'it

---

31 Energex, *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. 6.5.5(d).

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

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]

Energex's actual opex for 2023–24 is 15.1% higher than the estimate it included in its initial proposal. Figure 6.1 shows that Energex'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. Energex 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, Energex further noted in its revised proposal that its actual 2023–24 base year opex had been impacted by significant weather events, including a major Gold Coast storm event in December 2023.[36] Energex estimated that these events contributed an estimated $23.6 million ($2023–24) in one-off emergency response storm costs to its 2023–24 base year opex (the grey component in Figure 6.1).[37] Energex 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 Energex's 2023–24 opex increased significantly even with the one-off costs removed, we sought additional information from Energex to understand the reasons for the rapid escalation in its costs. Through responses to information request, meetings with Energex, 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 Energex's internal labour costs, resulting from increases in wage and non-wage costs under Energex'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 Energex'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.

---

34 Energex, *2025–30 Revised Regulatory* Proposal, November 2024, pp. 67 & 71.

35 Energex, *2025–30 Revised Regulatory* Proposal, November 2024, p. 71.

36 Energex, *2025–30 Revised Regulatory* Proposal, November 2024, p. 72.

37 Energex'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 Energex, *2025–30 Revised Regulatory* Proposal, November 2024, p. 72.

39 Fair Work Commission, *Energy Queensland Union Collective Agreement 2024 Electrical power industry*; 3 November 20220; Fair Work Commission, *Energy Queensland Union Collective Agreement 2024 Electrical power industry*, 2 July 2024.

Commenting on Energex'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 Energex 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]

Energex 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 11.5% efficiency adjustment to its 2023–24 base year.[41] Energex noted that the size of the efficiency adjustment decreased to 4.2% if its estimated one-off emergency response storm costs were removed.[42] Consistent with the approach used in our draft decision, and Energex's revised proposal, we reviewed Energex's actual 2023–24 opex using our 2024 benchmarking results, and agree with Energex's findings that its actual 2023–24 opex, both with and without the proposed adjustment for one-off storm costs, is materially inefficient and would require an efficiency adjustment to adjust it to a lower level of 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 Energex's proposed 2023–24 base year, as well as 2022–23, the third year of the current regulatory period. We considered the information Energex provided explaining the drivers of its increasing costs, particularly 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

---

40 RRG, *Submission on Energex's revised proposal and draft decision 2025–30*, January 2025, p. 32.

41 Energex, *2025–30 Revised Regulatory* Proposal, November 2024, p. 71.

42 Energex, *2025–30 Revised Regulatory* Proposal, November 2024, p. 72.

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.

consistent with Energex's revealed costs of the network. Having regard to all the above, we consider that using Energex'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, Energex's actual 2023–24 opex:

- is not reflective of Energex's revealed costs over the current and previous regulatory periods
- includes significant one-off costs, including the emergency response costs Energex 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 Energex'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 Energex'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 Energex'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 Energex'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 Energex's costs over time.

The trend escalation of labour costs is forecast using the average of wage price index (WPI) forecasts provided by Energex's and our consultants. Wage growth over the current regulatory period is forecast to be positive in real terms (i.e. CPI plus) in the trend we are applying.[50] Energex 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 Energex's actual wage cost growth. While the WPI forecasts do not directly take changes in non-wage 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

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

49 Energex, *2025–30 Revised Regulatory* Proposal, November 2024, pp. 67 & 71.

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

51 AER meeting with Energex, 14 February 2025.

applied to Energex's 2022–23 opex also provides for the efficient escalation of Energex's non-wage related labour costs.

Having regard to the above, we consider that Energex's 2022–23 opex reasonably reflects the prudent and efficient costs it will needs 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 Energex'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 Energex's actual opex decreased between the 2010–15 regulatory period where its average annual opex was $521.1 million, and 2015–20 regulatory period where its average annual opex had reduced to $448.7 million. In 2018–19 and 2019–20 (the last 2 years of the previous regulatory period) Energex's opex was below our forecast by $31.9 million (6.8%), and $51.9 million (11.0%) respectively. Over the 2015–20 regulatory control period, as a whole Energex's total actual opex was $63.6 million (2.8%) below our forecast, in contrast to the preceding 2010–15 period over which Energex's actual opex exceeded our forecast by $171.4 million (7.0%).

Since 2020–21, we have seen a steep upward trend in Energex's opex with opex increasing in each year of the current regulatory period. Energex's opex has increased from $471.6m in 2020–21 to $569.9 million in 2023–24, Energex's proposed base year, and is forecast to increase further to $582.9 million in 2024–25, the final year of the current regulatory period. Energex's opex is forecast to exceed our allowance for the 2020–25 period by $342.4 million (15.1%).

Energex 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 with growth in its capital program.[52] We also note that the actual and estimated opex for 2023–24 and 2024–25, respectively, reported in Energex'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 Energex's previous and new enterprise agreement (EAs) we understand the significant increases in 2023–24 and 2024–25 are driven by a combination of significant increases in internal and external labour costs

[52] Energex, *Response to AER information request IR#039*, 12 July 2024.

resulting from increases in wage and non-wage costs under Energex'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 Energex'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 Energex's opex over time

We have used our benchmarking tools and other cost analysis to assess and establish whether Energex is operating relatively efficiently. Our benchmarking results over the long and short time periods indicate that Energex has historically been amongst the mid to lower performing distribution network service providers (DNSPs).[53]

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 Energex to other distribution businesses in the National Electricity Market. These efficiency scores do not account for the presence of OEFs.

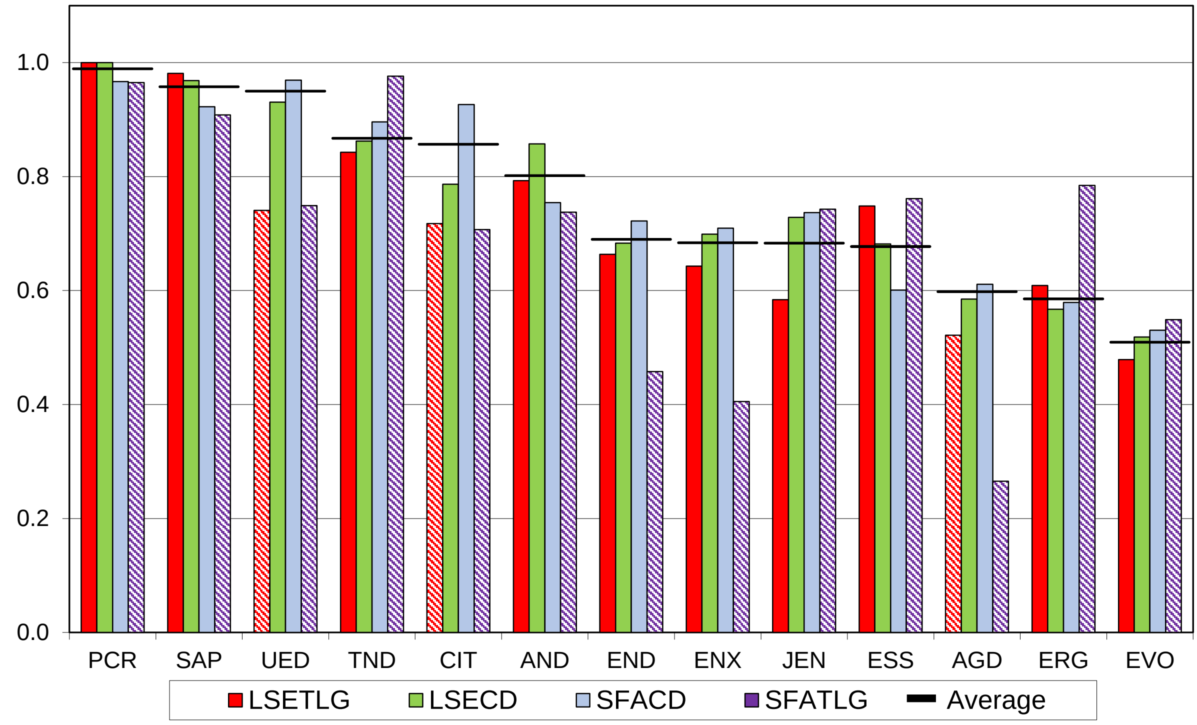
Econometric opex cost function benchmarking results from the *2024 Annual Benchmarking Report* are presented in Figure 6.4 over the long period, and in Figure 6.5 over the short period. The results indicated that when examined over time, Energex's opex has been operating somewhat below our 0.75 benchmarking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

Figure 6.4 shows that over the long period Energex is ranked 8th out of 13 DNSPs (with an average efficiency score of 0.68), while Figure 6.5 shows that Energex is ranked 9th over the short period (with an average efficiency score of 0.69). 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 Energex's efficiency scores.

---

53 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.

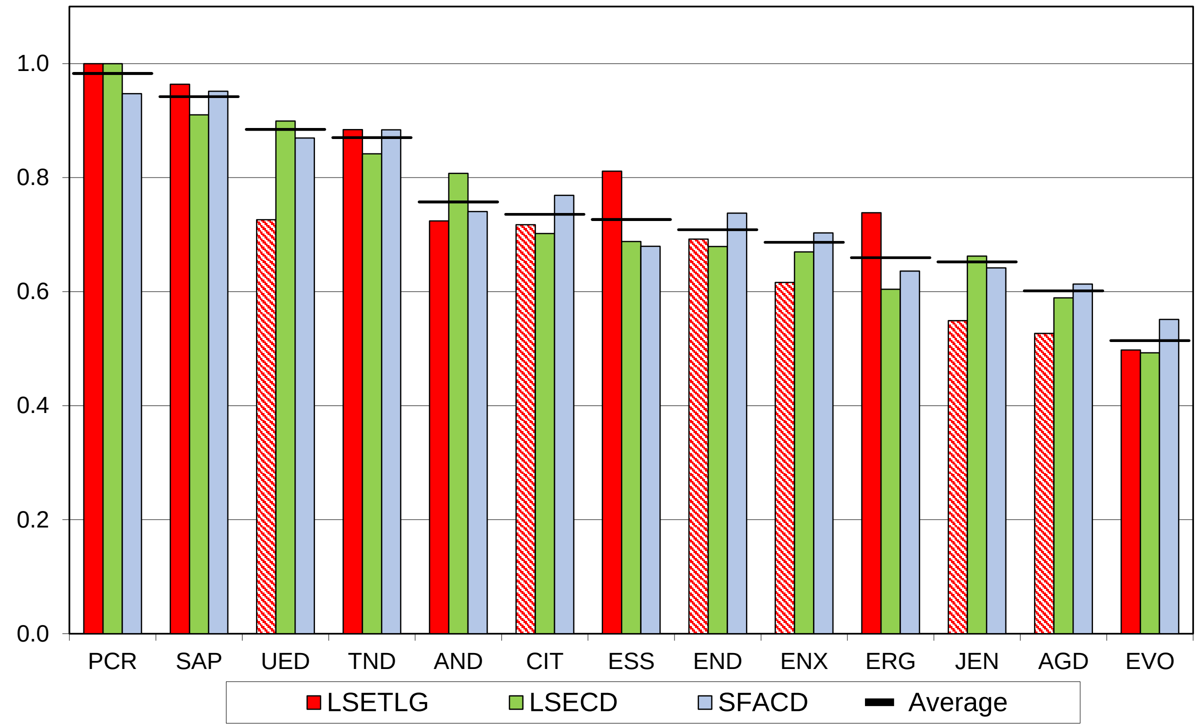
Figure 6.4 Distribution businesses' average opex efficiency scores, 2006–23



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.

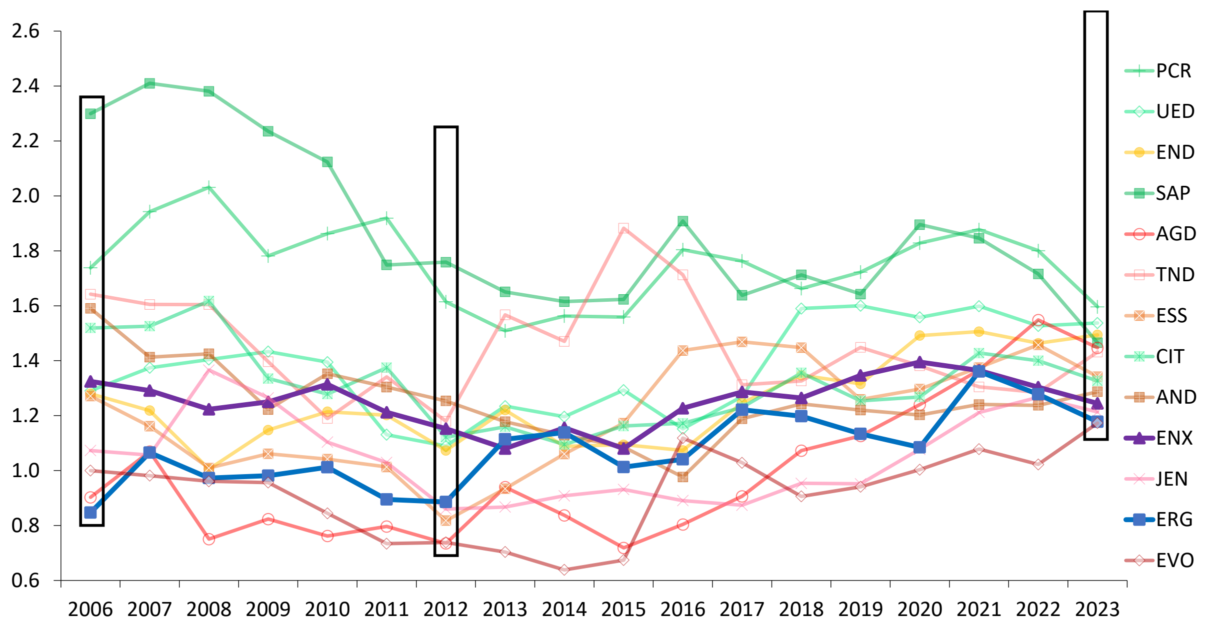
Note: Columns with a hatched pattern represent results that do not satisfy the monotonicity requirement (that an increase in output is only achieved with an increase in opex) and are not included in the model-average efficiency score for each DNSP (which is represented by the black horizontal line).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

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 Energex's relative performance declined between 2006–15, with its opex MPFP ranking falling from 6th out of 13 DNSPs in 2006, to 9th by 2015. Its relative performance improved from 2015 to 2020 reflecting decreases in opex, with Energex's ranking subsequently rising to 5th. In more recent years Energex's relative performance has once again trended downward due to increases in opex exceeding increases in network outputs, and its ranking as a result has dropped to 10th.

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



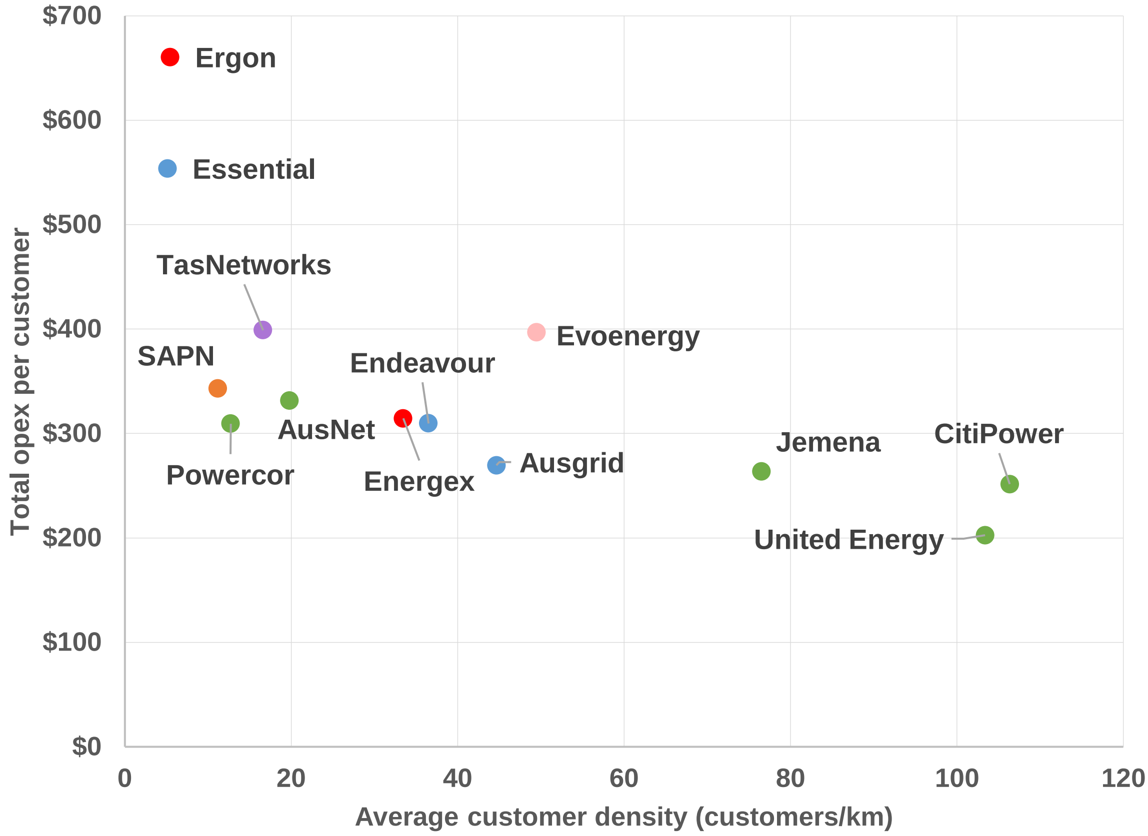
Source: AER, *2024 Annual Benchmarking Report – electricity distribution network service providers*, November 2024; AER analysis.

Partial performance indicators

We have also examined the relative opex performance of Energex over the 5-year period (2019–2023) 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).

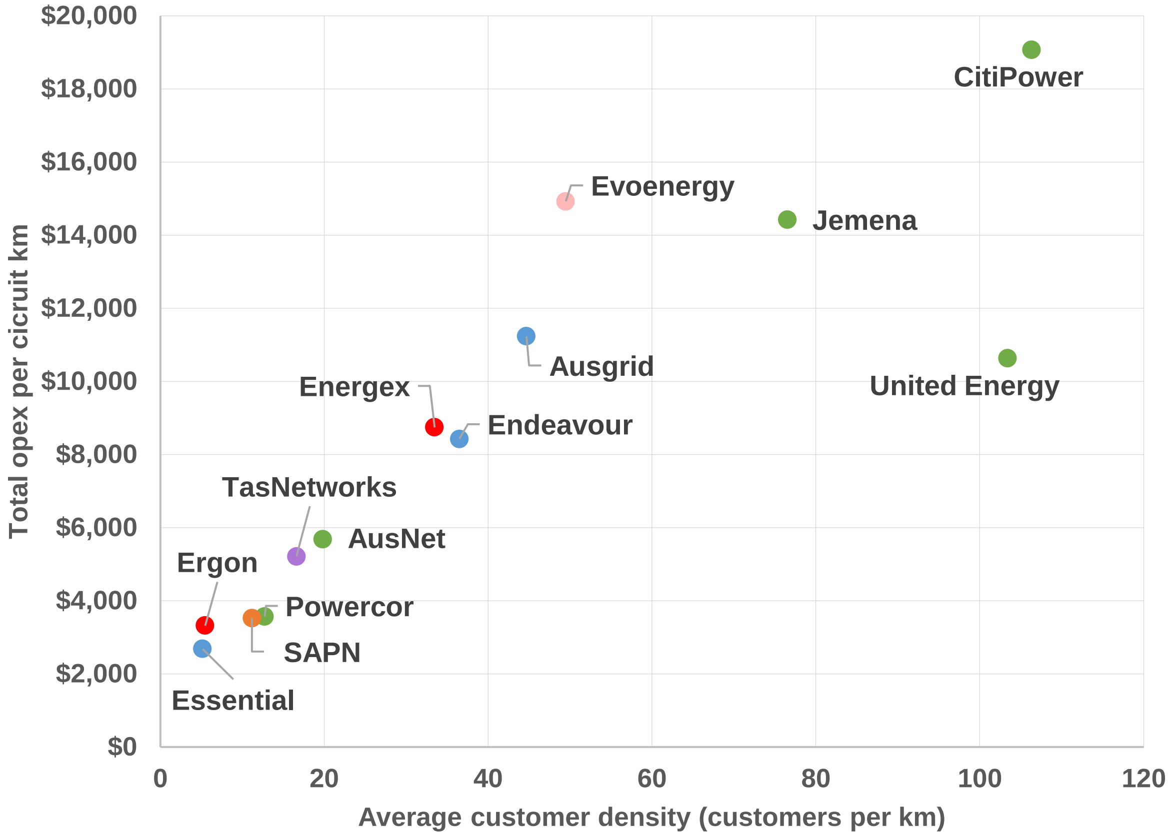
In terms of total opex, both on a per customer and per circuit length kilometre basis, Energex benchmarks relatively closely with its most similar comparator on a customer density basis (Endeavour Energy). This is shown in Figure 6.7 and Figure 6.8 respectively.

Figure 6.7 Total opex per customer against customer density (($2024–25), 2019–23 average)



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

Figure 6.8 Total opex per kilometre of circuit length against customer density (($2024–25), 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 Energex's base year opex

Given the evidence outlined above about the possible inefficiency of Energex'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 Energex's 2022–23 base year opex. We then determine whether there is an efficiency 'gap', and if so, the magnitude of this 'gap'.[54]

We have outlined our approach in further detail in past decisions.[55] We have applied the same OEF adjustments used in our draft decision[56], and subsequently accepted by Energex.

54 Our final decision applies the same approach as the draft decision in assessing the efficiency of Energex's base year opex.

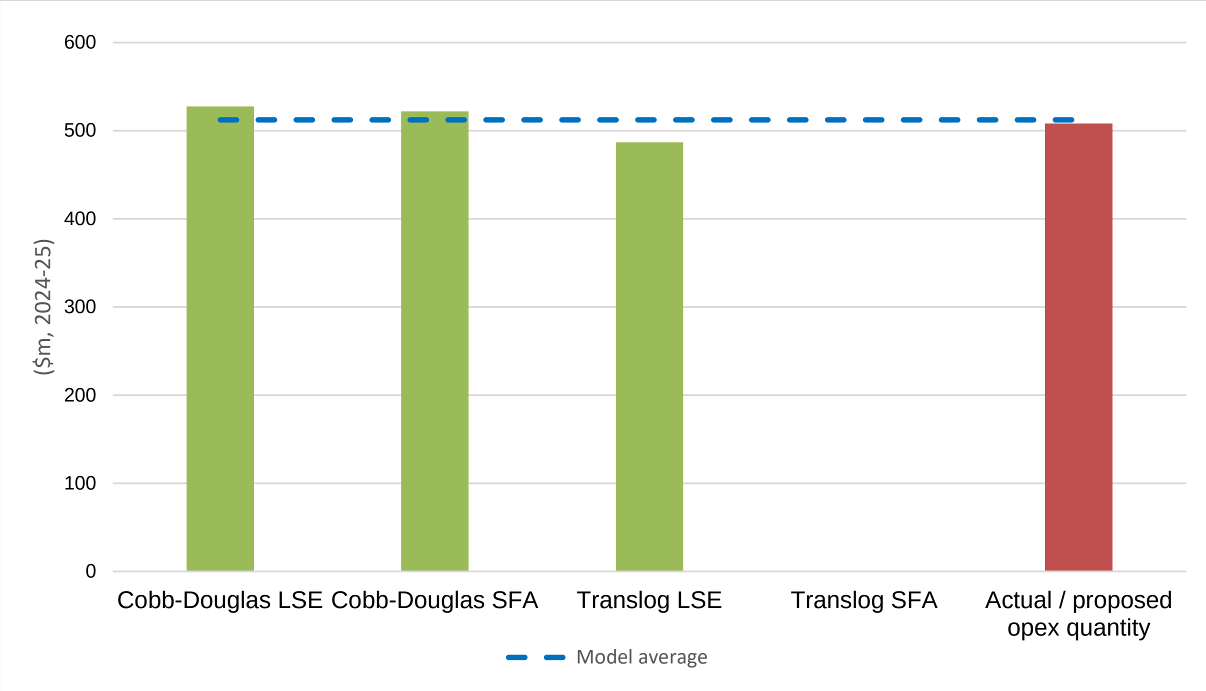
55 AER, Final Decision, *Jemena distribution determination 2021–26 – Attachment 6 – operating expenditure*, April 2021, p. 25.

56 AER, Draft Decision, *Energex distribution determination 2025–30 – Attachment 6 – operating expenditure*, September 2024, pp. 23–25.

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.

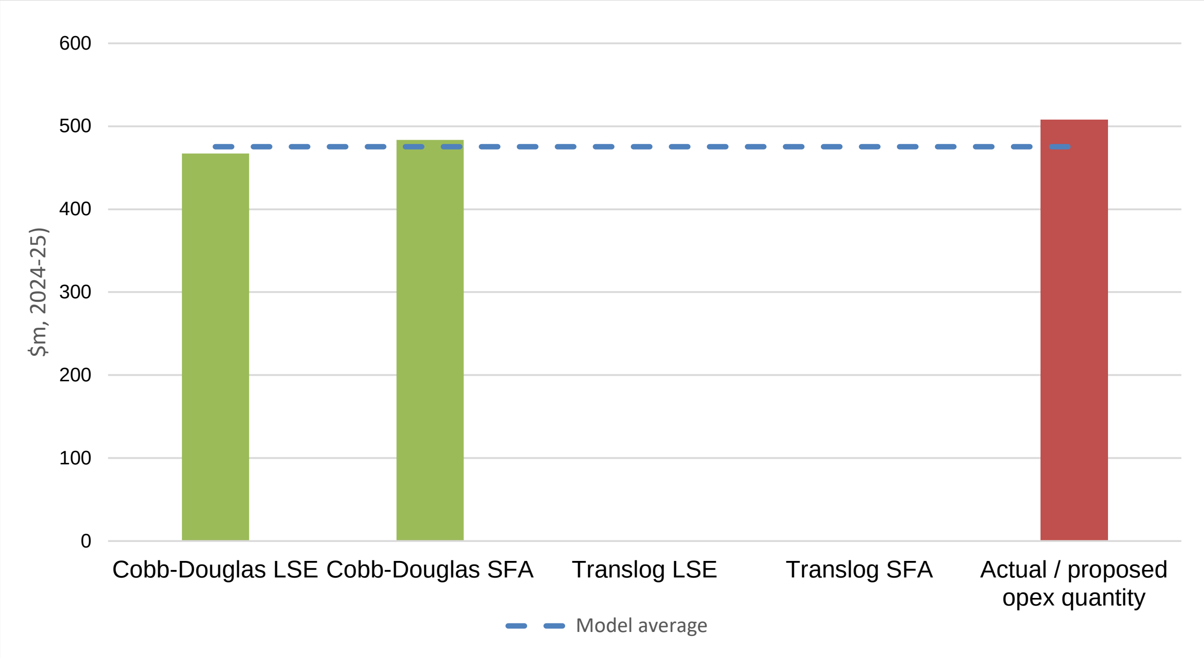
From these figures, we see that Energex's 2022–23 base year opex is on the borderline of efficiency and inefficiency, being below our estimated efficient base year opex based on the long period measure and above the benchmark on the short period measure.

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.

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 on balance Energex's base year opex is on the borderline in terms of efficiency / inefficiency. Given this, and in these particular circumstances, we have relied on Energex's revealed costs and used its 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 Energex's revealed costs to forecast opex for the next period, we are also applying the EBSS penalties Energex has accrued in the current period, and applying the EBSS in the next regulatory period. Attachment 8 outlines our EBSS decision in more detail. We note that in the context of this final decision, relying on Energex's revealed costs (i.e. using its actual 2022–23 opex to forecast opex and applying its EBSS penalties as incurred) results in it receiving lower combined allowed revenues compared to the outcome of applying a small efficiency adjustment using our standard benchmarking approach (i.e. making an efficiency adjustment to base opex, including transition costs to enable transition to the lower efficient opex level, and not apply EBSS penalties).

Submissions received on our draft decision and Energex's revised proposal[57] from Energy Queensland's Reset Reference Group (RRG) and the CCP30 were critical of inclusion of transition costs, and Energex's revised proposal that we not apply its EBSS penalties or the scheme in the next regulatory period.[58] The RRG noted that it was not convinced that the

57 Which relied on Energex's estimated 2023–24 opex for the base year.

58 CCP30, *Submission on Energex's revised proposal and draft decision 2025–30,* January 2025, pp. 19–23; RRG, *Submission on Energex's revised proposal and draft decision 2025–30,* January 2025, pp. 35 and 38.

AER's standard approach to give transition costs when making an efficiency adjustment to base opex should be applied for Energex. 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 conditional on the businesses achieving efficiencies.[59] The CCP also submitted that transition costs are not warranted unless Energex has a clear and well-articulated plan to transition to an efficient level of costs in the next regulatory period.[60] CCP30 noted that Energex 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 Energex should bear the full penalties under our regulatory framework designed to encourage efficient delivery of distribution services.[61]

Having regard to the above, we consider that in the specific circumstances for Energex in this reset, relying on Energex's revealed costs is consistent with our requirements under the NER and results in outcome that best promotes the long-term interest of consumers.

6.4.2 Adjustments to base year opex

Energex's revised proposal included $46.9 million in base year adjustments, or $234.6 million over the 2025–30 period.[62] These are largely for the same adjustments Energex proposed in its initial proposal, and we included in our draft decision,[63] with Energex 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.[64]

We have adjusted our alternative estimate of opex in the base year by –$30.5 million, or –$152.6 million over 5 years to:

- subtract $14.0 million for the Electrical Safety Office levy. This decreases our alternative estimate of total opex by $69.9 million over 5 years
- subtract $3.5 million for the reclassification of ongoing lease costs as capex in the 2025–30 period.[65] This decreases our alternative estimate of total opex by $17.7 million over 5 years.
- subtract $8.2 million for actual debt raising costs. This decreased our alternative estimate of total opex by $40.8 million over 5 years.
- subtract $4.8 million for the change in opex between 2022–23 and 2024–25. This decreased our alternative estimate by $24.1 million over 5 years. Our final year

59 RRG, *Submission on the Australian Energy Regulator's Draft Decision and Energex's Revised Regulatory Proposal for 2025–30*, January 2025, pages 33-35.

60 CCP30, *Submission on Energex's revised proposal and draft decision 2025–30,* January 2025, p. 19.

61 CCP30, *Submission on Energex's revised proposal and draft decision 2025–30,* January 2025, p. 21.

62 Energex, *6.01 – Model – SCS Opex model*, November 2024.

63 AER, *Draft decision, Attachment 6 – Operating expenditure – Energex – 2025–30 Distribution revenue proposal*, September 2024, pp. 31–33.

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

65 Energex, *Response to information request, IR#058 – Output growth forecasts and base year adjustments,* 19 December 2024, p. 3.

increment is materially larger than Energex's as our forecasts includes one additional year.

The reasons for the difference between our total adjustment and that of Energex is that we have used Energex's 2022–23 actual expenditure to calculate the adjustments, as opposed to 2023–24 in Energex'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.

6.4.3 Rate of change

We have included a rate of change that increases opex, on average, by 0.8% each year in our alternative estimate. This contributed $53.4 million to overall opex in our alternative estimate. This compares to Energex's average annual rate of change of 0.6%, contributing $42.6 million to its opex forecast.

Energex's revised proposal made some updates to its trend inputs to reflect actual data for 2023–24. Energex 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 Energex's revised productivity forecast and ratcheted maximum demand forecasts. The overall updates included:

- **price growth** – Energex 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.[66] We have further updated our WPI forecast with the latest Deloitte Access Economic forecasts.[67]
- **output growth** – Energex updated customer numbers, circuit length and maximum demand to reflect actual data for 2023–24, and provided updated forecasts, but did not ratchet the maximum demand forecasts.[68] Energex confirmed in a response to an information request that this was an oversight and accepted our standard ratchetting approach.[69] We accepted Energex's updated customer numbers and circuit length forecasts. We did not accept the maximum demand forecasts and have substituted alternative values into our opex forecast. This is explained further below.
- **Productivity growth** – Energex included a 1% productivity forecast. We have used 0.5% productivity growth forecast, consistent with our standard approach.

For the output weights, Energex stated that it used values based on our preliminary Quantonomics Report.[70] We have updated the output weights consistent with our 2024 Annual Benchmarking Report.

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

---

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

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

68 Energex, *2025–30 Revised regulatory* proposal, November 2024, p. 74.

69 Energex, response *to AER information request IR#*065, 28 January.

70 Energex, *2025–30 Revised regulatory* proposal, November 2024, p. 74.

Table 6.3 Forecast annual rate of change in opex, %

	2025–26	2026–27	2027–28	2028–29	2029–30
Energex's proposal					
Price growth	0.7	0.5	0.5	0.6	0.7
Output growth	1.1	0.9	0.9	1.0	0.9
Productivity growth	1.0	1.0	1.0	1.0	1.0
Rate of change	**0.8**	**0.5**	**0.4**	**0.6**	**0.6**
AER alternative estimate					
Price growth	0.7	0.6	0.5	0.6	0.7
Output growth	0.6	0.6	0.6	0.6	0.9
Productivity growth	0.5	0.5	0.5	0.5	0.5
Rate of change	**0.8**	**0.8**	**0.6**	**0.7**	**1.1**
Difference	**0.0**	**0.3**	**0.2**	**0.1**	**0.5**

Source: Energex, *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, Energex informed us that its updated maximum demand forecasts for the 2025–30 period were based on a “native load” definition of the maximum demand,[71] which includes an estimate of the potential load that may be met by major embedded generators.[72] Our standard approach to measuring maximum demand for the purposes of forecasting total opex is to use a ‘network load’ definition,[73] 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. Energex 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

71 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.

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.

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

by major embedded generation).[74] 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 Energex 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.

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.[75]

6.4.4.1 Smart meter data acquisition and analysis step change

We have included $4.7 million for smart meter data and analysis in our alternative estimate of forecast opex for the final decision. This is $11.0 million lower than Energex's revised proposal of $15.7 million, and reflects that we are not satisfied that all proposed components of this step change reflect prudent and efficient expenditure.

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

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
Energex's revised proposal	3.4	2.6	2.9	3.3	3.6	15.7
AER final decision	2.1	0.6	0.6	0.6	0.7	4.7
Difference	**–1.2**	**–2.0**	**–2.3**	**–2.6**	**–2.9**	**–11.0**

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

Energex's initial proposal included $14.6 for the acquisition and analysis of smart meter data to increase its low voltage network visibility.[76] We discuss this step change, our assessment and the reasons for the inclusion of a lower amount of $3.4 million, in further detail in our draft decision.[77]

For its revised proposal, Energex included a higher amount of $15.7 million, or $1.0 million higher than its initial proposal, and $12.3 million higher than our draft decision. Energex 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,

---

74 Energex, *Response to AER information request, IR#074 – Maximum demand forecasts*, 18 February 2025, pp.1–2.

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

76 Energex, *2025–30 Regulatory Proposal,* January 2024, pp. 137–138.

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

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.[78]

We assessed the information provided in Energex'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 Energex has not provided sufficient evidence to support a change to our draft decision. We consider that although Energex 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 Energex, the likely incremental benefits gained from real-time data are not significant enough to outweigh the additional costs, compared to the free daily data.[79] Overall, the AEMC also considers that extending access to distributors for real-time data, additional to providing access the daily data, is not in the long-term interest of consumers.[80]

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. Option 1 is consistent with our draft decision, but additionally also includes costs to purchase one additional year's data.

In terms of reliability benefits, Energex 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 Energex 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). However, through an information request, Energex clarified that it currently does not have a breakdown of the times for each individual response component.[81] Based on this, we are not satisfied that an appropriate method was used to calculate the likely reduction in response time achievable through faster outage notification.

In terms of the safety benefits, we consider Energex'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 Energex overestimated the capacity to identify 60% of faults using smart meter data and the ability to identify more faults using live data.[82] That is, the information provided suggests that daily data will improve the potential

---

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

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

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

81 Energex, R*esponse to AER information request IR#067 – Smart meter data step change, Q11–Q12*, 29 January 2025.

82 Energex, *6.04A – Business case – Smart meter data* acquisition, November 2024, p. 6.

safety outcomes, without clarifying whether, or how, higher frequency data provision may impact this outcome.

Considering the above, we have included a lower amount of $4.7 million for the smart meter data step change. Consistent with our draft decision, this cost aligns to Energex's Option 1 or base case scenario, and reflects the likely prudent and efficient level of costs needed to uplift Energex's data management and analytics capabilities to process power quality data that will be made available to distribution businesses at no charge. Option 1 also includes costs to purchase smart meter data for 1 year.

6.4.5 Category specific forecasts

Energex'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 $39.2 million in our alternative estimate, or $0.2 million higher than the amounts proposed by Energex.

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

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
Energex's revised proposal	7.8	7.8	7.8	7.8	7.8	39.0
AER draft decision	7.8	7.8	7.9	7.8	7.8	39.2
Difference	0.0	0.0	0.0	0.0	0.0	0.2

Source: Energex, *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.

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