Draft Decision Evoenergy

Regulatory proposal 2024 to 2029

(1 July 2024 to 30 June 2029)

Attachment 6
Operating expenditure

September 2023

AUSTRALIAN ENERGY REGULATOR

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AER reference: AER212496

Amendment record

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6 Operating expenditure

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

This attachment outlines our assessment of Evoenergy's proposed opex forecast for the 2024–29 regulatory control period.

6.1 Draft decision

Our draft decision is not to accept Evoenergy's proposed opex forecast of $390.1 million ($2023–24) for the 2024–29 regulatory control period.[1] This is because we are not satisfied that it reasonably reflects the opex criteria, having regard to the opex factors.[2]

Our draft decision is to include our alternative estimate of total opex forecast of $336.5 million ($2023–24) for Evoenergy. This draft decision is:

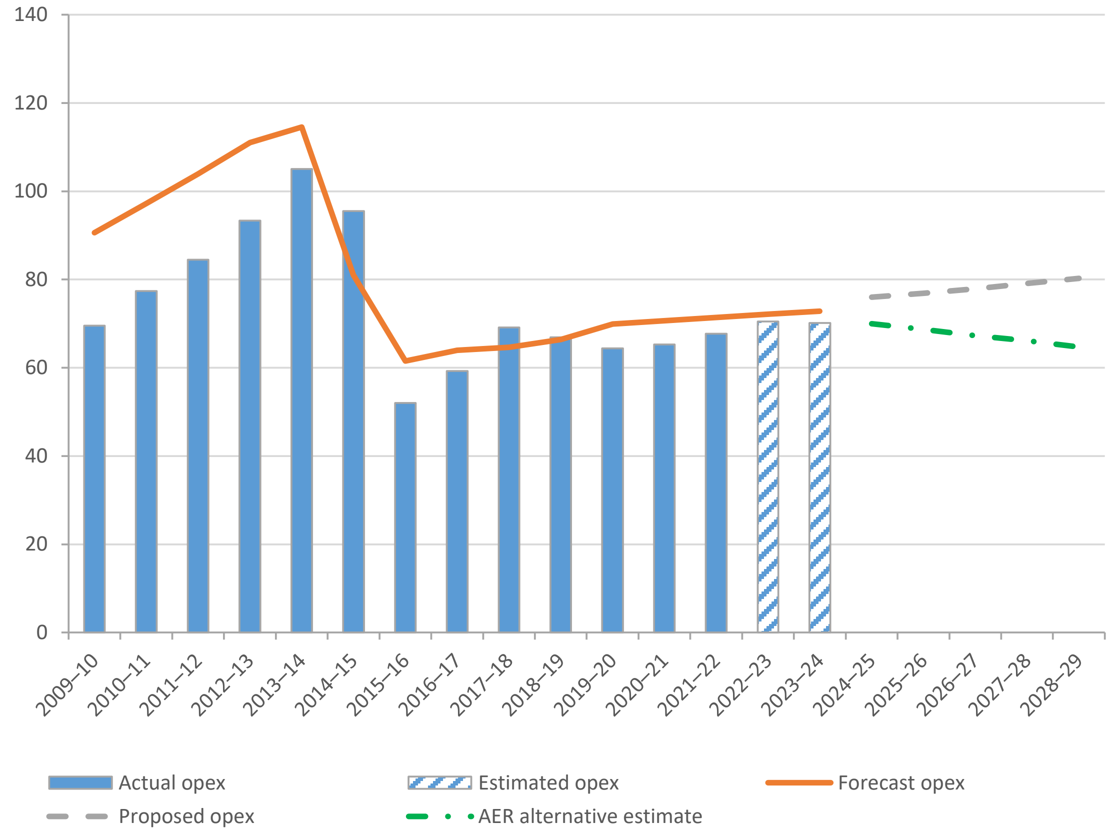
- $53.6 million ($2023–24) (or 13.7%) lower than Evoenergy's proposal for the 2024–29 regulatory control period.
- $1.6 million ($2023–24) (or 0.5%) lower than Evoenergy's actual (and estimated) opex in the 2019–24 regulatory control period.
- $20.4 million ($2023–24) (or 5.7%) lower than the opex forecast we approved in our final decision for the 2019–24 regulatory control period.

Figure 6.1 compares the opex forecast we approve in this draft decision to Evoenergy's proposal, the forecasts we approved for the last two regulatory control periods from 2009–10 to 2023–24, and Evoenergy's actual and estimated opex across that period.

1 Evoenergy, *SCS opex model*, 31 January 2023.

2 This is the assessment we must make of proposed opex under cl. 6.5.6(c) and cl. 6.5.6(e) of the NER.

Figure 6.1 Historical and forecast opex ($2023–24)



Source: Evoenergy, *Economic benchmarking – Regulatory Information Notice response 2009–22*; AER, *Final decision PTRM 2009–14*; AER, *Final decision 2014–19 PTRM*; AER, *Final decision 2019–24 PTRM* and *Opex model*; Evoenergy, *2024–29 Regulatory proposal*, January 2023; AER analysis.

Table 6.1 sets out Evoenergy's opex proposal, our alternative estimate for the draft decision and the differences between these forecasts.

Table 6.1 Comparison of Evoenergy's proposal and our draft decision on opex ($million, 2023–24)

	Evoenergy's initial proposal	Our alternative estimate	Difference
Based on reported opex in 2021–22[3]	**337.2**	**332.1**	**–5.1 (–1.3%)**
Efficiency adjustment	**–**	**–51.6**	**–51.6 (–13.2%)**
Transition costs	**–**	**20.9**	**20.9 (5.3%)**
Base year adjustments[4]	**–2.9**	**–2.9**	**–**
2021-22 to 2023-24 increment	**7.2**	**-2.1**	**–9.3 (–2.4%)**
Remove category specific forecasts	**–**	**–**	**–**
Output growth	14.1	6.6	–7.5 (–1.9%)

3 After removal of Demand Management Innovation Allowance (DMIA) costs and movements in provisions, as discussed further in section 6.2 and section 6.4.1.3.

4 This is the removal of administrative costs of the large feed in tariff (LFiT), as discussed further in section 6.2 and section 6.4.

	Evoenergy's initial proposal	Our alternative estimate	Difference
Price growth	5.3	5.1	–0.3 (–0.1%)
Productivity growth	–5.1	–3.8	1.4 (0.4%)
Total trend	**14.3**	**7.9**	**–6.4 (–1.6%)**
Insurance	5.0	5.0	0.0 (0.0%)
Cyber Security	14.6	14.6	–
DER Integration	11.6	9.9	–1.8 (–0.5%)
Total step changes	**31.2**	**29.4**	**–1.7 (–0.4%)**
Debt raising costs	3.2	2.9	–0.3 (–0.1%)
Total category specific forecasts	**–**	**–**	**–**
Total	**390.1**	**336.5**	**–53.6 (–13.7%)**

Source: Evoenergy, *Attachment 2 Operating Expenditure*, January 2023, p. 31; 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.

Our lower alternative total opex forecast is primarily due to our findings that Evoenergy's 2021–22 base year opex is materially inefficient, as indicated by our benchmarking results and other analysis. As a result, our alternative estimate does not rely on actual or 'revealed' opex in the 2021–22 base year. Instead, we have made an efficiency adjustment to actual base year opex to reflect our view of an efficient level of recurrent opex.

Based on our benchmarking analysis, the efficiency 'gap' between estimated efficient base year opex and Evoenergy's actual base year opex is 15.7%. Straight application of this as an efficiency adjustment would be $10.3 million ($2023–24) per year, or a total $51.6 million ($2023–24) adjustment over the 2024–29 regulatory control period. However, we have incorporated a linear glide path to transition Evoenergy to the more efficient opex level over the 2024–29 regulatory control period. This recognises it will take time and involve costs to realise opex reductions. In practice, this results in a total efficiency adjustment over the 2024–29 regulatory control period of $30.8 million ($2023–24), reflecting an opex efficiency adjustment, as a percentage of our alternative estimate of base year opex after base adjustments, of 9.4%.

The other main drivers of our lower alternative estimate of total opex are:

- a lower final year increment (–$9.3 million ($2023–24)) as we no longer apply the standard final year equation to estimate final year opex where we make an efficiency adjustment to base opex
- lower expected output growth (–$7.5 million ($2023–24)), associated with lower forecasts of ratcheted maximum demand
- lower step change costs ($–1.7 million ($2023–24)) due to a lower estimate of efficient costs for the consumer energy resources integration step change.

Table 6.2 provides our assessment of the extent to which Evoenergy has met the Better Resets Handbook (the Handbook) expectations in relation to forecast opex.[5]

Table 6.2 Better Resets Handbook Expectations

Opex expectations	Comment
1. Opex forecasting approach	Evoenergy applied our standard base-step-trend forecasting approach to forecast opex for the 2024–29 period. Evoenergy's opex forecast is consistent with the opex forecast used in the EBSS.
2. Base opex	Evoenergy used 2021–22 as the base year, where audited actual opex for this year is available, as per Handbook expectations. We consider that Evoenergy's opex in the base year (2021–22) is materially inefficient. We have made an efficiency adjustment to actual base year opex.
3. Trend	Evoenergy applied our standard approach to forecast the opex rate of change or trend growth forecast for price, output and productivity growth, with the minor exception in price growth of not adopting our standard approach of averaging the respective consultants' Wage Price Index (WPI) forecasts.
4. Step changes	Evoenergy proposed three step changes, representing a material amount (8.0%) of total forecast opex. We have undertaken a targeted review of two of the proposed step changes: the Security of Critical Infrastructure step change ($14.6 million) and the consumer energy resource (CER) integration step change ($11.6 million).
5. Category specific forecasts	Evoenergy has not applied our standard approach to forecast debt raising costs. We have substituted our alternative estimate of forecast debt raising costs.
6. Genuine consumer engagement on operating expenditure forecasts	Overall, it was not clear the extent to which Evoenergy had demonstrated a genuine approach to consumer engagement in relation to its opex proposal, as observed by the AER's Consumer Challenge Panel (CCP26).

6.2 Evoenergy's proposal

Evoenergy's proposal applied a "base-step-trend" approach to forecast opex for the 2024–29 regulatory control period, largely consistent with our standard approach.[6]

In applying our base-step-trend approach to forecast opex, Evoenergy:

- used reported opex[7] in 2021–22 as the base from which to forecast ($67.4 million ($2023–24) or $337.2 million ($2023–24) over the next regulatory control period)
- adjusted its total base forecast opex by subtracting $2.9 million ($2023–24) for the administration of the large-feed-in tariff scheme

5 AER, *Better Rests Handbook – Towards consumer-centric network proposals*, December 2021, pp. 24–29.

6 Evoenergy, *Attachment 2 Operating Expenditure*, January 2023, p. 15.

7 After removal of Demand Management Innovation Allowance (DMIA) costs and movements in provisions, as discussed further in section 6.4.1.3.

- added an estimate of the difference between the base year opex and the opex it will incur in the final year of the current regulatory control period using our final-year formula, increasing opex by $7.2 million ($2023–24)
- applied its overall rate of change forecast to its final year adjusted opex estimate, increasing opex by $14.3 million ($2023-24). This included:
  - output growth ($14.1 million ($2023–24))
  - price growth ($5.3 million ($2023–24))
  - productivity growth (–$5.1 million ($2023–24))
- added 3 step changes totalling $31.2 million ($2023–24) for:
  - insurance ($5.0 million ($2023–24))
  - cyber security ($14.6 million ($2023–24)), and
  - CER integration ($11.6 million ($2023–24))
- added $3.2 million ($2023–24) of debt raising costs to arrive at a total opex forecast of $390.1 million ($2023–24) over the 2024–29 regulatory control period.

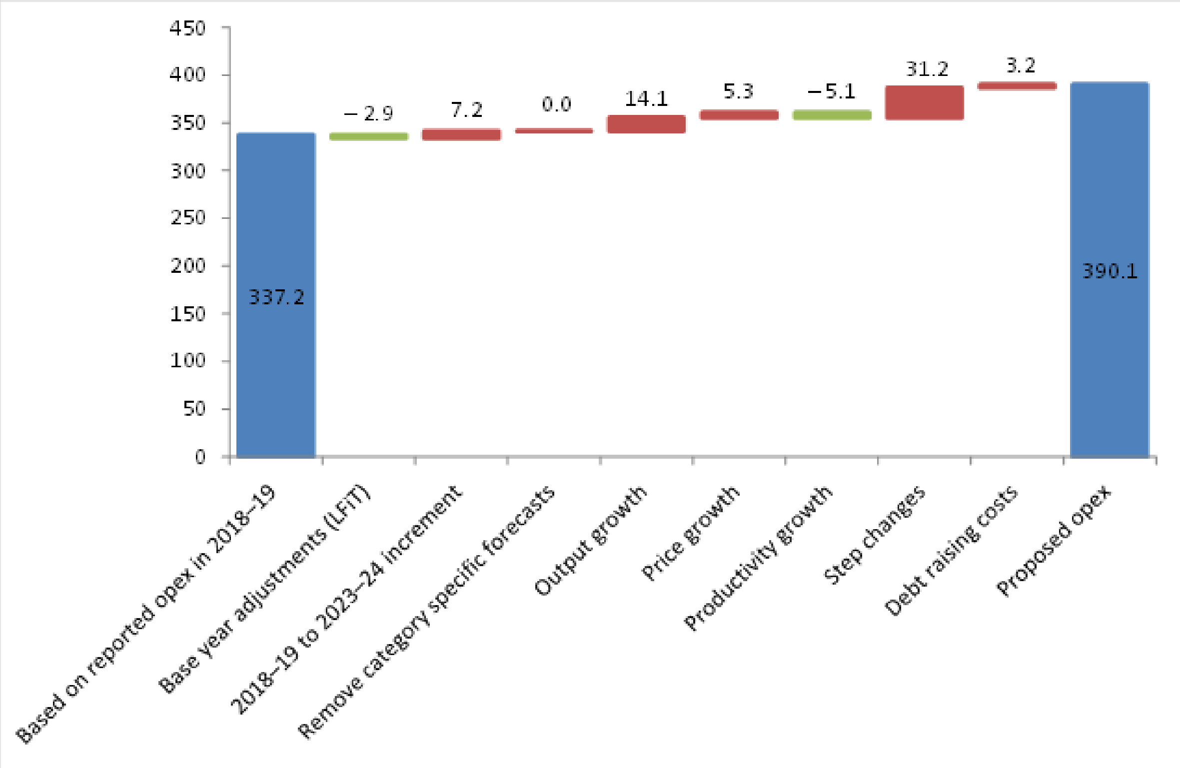
Table 6.3 Evoenergy's proposed opex for the 2024–29 period ($million, 2023–24)

	2024–25	2025–26	2026–27	2027–28	2028–29	Total
Total Opex, excluding debt raising costs	75.3	76.2	77.2	78.4	79.6	386.8
Debt raising costs	0.6	0.6	0.6	0.6	0.7	3.2
Total Opex, including debt raising costs	**76.0**	**76.9**	**77.9**	**79.1**	**80.3**	**390.1**

Source: Evoenergy, *Attachment 2 – Operating Expenditure, January 2023*, p. 32; AER analysis.
Note: Numbers may not add up to total due to rounding.

Figure 6.2 shows the different components that make up Evoenergy's opex forecast for the 2024–29 regulatory control period.

Figure 6.2 Evoenergy's proposed opex ($million, 2023–24)



Source: AER analysis

Evoenergy's total opex forecast of $390.1 million ($2023-24) for the 2024–29 regulatory control period is $33.2 million ($2023–24), or 9.3%, higher than the amount we determined in our 2019–24 determination, and $53.3 million ($2023–24), or 15.8%, higher than its actual and estimated spend over the 2019–24 regulatory control period.

6.2.1 Stakeholder views

We received 7 submissions on Evoenergy's proposal which discussed opex issues.

We have taken these submissions into account in developing the positions set out in this draft decision. Table 6.4 summarises the stakeholder issues raised in the submissions in relation to opex.

Table 6.4 Submissions on Evoenergy's 2024–29 opex proposal

Stakeholder(s)	Issue	Description
Origin EnergyAustralia ACTCOSS Conservation Council	Base opex	• Origin submitted that it is important for the AER to confirm that network underspend in the current regulatory control period is not offset by future opex increases, such as base year adjustments and step changes.[8] • EnergyAustralia submitted that expenditure based on forecasts should be well substantiated to ensure that it cannot be delayed until future periods when inflationary impacts are reduced.[9]

8 Origin Energy, *Submission - 2024-29 Electricity Determination - NSW and ACT*, May 2023, pp. 3–5.

9 EnergyAustralia, *Submission - 2024-29 Electricity Determination - NSW and ACT*, May 2023. p. 1.

Stakeholder(s)	Issue	Description
		• Overall, ACTCOSS submitted that the basis for Evoenergy's proposed opex seems reasonable. Evoenergy have sought to balance efficiency and affordability with reliability and customer service.[10] • The Conservation Council submitted that forecast expenditure for "emergency response" has been increased for 2024-29 compared to actual expenditure in the previous and current periods, (Attachment 2, Figure 4) taking into account the potential for more frequent and larger-scale operational responses to extreme weather events caused by the warming climate, such as bushfires and thunderstorms. The Council submitted that this is prudent.[11]
Origin Conservation Council	Base adjustments	• Origin Energy was concerned that base year adjustments make it difficult to assess the efficiency of the base year.[12] • The Conservation Council submitted that the past can no longer predict the future, but year-to-year the adjustments seem reasonable.[13]
Origin Red Energy and Lumo Conservation Council CCP26	Step changes	• Origin Energy submitted that distribution network service providers' proposed step changes represent significant increases in opex, these should be rigorously examined by the AER to determine if they are appropriate.[14] • Red Energy and Lumo submitted that the AER should conduct a forensic examination of the new and emerging areas of capital and operational expenditure in the regulatory proposals across resilience, CER integration and innovation expenditure. There is concern that the proposed expenditures are excessive and may not deliver the benefits that they claim. Furthermore, competitive markets will deliver more efficient and innovative customer focused solutions than regulated monopolies. As such, the AER should undertake this examination regardless of whether these expenditures have been developed jointly with consumers.[15] • The Conservation Council submitted that a step change for distributed energy resource integration seems necessary for providing a responsive and efficient network. Evoenergy must ensure that low-income households are not disadvantaged.[16] • CER integration – CCP26 noted consumers were generally supportive of CER Integration expenditure, not because they understood what was being proposed, but because they thought it was aligned with the net zero policies of the ACT Government which are well supported by most ACT residents, from its observations.[17] • Insurance – CCP26 did not observe discussions about Board risk appetite, risk trade-offs, or other options for managing risk such as cost pass throughs which would usually form the background to an informed discussion on risk options.[18]

10 ACTCOSS, *Submission - 2024-29 Electricity Determination - Evoenergy*, May 2023, p. 15.

11 Conservation Council ACT Region, *Submission - 2024-29 Electricity Determination - Evoenergy*, May 2023, p. 7.

12 Origin Energy, *Submission - 2024-29 Electricity Determination - NSW and ACT*, May 2023, pp. 1–4.

13 Conservation Council ACT Region, *Submission - 2024-29 Electricity Determination - Evoenergy*, May 2023, p. 8.

14 Origin Energy, *Submission 2024–29 Electricity Determination – NSW and ACT*, May 2023, p. 4.

15 Red Energy and Lumo, *Submission - 2024-29 Electricity Determination - NSW*, May 2023, p. 2.

16 Conservation Council ACT Region, *Submission - 2024-29 Electricity Determination - Evoenergy*, May 2023, p. 7.

17 CCP26, *Advice to AER - 2024-29 Electricity Determination - Evoenergy*, May 2023, p. 15.

18 CCP26, *Advice to AER - 2024-29 Electricity Determination - Evoenergy*, May 2023, p. 16.

Stakeholder(s)	Issue	Description
		• Security of critical infrastructure; – The Conservation Council noted this step change seems prudent given the recent cyber attacks on major Australian companies.[19] – CCP26 does not believe this step change was fully understood by Panel members, and consider that their support is qualified.[20] • CCP26 noted that cyber security and insurance step change proposals are similar to cost increases being sought by other network providers. This suggests that the proposed increases are likely to be comparable with peers. CCP26 will leave it to the AER to determine whether the expenditures proposed are both prudent and efficient.[21]
Conservation Council CCP26	Consumer engagement	• The Conservation Council stated that it is clear that Evoenergy has considered consumer concerns, if not necessarily satisfying them all.[22] • CCP26 did not observe any deep engagement on or challenge of proposed opex. Given current cost of living concerns for many customers, and the strong affordability theme that permeated Evoenergy's engagement, this is a concerning gap in Evoenergy's engagement processes.[23]

Source: Submissions to Evoenergy's regulatory proposal

6.3 Assessment approach

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'.[24] In doing so, we must have regard to the opex factors specified in the National Electricity Rules (NER).[25]

The *Expenditure forecast assessment guideline* (the Guideline), together with an explanatory statement, sets out our assessment approach in detail.[26] 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.[27]

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.[28] We compare our alternative estimate with the business's total

19 Conservation Council ACT Region, *Submission - 2024-29 Electricity Determination - Evoenergy*, May 2023, p. 7.

20 CCP26, *Advice to AER - 2024-29 Electricity Determination - Evoenergy*, May 2023, p. 15.

21 CCP26, *Advice to AER - 2024-29 Electricity Determination - Evoenergy*, May 2023, p. 16.

22 Conservation Council ACT Region, *Submission - 2024-29 Electricity Determination - Evoenergy*, May 2023, p. 7.

23 CCP26, *Advice to AER - 2024-29 Electricity Determination - Evoenergy*, May 2023, p. 14.

24 NER, cl. 6.5.6(c).

25 NER, cl. 6.5.6(e).

26 AER, *Expenditure forecast assessment guideline for electricity distribution*, August 2022; AER, *Expenditure forecast assessment guideline - Explanatory statement*, November 2013.

27 NER, cl. 6.2.8(c).

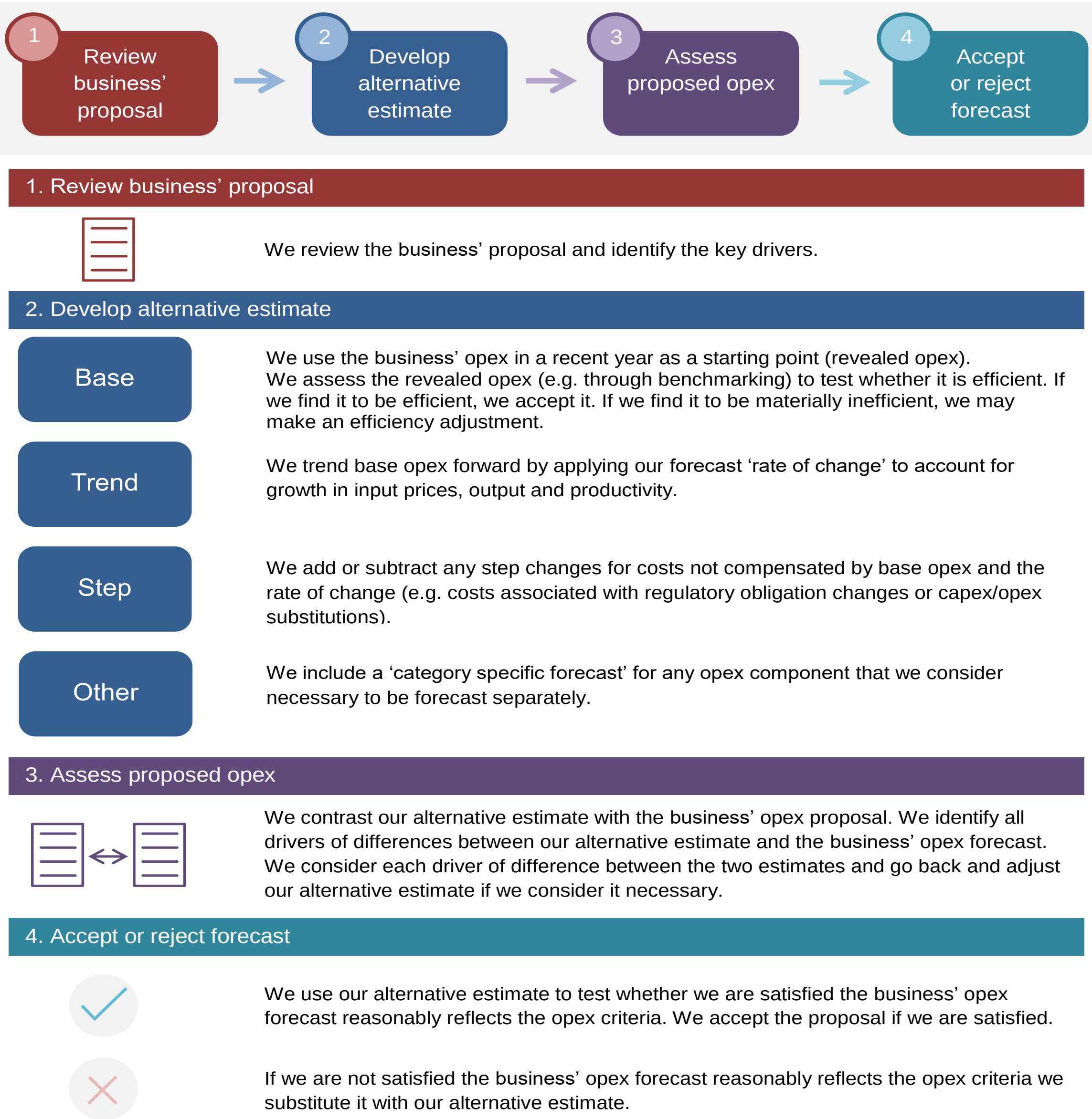
28 A 'top-down' approach forecasts total opex at an aggregate level, rather than forecasting individual projects or categories to build a total opex forecast from the 'bottom up.'

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 must accept the forecast.[29] If we are not satisfied, we must substitute the business's forecast with our alternative estimate that we are satisfied reasonably reflects the opex criteria.[30]

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 must specify interrelationships between opex and the other building block components of our decision, and how we have taken them into consideration.[31]

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

Figure 6.3 Our opex assessment approach



29 NER, cl. 6.5.6(c).

30 NER, cl. 6.5.6(d).

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

6.3.1 Interrelationships

In assessing Evoenergy'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 estimate of opex for 2023–24 (the final year of the current regulatory control period) that we use to forecast opex should be the same as the level of opex used to calculate EBSS carryover amounts. 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 2019–23 regulatory control period, which provided Evoenergy 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 Evoenergy's engagement with consumers and stakeholders in developing its proposal and any feedback we have had.

6.4 Reasons for draft decision

We do not accept Evoenergy's proposed opex forecast of $390.1 million ($2023–24), including debt raising costs, for the 2024–29 regulatory control period, because we are not satisfied that it reflects the opex criteria, having regard to the opex factors.

Our draft decision is to include our alternative total opex forecast of $336.5 million ($2023–24). This is $53.3 million, or 13.7%, lower than Evoenergy's forecast. We are satisfied our alternative estimate of total forecast opex for DNSP reasonably reflects the opex criteria.

Table 6.1 sets out Evoenergy's proposal, our alternative estimate that is the basis for the draft decision, and the difference between our draft decision and the proposal.

The main drivers for the differences are also set out in Section 6.1 and we discuss the components of our alternative estimate, and our assessment of Evoenergy's proposal, below. 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 Evoenergy would need for the safe and reliable provision of electricity services over the 2024–29 regulatory control period.

Evoenergy proposed a base year of 2021–22 and base year opex of $67.4 million ($2023–24) or $337.2 million ($2023–24) over the next regulatory control period. It considered that the opex in this year represents the efficient level of sustainable costs to provided standard control services.[32]

In support of this Evoenergy implemented the AER's benchmarking approach to assess the efficiency of its opex in the proposed base year of 2021–22. As a part of this assessment Evoenergy:

- corrected its historical ratcheted maximum demand (RMD) data to ensure consistency over time and recognise utilisation of its dual function assets
- applied the same operating environment factors (OEFs) as the AER applied in the 2019–24 reset decision but updated the costs associated with the backyard reticulation OEF and proposed a new workers' compensation OEF
- accounted for step changes in its vegetation management opex in the base year when estimating the efficient level of opex using the benchmarking results.

Evoenergy noted that this resulted in an estimate of efficient base year opex that was 8.0% lower than its actual base year opex. However, it noted that this did not take account of capitalisation differences between DNSPs (on which the AER was still consulting at the time of Evoenergy's proposal) and for the many shortcomings and limitations associated with the AER's benchmarking approach. It considered that when these are taken into account the AER should not conclude that Evoenergy's actual opex in the base year is materially inefficient.[33]

We do not agree with this conclusion and consider Evoenergy's opex in the base year is a materially inefficient basis for a forecast, as indicated by our benchmarking results and other analysis. As a result, our alternative estimate does not rely on actual or 'revealed' opex in the 2021–22 base year. Instead, we have made an efficiency adjustment to actual base year opex to reflect our view of an efficient level of recurrent opex. Based on our benchmarking analysis, the efficiency 'gap' between estimated efficient base year opex and actual base year opex is 15.7%. Straight application of this as an efficiency adjustment would be $10.3 million ($2023–24) per year, or a total $51.6 million ($2023–24) adjustment over the 2024–29 regulatory control period. However, we have incorporated a linear glide path to transition Evoenergy to the more efficient opex level over the 2024–29 regulatory control period. This is a pragmatic approach that recognises it will take time and involve costs for management to implement the required programs to realise opex reductions. In practice, this means a total efficiency adjustment over the 2024–29 regulatory control period of $30.8 million ($2023–24), reflecting an opex efficiency adjustment, as a percentage of our alternative estimate of base year opex after base adjustments, of 9.4%.

In relation to Evoenergy's argument on benchmarking limitations, we consider that while our benchmarking tools are not perfect, this does not limit us from using them in revenue determination processes to assess the efficiency of opex in a proposed base year. Particularly important in this regard is that in our application we only apply results where we consider they reliably inform our overall base year opex efficiency assessment e.g. by removing the results of econometric opex cost function models that do not satisfy

[32] Evoenergy, *Attachment 2 Operating Expenditure*, January 2023, p. 18.

[33] Evoenergy, *Appendix 2.1 Base year efficiency*, January 2023, pp. 5–6.

monotonicity requirements. Further, that using a 0.75 comparison point, adjusted for material OEFs, instead of 1.0, inherently builds in a degree of conservativeness in part reflecting that we acknowledge our benchmarking tools are not exactly precise or perfect tools.

We discuss the choice of base year in section 6.4.1.1 and set out our analysis of the efficiency of base year opex in section 6.4.1.2.

6.4.1.1 Proposed base year

Evoenergy proposed a base year of 2021–22 and base year opex of $67.4 million ($2023–24) or $337.2 million ($2023–24) over the five years of the next regulatory control period.

Evoenergy considered 2021–22 is an appropriate base year as it:

- Is the most recent regulatory year for which actual audited data is available for the regulatory submission
- Captures expenditure required to sustainably maintain safety and service standards, meet and manage network demand within the current operating environment, consistent with customer expectations
- Reflects revealed efficient costs under an incentive based regulatory framework, incorporating the efficiency gains that Evoenergy has achieved to date, including incurring expenditure below the AER's approved efficient regulatory allowance
- Accounts for the current and prudent costs to comply with all applicable regulatory obligations and requirements associated with the provision of SCS, as required under the NER.[34]

Consistent with our preferred approach, we accept 2021–22 as Evoenergy's base year. This is because it is based on actual opex and we consider it is reasonably representative of the nature of base opex costs that are required for the next regulatory control period. Were Evoenergy to adopt 2022–23 as the base year in its revised proposal given actual data would be available, we would consider as a part of our final decision if that would be an equally or more representative year.

We have updated the base opex amount for 2021–22 to $66.4 million ($2023–24) or $332.1million ($2023–24) over the next regulatory control period. The difference between Evoenergy's proposed amount and our alternative estimate is due to:

- the use of different inflation forecasts. We have used the latest inflation forecasts published by the Reserve Bank of Australia (RBA).[35] We consider these inflation forecasts are the best forecast possible in the circumstances because they are the most up-to-date information available
- a minor correction we made to the way Demand Management Innovation Allowance (DMIA) costs were accounted for in Evoenergy's opex model.[36]

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[34] Evoenergy, *Attachment 2 Operating Expenditure*, January 2023, p. 18.

[35] RBA, *Statement on Monetary Policy – Forecast table*, August 2023.

[36] Evoenergy's model added DMIA costs to base year opex that was already inclusive of DMIA costs, before removing DMIA costs.

6.4.1.2 Efficiency of Evoenergy’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 and particularly whether its opex in the base year is higher than our estimate of efficient opex.

6.4.1.2.1 Analysis of Evoenergy’s revealed costs

Figure 6.1 shows Evoenergy’s opex forecast for the next regulatory control period, its actual opex in previous regulatory control periods, our previous regulatory decisions and our alternative estimate that is the basis for our draft decision.

We have seen a slight increasing trend in Evoenergy’s opex since 2015–16 when it decreased to its lowest level ($52.0 million ($2023–24)). This substantial drop in opex (approximately 45%) occurred early in the last regulatory control period – coinciding with the AER’s 2014–19 reset decision in which we found Evoenergy’s base opex was materially inefficient. This was at the time in which Evoenergy made large workforce reductions as part of a restructure of its organisation.[37] Following this large reduction, there was an increase in Evoenergy’s actual opex of approximately 15% in each of 2016–17 and 2017–18 years and opex rose to $69.2 million ($2023–24). Despite some decreases, and offsetting increases in following years, actual opex in the 2021–22 base year is broadly the same as it was in 2017–18 at $67.7 million ($2023–24). Evoenergy has estimated opex in 2022–23 and 2023–24 will be slightly higher at around $70.3 million ($2023–24).

Over the last two regulatory control periods, including the current regulatory control period, Evoenergy’s actual opex has generally been below the AER’s forecast, other than in 2014–15 when it was 17.9% higher and in 2017-18 when it was 7.0% higher. In the current regulatory control period, the actual and estimated opex is forecast to be 5.3% below the AER’s forecast. In its proposal, Evoenergy noted that this was achieved despite significant cost pressures in a challenging economic environment and additional regulatory obligations which it needed to comply with.[38]

While Evoenergy has performed creditably against the AER’s opex forecasts over the last two regulatory control periods, we note it did not maintain its initial opex reductions at the start of the 2019–24 regulatory control period. Further, we consider it has not been able to achieve the same degree of cost reductions as some of the other distribution businesses, as indicated by is benchmarking performance (see next sections).

37 AER, *Evoenergy 2019-24 - Draft decision - Attachment 6 - Operating expenditure*, September 2018, pp. 19–23.

38 Evoenergy, *Attachment 2: Operating expenditure*, January 2023, p. 11.

6.4.1.2.2 Benchmarking the efficiency of Evoenergy's opex over time

In line with our standard approach, we have used our benchmarking tools and other cost analysis to assess and establish whether Evoenergy is operating relatively efficiently, both over time and in the base year. We conclude that Evoenergy performs less well on opex efficiency measures compared to other networks, and that its benchmarking results indicate material inefficiency over time and in the base year.

Benchmarking broadly refers to the practice of comparing the economic performance of a group of service providers that provide the same services as a means of assessing their relative performance. Our *2022 Annual Benchmarking Report* includes 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 NEM.[39]

While opex at the total level is generally recurrent, year-to-year fluctuations can be expected. To shed light on Evoenergy's general level of operating efficiency, we first look at the efficiency of Evoenergy's opex over a period of time, using our top-down benchmarking tools, as well as other supporting techniques. This is followed (in section 6.4.1.2.3) by looking at the efficiency of opex in the base year (2021–22).

Period-average econometric opex cost function efficiency scores

This section presents the results of four econometric opex cost function models that compare the relative opex efficiency of DNSPs in the NEM. These model the relationship between opex (as the input) and outputs, and so measure opex efficiency. The results presented reflect an average efficiency score for each DNSP over a specified period. The periods we look at are the 2006 to 2021 (long) period and the 2012 to 2021 (short) period. The four econometric opex cost function models presented in this section represent the combination of two cost functions (Cobb-Douglas and Translog) and two methods of estimation (Least Squares Econometrics (LSE) and Stochastic Frontier Analysis (SFA)), namely:

- Cobb-Douglas Stochastic Frontier Analysis (SFACD)
- Cobb-Douglas Least Squares Econometrics (LSECD)
- Translog Stochastic Frontier Analysis (SFATLG)
- Translog Least Squares Econometrics (LSETLG).

In terms of historical performance, the results from the four econometric opex cost function models in the *2022 Annual Benchmarking Report* indicate that Evoenergy's opex over the benchmarking periods has been relatively inefficient. In that report, Evoenergy was ranked twelfth out of 13 DNSPs in the long benchmarking period and last out of 13 DNSPs in the short benchmarking period on the econometric opex cost function model-average efficiency scores.[40]

For this draft decision, we have updated the econometric opex cost function model results from the *2022 Annual Benchmarking Report* for the following developments since its release:

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[39] AER, *Annual Benchmarking Report - Electricity distribution network service providers*, November 2022.

[40] AER, *Annual Benchmarking Report - Electricity distribution network service providers*, November 2022, pp. 34–35.

- Updated RMD for Evoenergy which it included in its proposal to address historical reporting errors in maximum demand (MD) data it had identified.[41]
- Our approach to addressing the impact of differences in capitalisation on the benchmarking results.[42]

Each of these issues is discussed in the two following sections. We consider making both of these updates is appropriate for this draft decision as it reflects the most up-to-date data/approaches. In addition, these updates will be incorporated into the *2023 Annual Benchmarking Report*, the results of which we will draw on for our final decision.

In its proposal, Evoenergy presented its implementation of our benchmarking approach to assess the efficiency of Evoenergy's actual opex in the proposed base year of 2021–22. In doing so, Evoenergy updated its RMD, as discussed below.[43] In relation to capitalisation, Evoenergy noted that given that the outcome of our consultation process on this matter had not yet been finalised, Evoenergy had not incorporated into the benchmarking analysis presented in its proposal any of the possible options for accounting for capitalisation differences considered by the AER.[44]

Revised maximum demand data for Evoenergy

Evoenergy proposed to revise its historical data for MD from 2015 and, consequently, given RMD is calculated from MD over time it also proposed revised RMD data. RMD is one of the outputs that we use in our benchmarking models and any data revisions will impact the benchmarking results produced by these models. The changes in MD data are shown in Table 6.5.

Table 6.5 Evoenergy's revised maximum demand data 2014–21

Year	Historical data (MW)	Evoenergy revised data (MW)	Difference (MW)	Difference (%)
2014	669.9	669.9	0.0	0.0
2015	724.0	732.7	8.7	1.2
2016	669.2	669.2	–0.0	0.0
2017	682.0	688.5	6.5	0.9
2018	690.9	811.8	120.9	17.5
2019	691.0	690.5	–0.5	–0.1
2020	684.0	778.8	94.8	13.9
2021	664.0	844.3	180.3	27.2

Source: Economic Benchmarking RINs, 2014–2021; Evoenergy, *Information request EVO IR#002 – Revised maximum demand data – 20220228 – PUBLIC;* AER analysis.

41 Evoenergy, *Appendix 2.1 Base year efficiency*, January 2023, pp. 18–22.

42 AER, *How the AER will assess the impact of capitalisation differences on our benchmarking – Final guidance note*, May 2023.

43 Evoenergy, *Appendix 2.1 Base year efficiency*, January 2023, p. 5.

44 Evoenergy, *Appendix 2.1 Base year efficiency*, January 2023, p. 25.

Table 6.5 shows that the changes in MD in 2018, 2020 and 2021 are material: 17.5% in 2018, 13.9% in 2020 and 27.2% in 2021.

Based on information in Evoenergy's proposal[45] and information request responses[46], we understand the update was primarily to correct certain errors it found in updating its database, which arose in connection with the outputs delivered by its dual-function assets. Evoenergy explained that it obtains data from the Australia Energy Market Operator (AEMO) on energy flows through Transgrid's four transmission connection points.[47] This data is loaded into cloud-based master databases and is then downloaded into an SQL database which is more convenient for extracting data. Evoenergy submitted that it found that, due to coding shortcomings, updates to the cloud-based master databases had not been fully reflected in the SQL database. Evoenergy stated that the reason for the erratic behaviour of the script used to extract the Regulatory Information Notice (RIN) reported MD data was that it contained an error whereby revised metering data was not being recognised if the revised data timestamp was less than 10 hours newer than the existing timestamp.

We have assessed the rationale for the revision, including with the advice of our technical advisers and our benchmarking consultant Quantonomics, and are satisfied that the revised data is an appropriate correction. We accept that a metering data management error occurred that led to incorrect MDs being reported. We also accept that the error in the metering data management process has been corrected and the MD is now being correctly reported. As a result, we also accept the resulting changes to RMD Evoenergy proposed.

Capitalisation final guidance note

On 26 May 2023 we published our final guidance note on how we will address impacts on the benchmarking results of material differences in DNSPs' capitalisation practices (covering accounting policy and opex/capital trade-offs).[48] Our final approach was to amend our benchmarking by allocating 100% of corporate overheads expenditure to opex for benchmarking purposes. This was on the basis that it addresses a material and known source of capitalisation differences. We stated that we intend to adopt this approach for our electricity distribution annual benchmarking reports, starting from 2023 (available November 2023). Given we will draw on the *2023 Annual Benchmarking Report* for our final decision, we consider it appropriate for this draft decision to be informed by an update to the results in the 2022 report for this approach.

Updated period-average efficiency scores (for RMD data and addressing differences in capitalisation approaches)

The econometric opex cost function benchmarking results, updated for the above factors, are presented in Figure 6.4 over the long period (2006–21). This shows that over this period Evoenergy's (EVO) ranking is very slightly changed with the above updates, moving to last out of 13 distribution businesses based on the average efficiency scores from four econometric benchmarking models. Evoenergy's average efficiency score across the

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45 Evoenergy, *Appendix 2.1 Base year efficiency*, January 2023, pp. 18–22.

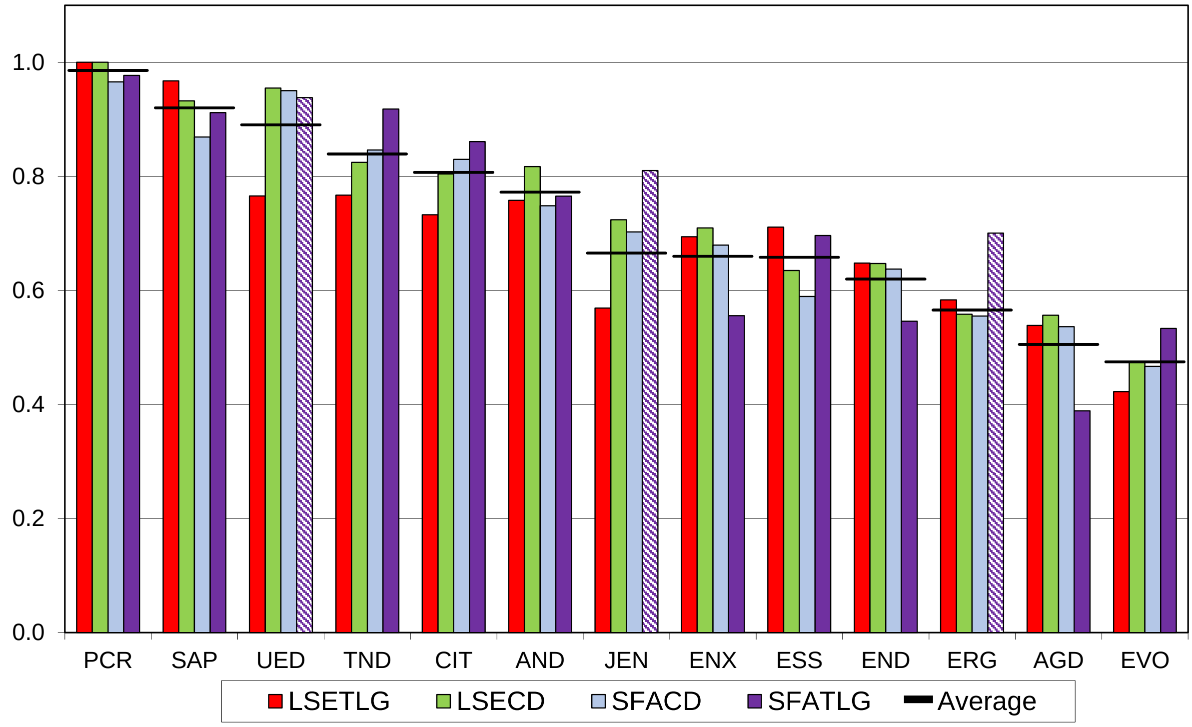
46 Evoenergy, *Information request EVO IR#002 – Revised maximum demand data*, 28 February 2023.

47 These are: Canberra, Stockdill, Williamsdale and Queanbeyan substations.

48 AER, *How the AER will assess the impact of capitalisation differences on our benchmarking – Final guidance note*, May 2023.

included models has, however, not changed and remains 0.47, noting that this does not account for the presence of material operating environment factors (OEFs), as discussed further below. The best possible efficiency score is 1.0. Our standard approach is to use a 0.75 comparison point, rather than 1.0, to recognise data and modelling imperfections when assessing the relative efficiency of distribution businesses to the benchmark comparators. Where the econometric model-average score is below 0.75, we take this as prima facie evidence that a DNSP has been operating materially inefficiently over the relevant period. With a model-average score below 0.50, this is clearly the case with Evoenergy's efficiency score performance.

Figure 6.4 Distribution businesses' average opex efficiency scores, 2006–2021[49]



Source: Quantonomics, *Benchmarking results for the AER, November 2022*; AER analysis (to incorporate updates for revised RMD data for Evoenergy and to implement our approach to addressing capitalisation differences).

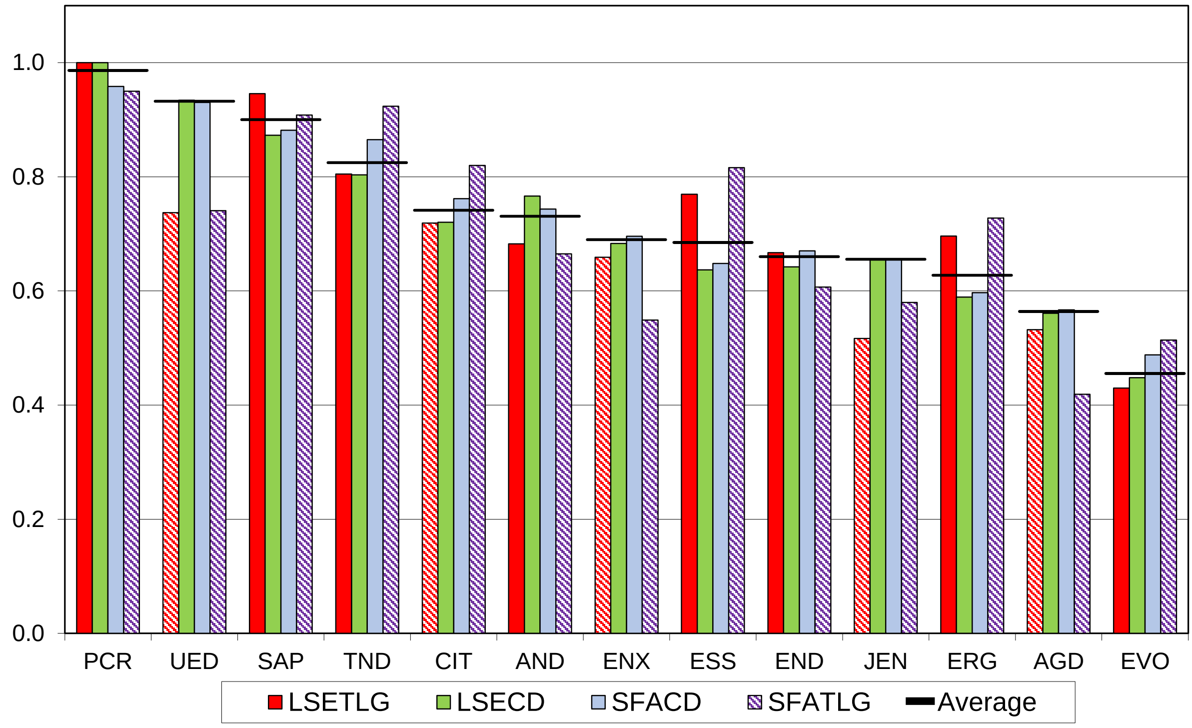
Note: Columns with a hatched pattern represent results that do not satisfy the monotonicity requirement (that an increase in output is only achieved with an increase in opex) and are not included in the model-average efficiency score for each DNSP (which is represented by the black horizontal line).

It can take some time for more recent improvements in efficiency by previously poorer performing distribution businesses to be reflected in period-average efficiency scores. Considering this, we have also examined Evoenergy's average performance over the shorter and more recent 2012–21 time period as can be seen in Figure 6.5 (EVO). With the updates

49 The results for the Energy Queensland businesses (Energex and Ergon Energy), are more preliminary as they are based on a provisional treatment of a zero allocation of capitalised corporate overheads to opex for benchmarking purposes. Our assessment of Energy Queensland's proposed capitalised corporate overheads was ongoing at the time of publication. However, our sensitivity testing showed that the impact on other DNSPs' efficiency scores was immaterial using a wide range for Energex's and Ergon Energy's capitalised corporate overheads.

noted above, Evoenergy's model-average score over the 2012–21 period has decreased from 0.47 to 0.46, and is again ranked last of the 13 distributors.[50] This indicates that Evoenergy has not materially improved its efficiency relative to its peers over the 2012–21 period, compared with its efficiency over the 2006–21 period, again noting that this does not account for the presence of OEFs. In part this is explained by other distributors improving their performance since 2012.

Figure 6.5 Distribution businesses' average opex efficiency scores, 2012–2021[51]



Source: Quantonomics, *Benchmarking results for the AER - Distribution*, November 2022; AER analysis (to incorporate updates for revised RMD data for Evoenergy and to implement our approach to addressing capitalisation differences).

Note: Columns with a hatched pattern represent results that do not satisfy monotonicity (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 the case of the SFATLG model, this does not satisfy monotonicity for the majority of Australian DNSPs. As discussed below, under these circumstances we exclude the model from calculating the model-average efficiency score for all Australian DNSPs (even though the property is satisfied for some DNSPs).

We note that our standard approach is to exclude econometric opex cost function models from the calculation of the model-average efficiency scores where the monotonicity property has not been satisfied. Monotonicity is a key economic property required for these econometric opex cost function models, which is that an increase in output can only be achieved with an increase in inputs (opex), holding other things constant. The Cobb-Douglas models estimated at sample mean have been found to satisfy monotonicity because the output coefficients are positive. However, the more flexible Translog models allow for output

50 Noting the exclusions for monotonicity as discussed below.

51 The footnote in Figure 6.4 also applies here.

elasticities (i.e., the responsiveness of opex to an increase in a particular output) to vary between each data point, and this property may not always hold. Therefore, when estimating the Translog models, satisfaction of the requirement has to be checked for each observation. Based on the advice of our consultant Quantonomics, we require this property to hold for at least half the data points of a business in order to include the efficiency score from a Translog model in our efficiency assessment. In addition, if a model does not satisfy monotonicity for the majority of Australian DNSPs, then we exclude the model from calculating the model-average efficiency score for all Australian DNSPs (even though the property may be satisfied for some DNSPs).

The hatched columns in Figure 6.4 and Figure 6.5 represent exclusions from the model-average efficiency scores as a result of the model not satisfying the monotonicity requirement. For the long period this reflects that there were monotonicity violations for United Energy, Jemena and Ergon in the SFATLG models for more than half the data points. For the short period it reflects that monotonicity was not sufficiently satisfied for the majority of the Australian DNSPs for the SFATLG model and United Energy, CitiPower, Energex, Jemena and Ausgrid for the LSETLG model. Hence the scores from the SFATLG model for all the DNSPs, and from the LSETLG model for the five DNSPs, are not used in calculating model-average score for relevant DNSPs. We discuss the issue of monotonicity further in section 6.4.1.2.4 on benchmarking limitations.

Following our standard approach, where the econometric model-average score over the long and short benchmarking periods respectively are below 0.75, which is the case for Evoenergy, we directly test the efficiency of the DNSP's actual opex in the base year. This involves application of our economic benchmarking roll-forward-model. Importantly, this also includes adjusting for the presence of material OEFs, via post-modelling adjustments to the 0.75 comparison point, for factors not already captured in the modelling. Allowing for material OEFs enables us to account for some factors beyond a distributor's control that can materially affect its benchmarking performance. This is discussed further in section 6.4.1.2.3. Before examining this we also consider Evoenergy's benchmarking performance via other benchmarking techniques.

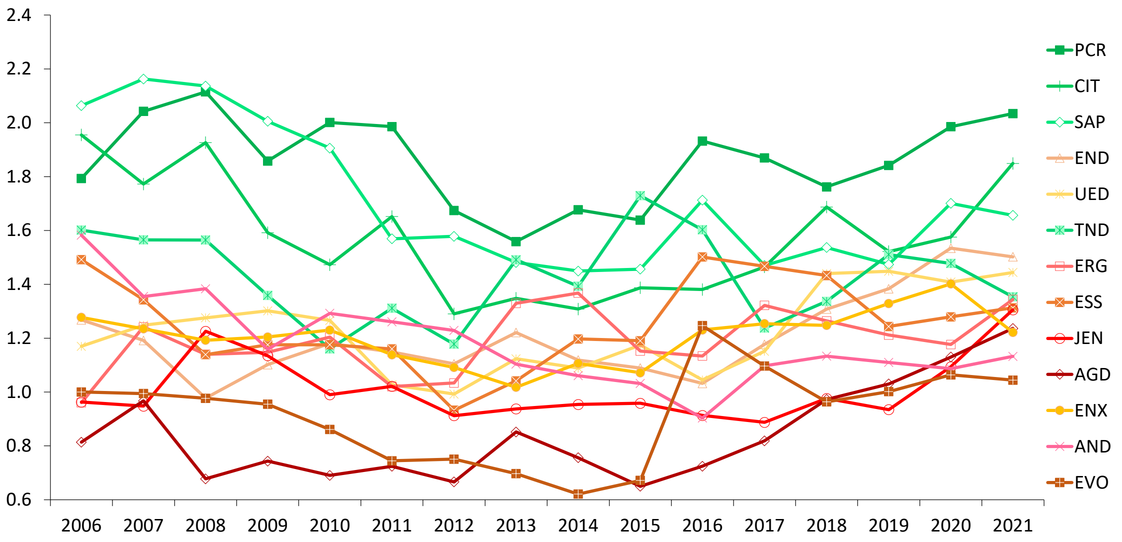
Opex multilateral partial factor productivity (MPFP) over time

We also use productivity index number techniques to enable comparisons of productivity levels over time and between businesses. The multilateral total factor productivity (MTFP) index measures the total factor productivity of each business, 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 not adjusted for material OEFs.

Unlike the econometric opex cost function modelling, at this stage we have not updated the MTFP / MPFP modelling from the *2022 Annual Benchmarking Report* for Evoenergy's updated RMD data and for our preferred approach to addressing capitalisation issues. In relation to the latter, we consider there are further implementation issues which need to be worked through to determine if and how this can be undertaken.[52] The absence of updating to the MTFP / MPFP modelling somewhat moderates direct comparability to the econometric results.

The results from our opex MPFP analysis can be seen in Figure 6.6 where a higher score means that a DNSP is more efficient relative to its peers. Evoenergy has typically ranked among the poorer performing distribution businesses in terms of opex MPFP. Evoenergy's performance has remained fairly consistent since 2006, other than an increase in measured opex MPFP in 2015–16, following large reductions in opex, as discussed above. However, Evoenergy's performance has worsened since then. Evoenergy has been amongst the worst two performers over the last four years, including in 2020–21 when it was the worst performer. The relatively improved performance of other distribution businesses, particularly Ausgrid and Jemena, is a factor here, noting that these two businesses were previously the two poorest performers. Evoenergy's average ranking over the full 2006–21 period is twelfth.

Figure 6.6 Opex MPFP by individual businesses, 2006–21



Source: AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2022.

We note that the opex MPFP results are broadly consistent with the econometric opex cost function results and also suggest relative inefficiency of Evoenergy over time, again noting the caution on direct comparisons with the results presented above given the updates we have made to the econometric opex cost function results.

Partial Performance Indicators and cost category analysis

We have also examined the relative opex performance of Evoenergy over the five-year period (2017 – 2021) using partial performance indicators (PPIs).[53] PPIs provide some information about the total and category specific opex performance of a business in

52 These include: what adjustments would be required to (decrease) the capex series to recognise the capitalised corporate overhead costs being incorporated as opex. This would have flow on impacts to the annual user costs (AUC) which are used as the weights for the capital inputs in the MTFP/MPFP modelling; and how to make any adjustments to the historical capex and related AUC series.

53 We have not updated the PPI analysis for our preferred approach to addressing capitalisation issues.

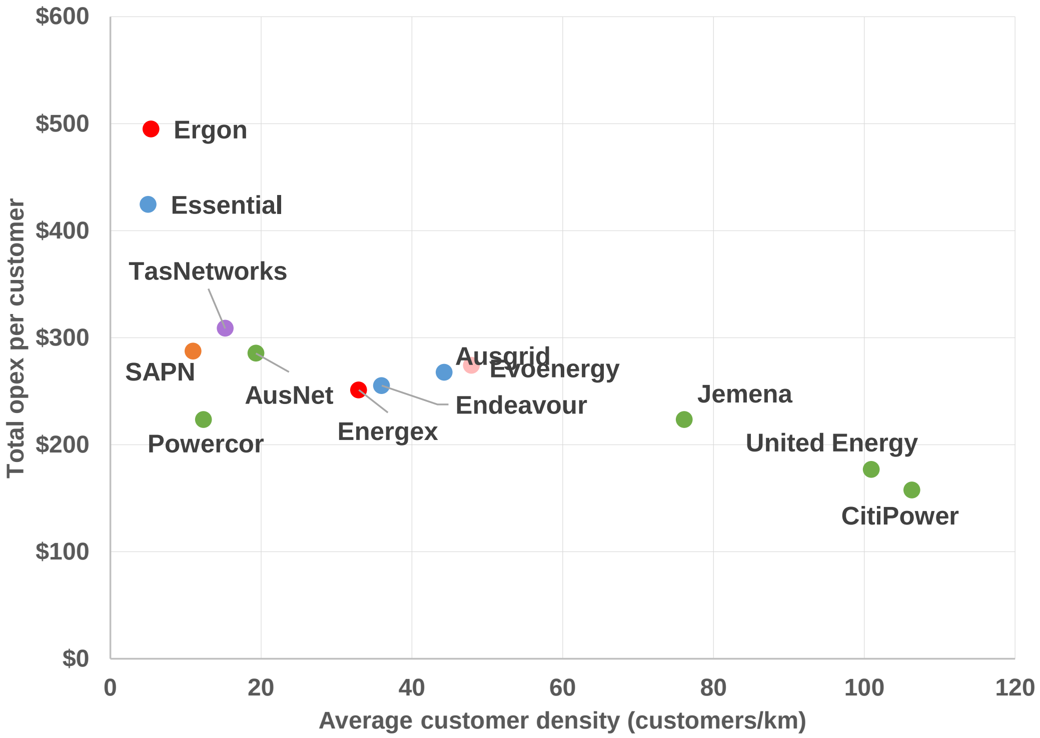
delivering a given type of output and may help in understanding potential drivers of relative efficiency or inefficiency. Although they are more simplistic measures, the PPI results can provide further insights and evidence to cross check our top-down economic benchmarking. It is important to note that rankings for PPIs may be affected by factors outside the control of the distribution businesses and must be analysed with caution, with comparisons generally limited to businesses with similar characteristics, e.g. customer density.

The evidence on Evoenergy's performance on the range of opex PPIs is not consistent and depends on the output considered. Evoenergy tends to perform better on opex 'per customer' metrics but relatively less well on opex 'per circuit length' metrics. This is expected as largely urban businesses such as Evoenergy have denser distribution networks and tend to perform better on 'per customer' metrics than their rural counterparts, whereas, on 'per km' metrics, more rural DNSPs will perform better because their costs are spread over a longer network. The partial nature of PPIs, compared to the ability of the top-down economic benchmarking to consider all outputs holistically, is one of the key reasons we primarily rely on the top-down benchmarking for resets.

The total opex per customer PPI is presented in Figure 6.7 and total opex per km of circuit line length presented in Figure 6.8. As noted above, care must be taken drawing conclusions from PPI analysis. For Evoenergy, this is particularly the case given its situation is relatively unique in terms of its customer density. That said, we observe in Figure 6.7 that Evoenergy's total opex per customer is not particularly low when considering it has similar or higher opex per customer as distribution businesses of less than half its customer density (e.g. AusNet Services, Powercor). We can expect a negative relationship between opex per customer and customer density because, all else equal, the cost of managing the same number of customers connected to a shorter network will tend to be lower. This generally negative relationship between opex per customer and customer density is visible in the figure.

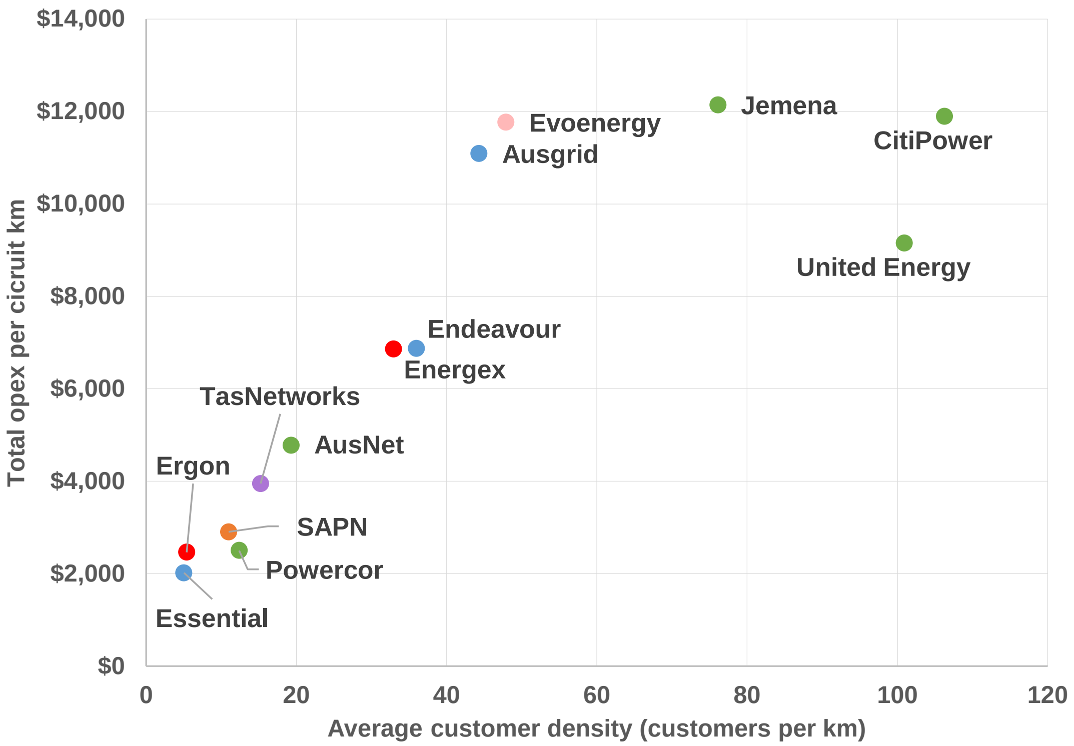
Similarly, Evoenergy's total opex per circuit length km is not particularly low, particularly considering it is at a similar or higher level than DNSPs with higher customer density (Jemena, CitiPower, United Energy). We can expect a positive relationship between opex per km and customer density because, all else equal, the costs are spread over a longer network.

Figure 6.7 Total opex per customer against customer density (2017–21 average) $Jun2021



Source: AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2022

Figure 6.8 Total opex per km of circuit line length against customer density (2017–21 average) $Jun2021



Source: AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2022

6.4.1.2.3 Benchmarking the efficiency of Evoenergy's base year opex

Given the evidence outlined above about the relative inefficiency of Evoenergy's opex over the 2006–21 period and the more recent 2012–21 period (via the econometric opex cost function and opex MPFP benchmarking results), as well as the absence of counter-evidence in the supporting PPI analysis noting their limitations, we have undertaken further analysis.

Following past decisions, this includes application of our economic benchmarking roll-forward-model, which includes adjusting for material OEFs and setting the comparison point at 0.75, to directly test the efficiency of Evoenergy's actual opex in the base year. We use results from our econometric opex cost function benchmarking and our benchmarking roll-forward model to derive an estimate of efficient base year opex, and compare this to actual base year opex, in order to determine whether there is an efficiency "gap" and of what size.[54] Where modelled efficient rolled-forward base year opex is below actual base year opex, we infer that the latter is materially inefficient. We reach this conclusion for Evoenergy. This section sets out how we have derived the efficiency gap for Evoenergy in the following sub-sections, reflecting the process described above:

- First, deriving the estimated efficient rolled forward opex (plus capitalised corporate overheads) in the base year, taking into account OEFs which are separately discussed and the 0.75 comparison point, and considering Evoenergy's argument in relation to accounting for step changes in the benchmarking roll-forward model
- Second, determining the actual base year opex (plus capitalised corporate overheads), including any appropriate adjustments to actual opex
- Third, calculation of the efficiency gap between the estimated efficient rolled-forward opex in the base year and actual base year opex (both inclusive of capitalised corporate overheads).

As discussed in section 6.4.1.2.5, we then draw on the efficiency gap from this modelling to inform an efficiency adjustment to base opex. MTFP / MPFP and PPI benchmarking is not used as a part of this further testing.

Deriving the estimate of efficient rolled-forward base year opex

As outlined above, our econometric opex cost function models produce average opex efficiency scores for distribution businesses across the 2006–21 and 2012–21 periods respectively. Using our benchmarking roll-forward-model, we convert these period-average results into an estimate of the level of network services opex[55] required by an efficient service provider operating in Evoenergy's circumstances in base year 2021–22.

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54 In this application to Evoenergy, we have applied the results updated for the approach to capitalisation practices, which treats capitalised corporate overheads as opex for benchmarking purposes. This means that both the estimated efficient rolled-forward base year opex and actual base year opex include capitalised corporate overheads. As discussed further below, the resulting efficiency gap is expressed in percentage terms, and applied as an efficiency adjustment to SCS opex (excluding capitalised corporate overheads) in the opex model.

55 We benchmark distribution businesses on the basis of the network services component of standard control services opex, which comprises the majority of standard control services opex. Network services opex excludes opex categories that are part of standard control services opex, such as opex for metering, customer connections, street lighting, ancillary services and solar feed-in tariff payments.

Using our benchmarking roll-forward model, we first apply Evoenergy's efficiency scores to its period-average opex to obtain a period-average efficient level of opex for Evoenergy.[56] This takes account of material OEFs and the benchmarking comparison point of 0.75. This estimated efficient period-average opex is then rolled forward from the mid-point year (of the relevant benchmarking period) to the base year (2021–22 in this case) using the parameters of the econometric opex cost function model to account for the drivers of efficient opex. This includes output growth, opex partial productivity change that incorporates the impact of the estimated time trend, undergrounding and returns to scale. We outline our approach in further detail in recent decisions.[57]

In summary, we have estimated the model-average rolled forward efficient opex (plus capitalised corporate overheads) in the base year for the long period to be $62.2 million ($ Regulatory Year (RY) 2021[58]) and $54.3 million ($RY 2021) for the short period, for an average of $58.2 million ($RY 2021). This average is $10.8 million ($RY 2021) or 15.7% less than actual base year opex (plus capitalised corporate overheads) of $69.1 million ($RY 2021). The results for the estimated rolled-forward efficient opex (plus capitalised corporate overheads) in the base year for each model are shown in more detail in the section discussing the efficiency gap between the estimated rolled-forward base opex and actual base year opex.

The following sections discuss two elements in the calculation of the estimated rolled-forward efficient opex in the base year:

- Our approach to making OEF adjustments in general, as well as discussion in relation to some specific OEFs we apply for Evoenergy. We have applied these OEF adjustments in determining the estimated efficient rolled-forward base year opex.
- Consideration of whether further allowance needs to be made for the costs of a vegetation management step change when estimating efficient opex in the base year, as proposed by Evoenergy.

Operating Environment Factor adjustments

Distribution businesses do not all operate under exactly the same operating environments. Our economic benchmarking techniques account for differences in operating environments to a significant degree, including through the data used to ensure a common scope of services provided, and through the econometric models which incorporate variables related to the share of undergrounding and network densities. However, our benchmarking models do not

[56] As explained above, this also includes capitalised corporate overheads.

[57] AER, *Final Decision - Jemena determination 2021–26 - Attachment 6 – Operating Expenditure*, April 2021, p. 25.

[58] Consistent with our benchmarking, the figures in our benchmarking roll-forward model are expressed in constant-price or 'opex quantity' terms, whereby the nominal (mid-year) opex series is deflated into constant-price dollars of the last year of the dataset used in the benchmarking for the most recent Annual Benchmarking Report. The benchmarking roll-forward model used in this decision draws on the results of our 2022 Annual Benchmarking Report, which incorporates data up to regulatory year 2021, which in the case of the NSW/ACT DNSPs is Financial Year 2021. This means the opex figures are in constant-price $December 2021 dollars. They are therefore not comparable to figures expressed in $2023–24 terms. However, the purpose and output of the roll-forward model analysis is the efficiency gap, expressed in percentage terms.

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directly account for all factors, such as differences in legislative or regulatory obligations, climate and geography.

Given this, we also consider post-modelling OEF adjustments as a part of our benchmarking analysis. This enables us to assess the efficiency of a distribution business's operations on a more like-for-like basis to inform our assessment of whether its base year opex is materially inefficient or not. We make this adjustment by quantifying the material OEFs to adjust the benchmark comparison point (upwards for negative OEFs, downwards for positive OEFs) to account for the operating environment of the distribution business we are assessing. This adjusted comparison point is then compared to the business's efficiency score (from the benchmarking models), allowing us to account for potential cost differences due to material OEFs between the business and the benchmark comparison businesses. More detail on the mechanics of our approach is contained in past decisions.[59]

Based on a 2018 review carried out by our consultant Sapere-Merz, we have identified a limited number of OEFs that materially affect the relative opex of each business in the NEM. Sapere-Merz consulted with stakeholders, including the electricity network businesses, in undertaking this review.[60] This review established three criteria for identifying relevant OEFs:

- Exogeneity: Is it outside of the service provider's control? Where the effect of an OEF is within the control of the service provider's management, adjusting for that factor may mask inefficient investment or expenditure.
- Materiality: Is it material?[61] Where the effect of an OEF is not material, we would generally not provide an adjustment for the factor. Many factors may influence a service provider's ability to convert inputs into outputs.
- Non-duplication: Is it accounted for elsewhere? Where the effect of an OEF is accounted for elsewhere (e.g. within benchmarking output measures), it should not be separately included as an OEF. To do so would be to double count the effect of the OEF.

Based on these criteria, the material OEFs Sapere-Merz identified which we now use are:

1. The higher operating costs of maintaining sub-transmission assets
2. Differences in vegetation management requirements
3. Jurisdictional taxes and levies
4. The costs of planning for, and responding to, cyclones (Ergon only)
5. Backyard reticulation (in the ACT for Evoenergy only)
6. Termite exposure.

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59 AER, *Preliminary Decision - Ergon Energy determination 2015–20 - Attachment 7 – Operating Expenditure*, April 2015, pp. 93–138; AER, *Draft Decision - Ausgrid Distribution determination 2019–24 - Attachment 6 – Operating Expenditure*, November 2018, pp. 31–33; AER, *Draft Decision - Endeavour Energy Distribution determination 2019–24 - Attachment 6 – Operating Expenditure*, November 2018, pp. 27–29.

60 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018.

61 We have generally treated any OEF that will increase a service provider's opex by 0.5 per cent or more, relative to other service providers, as material. In practice, if an OEF is found to be material for one of the DNSPs, we have generally quantified the OEF impact for all DNSPs, and calculated the OEF adjustment accordingly.

The reasoning and process that we, and Sapere–Merz, went through to identify these OEFs is set out in detail in Sapere–Merz's report[62] and summarised in our *2018 Annual Benchmarking Report*.[63]

Table 6.6 shows for each of these material OEFs that are relevant to Evoenergy, our calculated OEF adjustments for Evoenergy for the long and short benchmarking periods. It also includes a new OEF for workers' compensation cost differences. It excludes jurisdictional taxes and levies, as this OEF was excluded for Evoenergy in the Sapere-Merz process. This was because it was considered that where DNSPs recover taxes and levy costs through recovery mechanisms other than standard control tariffs, inclusion of some taxes and levies in an OEF adjustment could breach the non-duplication criterion.[64] In Evoenergy's case, it was understood that it recovered these costs via the B factor in annual pricing determinations, and hence this OEF was not calculated for Evoenergy. We request further information from Evoenergy in its revised proposal in relation to the status of the payment and recovery of its jurisdictional taxes and levies, and whether or not it would be appropriate to account for these costs in the OEF framework.

As noted above, the OEF adjustments for Evoenergy in Table 6.6 are used to adjust the 0.75 comparison point and are incorporated into the analysis below (under the heading *Calculating the efficiency gap* and as shown in Figure 6.9 and Figure 6.10).[65]

Table 6.6 OEF adjustments for Evoenergy, %

OEF	2006–21 period	2012–21 period
Sub-transmission (Licence conditions)	-0.40	-0.17
Termite exposure	0.02	0.03
Backyard reticulation	3.53	3.44
Workers' compensation	0.75	0.75
Vegetation management (bushfire)*	-2.94	-4.2
Vegetation management (division of responsibility)*	0.0	0.0
Total	1.0	-0.1

Source: AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2022; Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018; AER analysis.

*Note: While Sapere-Merz identified vegetation management as a material OEF, it did not quantify it given data issues. We have calculated the OEF for vegetation management, as explained below.

These results indicate that Evoenergy incurs net cost disadvantages and advantages over the two benchmarking periods (1.0% and –0.1% respectively) relative to the benchmark

62 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018; AER, *Annual Benchmarking Report - Electricity distribution network service providers*, November 2018, pp. 23–29.

63 AER, *Annual Benchmarking Report - Electricity distribution network service providers*, November 2018, pp. 23–29.

64 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018, p. 70.

65 The spreadsheets used to calculate these adjustments are published along with this decision.

comparator businesses.[66] That is, relative to the benchmark comparator businesses Evoenergy incurs relatively more costs in the long period and slightly less in the short period, given its operating environment. As per our standard approach, we adjust our benchmark comparison point of 0.75 to account for these cost disadvantages / advantages. The most material of these adjustments are discussed below. We do not discuss below the sub-transmission and termite exposure OEF adjustments as we have applied mechanical updates using the Sapere-Merz OEF model.[67]

We note that these OEFs for Evoenergy are significantly fewer, and the adjustments lower, than we used in the 2019–24 and 2014–19 final price reset decisions for Evoenergy. This follows refinements and review of the OEF adjustments over time, particularly the OEF review led by Sapere-Merz.[68] In the 2014–19 final decision for Evoenergy, a number of material OEFs were quantified for the first time. In addition, we included OEFs that individually may have had an immaterial impact on opex, but their collective effect may have been material. In that final decision, this led to a significant positive OEF adjustment of 23.0% (lowering the 0.75 comparison point).

Our use of only material OEFs since the Sapere-Merz review was completed represents a change from the approach used in our 2015 and 2019 decisions for NSW/ACT distribution businesses (the latter of which retained the 2015 approach), which applied OEF adjustments that accounted for both material and immaterial OEFs.[69] The decision to include immaterial OEFs was part of a deliberate decision to adopt a cautious approach in the context of our first use of benchmarking and a more limited information set. The change in approach, and the use of only material OEFs, was based on our assessment that, based on the best available information, the continued application of the immaterial OEFs now represented an overly conservative[70] estimate of the impact of OEFs on differences in businesses' costs. The use of immaterial OEFs likely overestimates the magnitude of the differences between Evoenergy (and other DNSPs) and the comparison point firms when used in the context of identifying material inefficiency.

Our reasons for deciding to apply the material OEFs as outlined in Sapere–Merz's report in our benchmarking analysis include:

66 Following our standard approach, these are those DNSPs with an econometric model-average efficiency score of over 0.75. For simplicity and stability, for the purposes of this draft decision, we have kept the same set of comparators as under our 2022 Annual Benchmarking Report results, namely Powercor, CitiPower, SA Power Networks, TasNetworks, and United Energy, for both the long and short benchmarking periods.

67 More information on these OEFs is contained in Section 7 of the 2022 Annual Benchmarking Report: AER, *Annual Benchmarking Report - Electricity distribution network service providers*, November 2022.

68 The results from this OEF review were not incorporated into the 2019–24 final decision for Evoenergy due to the coincident timing of the reviews.

69 AER, *Final decision, Ausgrid distribution determination 2014–2019, Attachment 7 – Operating expenditure*, April 2015, pp. 181–182; AER, *Draft Decision, Ausgrid Distribution determination 2019–24, Attachment 6 – Operating Expenditure*, November 2018, p. 132.

70 Under that approach, we provided a -0.5% adjustment if the factor was likely to advantage of a DNSP; and a +0.5% adjustment if the factor was likely to disadvantage a DNSP *or* where the directional impact was uncertain. This generally provided a positive collective adjustment for immaterial OEFs that could not be easily quantified.

- Benchmarking is a top-down approach to assessing the relative efficiency of distribution businesses in the NEM. In our regulatory decisions, we use benchmarking to identify distribution businesses that are materially inefficient. This approach of benchmarking lends itself to taking into account material differences between distribution businesses rather than all differences. While previous decisions considered material and immaterial differences, this was in the context of the initial application of benchmarking and the information available to us at the time. This led to a more conservative and cautious approach to benchmarking and the calculation of OEFs.
- We have since undertaken an OEF review process that included industry-wide consultation and the development of the Sapere–Merz report in relation to material OEFs. This represented an incremental improvement from our previous analysis and decisions that we consider should be applied, noting that there are still ongoing areas for improvement.
- At this stage, we have retained the benchmark comparison score (0.75), which we consider remains relatively conservative, providing a margin to account for any residual data and modelling issues. This is in the context where, since the 2015 decisions, we now use multiple benchmarking models to better account for differences between distribution businesses (a number of different production functions and efficiency estimation techniques are therefore taken into account). As a result, we have further comfort that we no longer need to be as cautious and conservative as we initially were in our quantification of OEFs.

Further, in relation to the quantum of adjustments, the Sapere-Merz OEF review also found that some OEFs for Evoenergy were significantly lower than initially determined (e.g. backyard reticulation). Overall Sapere-Merz calculated an OEF adjustment of 0.8% for Evoenergy.[71] The OEFs for Evoenergy in this draft decision are largely consistent with the Sapere-Merz review. However, some OEFs have been updated since the Sapere-Merz OEF review e.g. for updated backyard reticulation costs. In response to Evoenergy's proposal, we also consider it is reasonable to add a further OEF for Evoenergy to recognise workers' compensation differences between DNSPs. These OEFs, along with the vegetation management OEF which we have quantified following the Sapere-Merz review, are discussed further below.

Vegetation management OEF

DNSPs are required to ensure the integrity and safety of overhead lines by maintaining adequate clearances from vegetation, which involves various activities. Vegetation management expenditure accounts for between 10–20% of total opex for most DNSPs and can differ due to factors outside of their control. Some of these factors include the length of overhead lines requiring active vegetation management; vegetation density and rate of growth; and State governments, through legislation, deciding whether to impose bushfire safety regulations on distribution businesses and how to divide responsibility for vegetation management between distribution businesses and other parties.

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71 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018, p. viii.

Our economic benchmarking models in part account for differences in vegetation management opex between distribution businesses. This is through the inclusion of a circuit line length output variable, along with the degree of undergrounding as an OEF in the actual models. Overhead line length is a potential driver for vegetation management costs, as vegetation management obligations relate to maintaining clearance between overhead lines and surrounding vegetation. However, Sapere–Merz's analysis of the Category Analysis RINs and economic benchmarking data found that the overhead line variable does not fully explain variations in regulatory obligations, and in vegetation density and growth rates across times and between different locations.[72]

Consistent with past decisions, we have adopted two vegetation management OEFs to address these differences in regulatory obligations:

- Bushfire risk obligations — the effects on opex of variations in mandated standards of bushfire mitigation activities (generally related to vegetation management), specifically the bushfire regulations in Victoria
- Division of responsibility — the differences in opex between distribution businesses due to differences in the division of responsibility for vegetation clearance between the networks and other parties, such as local councils, road authorities and landowners.

Evoenergy submitted that the bushfire risk management and division of responsibility OEFs should not be applied more widely (including to Evoenergy in the 2024–29 reset) until the AER has consulted more broadly on those OEF adjustments. Evoenergy argued that the bushfire risk management and the division of responsibility OEFs have not been subject to broad consultation of the kind undertaken by the AER as a part of the Sapere-Merz review when it developed its standard set of OEFs. It submitted that these additional OEFs were, rather, developed through the revenue resets of a small number of DNSPs, and were therefore, subject to much narrower consultation, feedback, and review by stakeholders.[73]

We do not agree with Evoenergy on this procedural point. Vegetation management was found to be a material OEF in the Sapere-Merz process. Its final report found that vegetation management meets the criteria for an OEF. Whilst it was not able to quantify a vegetation management OEF, it noted that this does not indicate that this OEF cannot be estimated by the AER on a case by case basis until such time as a systematic quantification is implemented.[74] We have applied these OEFs over a number of revenue determinations, starting in 2015 for Ergon Energy.[75] These are public processes that invite and incorporate submissions from all interested parties. We therefore consider that interested stakeholders have had opportunity to participate in the continued development of our OEF framework.

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72 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018, p. 62.

73 Evoenergy, *Evoenergy – Appendix 2.1 Base year efficiency*, January 2023, p. 24.

74 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018, p. 65.

75 AER, *Preliminary Decision - Ergon Energy determination 2015−16 to 2019−20 - Attachment 7 − Operating Expenditure*, April 2015, p. 200; AER, *Final decision - Ergon Energy distribution determination 2020 to 25 - Attachment 6 - Operating expenditure*, June 2020, pp. 24, 41–44; AER, *Final Decision - Jemena determination 2021−26 - Attachment 6 − Operating Expenditure*, April 2021, pp. 29–30.

Bushfire risk

The OEF for vegetation management (bushfire risk) exists to account for the differences in opex between distribution businesses due to differences in vegetation management obligations specifically to mitigate bushfire risk, in this case between Evoenergy and the comparator networks.

Evoenergy submitted that this OEF adjustment does not reflect the costs associated with managing bushfire risks but, rather, the impact of bushfire-related regulations imposed on Victorian networks in 2011. Furthermore, Evoenergy submitted that there have been recent changes to Evoenergy's vegetation management obligations, which are not reflected in this OEF adjustment. It noted the bushfire risk management OEF applied by the AER assumes:

- Victorian DNSPs have faced a historical cost disadvantage compared to non-Victorian DNSPs, due to more stringent obligations to manage bushfire risk; and
- this assumed cost disadvantage has remained unchanged over time, even though vegetation management obligations in non-Victorian jurisdictions have expanded.[76]

We have maintained the approach we have applied in recent determinations. This calculates the vegetation management (bushfire risk) OEF for the relevant business by quantifying the cost impact of vegetation management regulations introduced in Victoria after the 2009 Black Saturday bushfires. The increased opex expected to be incurred as a result of the new regulations is used as a proxy for the differences in costs of managing bushfire risks in Victoria since 2011 compared to other states. While we recognise this approach does not directly quantify vegetation management cost differences, we maintain it is a reasonable approximation in the absence of sufficient quality data on number and length of overhead spans and vegetation density. As noted in the *2022 Annual Benchmarking Report*, improving the data and quantification of the vegetation management OEF is a future focus of benchmarking development.[77]

To estimate Victorian vegetation management (bushfire risk) costs we have continued to use historical forecast costs associated with bushfire regulations rather than actual vegetation management costs. This is because we consider it unlikely that actual costs will reflect only changes as a result of the new obligations faced given these costs can fluctuate due to other reasons such as weather conditions and vegetation management cycles.

Division of responsibility OEF

Given the division of responsibility for vegetation management in the ACT is similar to that in states where the comparator DNSPs operate, we have retained an OEF for Evoenergy of 0% across both the long and short benchmarking periods. This is in line with our previous Evoenergy revenue determinations.[78]

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[76] Evoenergy, *Appendix 2.1 Base year efficiency*, January 2023, p. 24.

[77] AER, *Annual Benchmarking Report - Electricity distribution network service providers*, November 2022, p. 59.

[78] AER, *Final decision - ActewAGL distribution determination 2014–2019*, April 2015, p. 169; See model published with the NSW/ACT 2014–19 reset decisions: AER, *Final decision - Ausgrid distribution determination - Ausgrid 2015 - Operating Environment Factors summary*, April 2015.

In terms of division of responsibility for vegetation management in the ACT, backyard reticulation remains a key area of responsibility for vegetation management allocated to parties other than Evoenergy, i.e. private landholders. Under this arrangement, historically land holders have had primary responsibility for managing vegetation for approximately 15% of Evoenergy's route line length.[79] This is similar to the 18% of vegetation management undertaken by councils in the comparator DNSP states of Victoria and South Australia used in our division of responsibility OEF model to represent the comparator division of responsibility against which other DNSPs' divisions of responsibility are compared.[80] In addition, to the extent Evoenergy incurs costs in relation to backyard reticulation, these are captured in that OEF adjustment, as set out below.

We note the recent expansion of Evoenergy's vegetation management responsibilities arising through additional vegetation management obligations that it faces as per the step change we approved in the last regulatory control period.[81] These step changes provided for an increased opex forecast from 2018–19, the first year of that regulatory period. This was to meet the efficient costs of expanded vegetation management obligations and the new responsibility to inspect privately owned electrical infrastructures, following amendments to the *Utilities (Technical Regulation) Act 2014* (ACT). In particular, in November 2017, the *Utilities (Technical Regulation) Act 2014* (ACT) was amended to transfer the responsibility of vegetation clearing on unleased land in urban areas of the ACT from the ACT Government to Evoenergy. In addition, Evoenergy also became responsible for inspection of private poles on rural leased properties. We recognise this is a change (decrease) in division of responsibility (an increase in Evoenergy's responsibility) since the 2015 decision. We have therefore made additional adjustment for this by incorporating the additional costs faced by Evoenergy since 2019–20 in our OEF analysis.[82] This is different to the approach Evoenergy proposed in terms of making adjustments to allow for these additional obligations in the benchmarking roll-forward model used to estimated efficient opex in the base year. The approach proposed by Evoenergy is discussed further below.

We seek updated information from Evoenergy in its revised proposal on:

- whether the above finding represents the current division of responsibility in the ACT
- in relation to the step changes provided in our 2019 reset decision following amendments to the *Utilities (Technical Regulation) Act 2014* (ACT), whether these new responsibilities came into effect on 1 July 2018, and if so, whether and to what extent Evoenergy incurred costs from this date.

Backyard reticulation OEF

Historical planning practices in the ACT mean that in some areas overhead distribution lines are run along a corridor through backyards rather than the street frontage as is the practice

79 *AER, Draft decision - ActewAGL distribution determination - 2014–2019, November 2014, p. 86.*

80 In our vegetation management OEF model published with this draft decision, for the purposes of this draft decision, we have recorded a 0% for the OEF adjustment.

81 AER, *Final decision - Evoenergy distribution determination 2019-24 – Attachment 6 - Operating expenditure*, pp. 18–23.

82 We have implemented this additional adjustment via the bushfire regulations OEF sheet in our vegetation management OEF model. This is applied by offsetting the costs of the step change for the relevant number of years against the costs of the bushfire regulations facing the comparator DNSPs.

for other DNSPs. As discussed above, while private landholders are responsible for vegetation clearance in these areas, Evoenergy is responsible for ensuring public safety related to backyard lines in the ACT. In the context of backyard reticulation, this involves carrying out inspections and reactive maintenance in backyard reticulated areas.

In previous Evoenergy decisions and in the Sapere-Merz review, we recognised this as an OEF specifically relevant to the ACT and applied this as an OEF adjustment for Evoenergy.[83] We consider this factor continues to meet the three criteria for an OEF as:

- it is an exogenous feature of the ACT operating environment
- it is a material cost for Evoenergy
- the costs of this factor are not otherwise accounted for in our benchmarking analysis.

Evoenergy updated the inputs into the Sapere-Merz model to derive new cost estimates for the activities related to inspecting and maintaining backyard lines. In its proposal, drawing on actual costs in 2021–21, it estimated the cost of this OEF to be $2.0 million per year ($2023–24), updated from $0.9 million ($2023–24), as per the Sapere-Merz estimate, which was derived using previous Evoenergy data.[84] In response to our information requests it subsequently revised this estimate down to $1.6 million ($2023–24) per year.[85] The major cost drivers behind the revised cost estimate are the assumed labour rate for inspectors and the unplanned/reactive maintenance expenditure.

We have reviewed Evoenergy's revised methodology for calculation of the costs of this OEF, and consider it includes reasonable updates to the previous costings used for the Sapere-Merz process. We have therefore accepted and incorporated these updated costings in our OEF calculations.

The resulting OEF adjustment of approximately 3.5% for the backyard reticulation OEF across the long and short benchmarking periods is approximately 2 percentage points below the 5.6% OEF adjustment we used in the 2015 and 2019 Evoenergy reset decisions prior to the Sapere-Merz process. This reflects the updated methodology used in the Sapere-Merz process to limit the costings to direct costs for backyard reticulation and the updated direct cost estimates outlined above.

Workers' compensation

Evoenergy proposed a new OEF for the differences in the relative cost of workers' compensation between jurisdictions. It cited an expert report provided by insurance brokers Marsh which noted that the ACT workers' compensation scheme is the most expensive scheme for employers in any Australian jurisdiction, concluding that:

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83 AER, Final decision, *ActewAGL distribution determination, 2014–2019, Attachment 7 – Operating expenditure*, April 2015, pp. 235–236; Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018, pp. 78–81.

84 Evoenergy, *Appendix 2.1 Base year efficiency*, January 2023, p. 26; AER analysis.

85 Evoenergy, *Information request EVO IR#0037 – Backyard reticulation OEF - CONFIDENTIAL*, 18 June 2023.

> "Based on the data supplied in this report, Marsh is of the opinion that if ActewAGL Distribution were to be located in a managed fund jurisdiction such as Victoria, the premium payable for workers' compensation based on industry and risk would be less than that of the current ACT premium."[86]

Evoenergy cited Marsh data that suggested that workers' compensation premium rates for the electricity industry in the ACT are 2.7 times greater than any other state, measured in terms of average percentage of payroll. Marsh explained that the higher workers' compensation insurance premium costs faced by all employers in the ACT, including Evoenergy, are due to a number of factors, including no thresholds on eligibility and uncapped damages under common law and medical cost growth in the ACT.[87]

To quantify its proposed workers' compensation OEF adjustment, Evoenergy sought to establish these costs as a percentage of total opex. To do this it multiplied the 2017–21 average workers' compensation insurance premium in the ACT, measured as a percentage of payroll, of 2.4% to the all-DNSP-average labour proportion of costs as used by the AER in opex benchmarking of 59.2%. This gives a figure of 1.5%, representing workers' compensation premium costs as a percentage of total opex in the ACT. This was then compared to the customer-weighted average of these costs as a percentage of total opex for the comparator DNSPs of 0.7% to yield the OEF (disadvantage) of 0.75%.[88]

We have assessed Evoenergy's case for an additional OEF for workers' compensation and have accepted and incorporated it into our OEF analysis. We consider it meets the three criteria for an OEF in that this factor is exogenous to Evoenergy, it creates material differences in DNSPs' opex, and it is not otherwise accounted for, directly or indirectly. We recognise average workers' compensation premium rates vary considerably between states and territories. In particular, we accept that Evoenergy faces a material cost disadvantage relative to the comparator DNSPs due to the higher workers' compensation insurance premiums paid by employers in the ACT.

In terms of calculation, we have reviewed Evoenergy's proposed methodology, and consider it a reasonable method of calculating the cost disadvantage for Evoenergy, and consistent with our broader OEF approach. Relative to the proposed approach, we have made one minor adjustment in relation to the average labour proportion of costs. As noted above, Evoenergy adopted the all-DNSP-average labour proportion of costs of 59.2% used in the AER's benchmarking. Our preferred calculation is to adopt the (customer-weighted) average labour cost share for the comparator DNSPs, which is 60.3%, indicating the efficient payroll cost as a proportion to total opex. This is consistent with the focus on efficient costs in our broader benchmarking and OEF approach. This modification has a very minor impact on the calculated OEF adjustment.

Costs of a vegetation management step change in the base year

Evoenergy argued in its proposal that the benchmarking roll-forward procedure should, but does not, account for step changes previously approved by the AER which apply in the roll-

[86] Evoenergy, *Appendix 2.1 Base year efficiency*, January 2023, pp. 26–27.

[87] Evoenergy, *Appendix 2.1 Base year efficiency*, January 2023, p. 27.

[88] Evoenergy, *Appendix 2.1 Base year efficiency*, January 2023, pp. 27–29.

forward period and particularly in the base year.[89] Evoenergy submitted that if a DNSP has faced step changes in efficient costs over the roll-forward period, those step changes should be accounted for in the roll-forward process—for the same reason that the base-step-trend approach includes step changes.

Evoenergy specifically referred to its expanded vegetation management obligations arising from past amendments to the Utilities (Technical Regulation) Act 2014 (ACT) as outlined in the vegetation management OEF section above, which resulted in an approved step change of $2.4 million ($2018–19) per annum over the 2019–24 regulatory control period. It argued the increase in its opex in response to these expanded regulatory obligations is reflected in the historical Economic Benchmarking RIN data used by the AER to benchmark Evoenergy's costs, and to derive an average efficiency score over the historical benchmarking periods. However, it considered the step change in these costs is not accounted for anywhere in the AER's opex benchmarking roll-forward approach used to estimate an efficient level of opex for Evoenergy in the base year. In particular, Evoenergy argued the step change in efficient opex is not accounted for:

- when rolling forward efficient opex to reflect the observed growth in Evoenergy's outputs
- in the growth in real input costs over the roll-forward period
- in the rate of productivity over the roll-forward period.

We do not agree with Evoenergy's argument that step changes, including in relation to the specific step change it identified, are a gap in the benchmarking roll-forward model that need to be explicitly incorporated. We have therefore not made adjustments in our benchmarking roll-forward analysis for our alternative estimate. This is because we consider step changes are already implicitly accounted for in the benchmarking roll-forward model procedure. We consider step changes in prudent and efficient opex are implicitly captured in the time trend coefficient from the econometric models, which is used in the roll-forward process. The time trend coefficient is positive, meaning that a percentage increase in time (years) leads to a percentage increase in opex. This indicates negative gross productivity growth over the relevant benchmarking period. This is at odds with economic expectations for positive productivity growth over time due to technological progress and other factors. We consider that measured positive time trend coefficient therefore in part reflects the increase in regulatory obligations over time, the costs for which we allow via forecasts for step changes.

In addition, we do not consider a step change can be viewed in isolation. Other DNSPs have also incurred increases in costs for step changes (including for other regulatory obligations), thus negatively impacting their opex efficiency scores.

Our preferred approach to reflect the costs of Evoenergy's vegetation management step change is to augment our vegetation management OEF adjustment, as discussed above.

Base year opex to which modelled efficient opex is compared

We have also considered Evoenergy's actual base year opex to which estimated efficient opex in the base year is compared in the derivation of the efficiency gap. In particular we

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89 Evoenergy, *Appendix 2.1 Base year efficiency*, January 2023, pp. 30–32.

have considered whether and which adjustments to make to actual base year opex for the purpose of this benchmarking comparison. These are discussed below.

After making the adjustments discussed below, the adjusted base year actual opex (plus capitalised corporate overheads) used to calculate the efficiency gap is $69.1 million ($RY2021). This is calculated in our benchmarking roll-forward model, and reflects the application of the opex price deflator to nominal opex (with the adjustments outlined below) plus capitalised corporate overheads.

Adjustments to actual base year opex for movements in provisions, demand management innovation allowance, large feed in tariff (LFiT) scheme

In its proposal in the context of presenting its efficiency gap calculation, consistent with the adjustments it proposed for base opex in its opex model, Evoenergy made three adjustments to actual base year opex of $60.3 million ($RY2021) (to which modelled estimated efficient opex is compared). These were to remove:

- costs for the DMIA, ($0.4 million ($RY2021))
- administrative costs of the large feed in tariff (LFiT) scheme ($0.5 million ($RY2021))
- movements in provisions ($0.7 million ($RY2021)).[90]

These resulted in an adjusted base year opex of $58.6 million ($RY2021).

The basic principle we have adopted in this assessment is that the comparison of actual opex in the base year to estimated efficient opex in the base year should be done on a like-with-like basis.

In this light, consistent with Evoenergy's proposal, we have removed movements in provisions from actual base year opex in the comparison to modelled efficient opex. We consider movements in provisions should be removed as these amounts, both positive and negative, would generally net out to zero over the benchmarking periods. In this regard, movements in provisions are effectively zero in modelled efficient base year opex.

In relation to the costs of the DMIA and LFiT scheme, however, we consider these should remain in actual base year opex. This is because these are positive amounts that would be reported in the Economic Benchmarking RIN data series and therefore reflected in the opex series used for benchmarking. As a result these costs are therefore included in estimated efficient opex to which actual base year opex is compared.

In summary, we have decided to do the following in relation to adjustments to actual base year opex used in deriving the efficiency gap:

- retain DMIA and LFiT scheme costs
- remove movements in provisions.

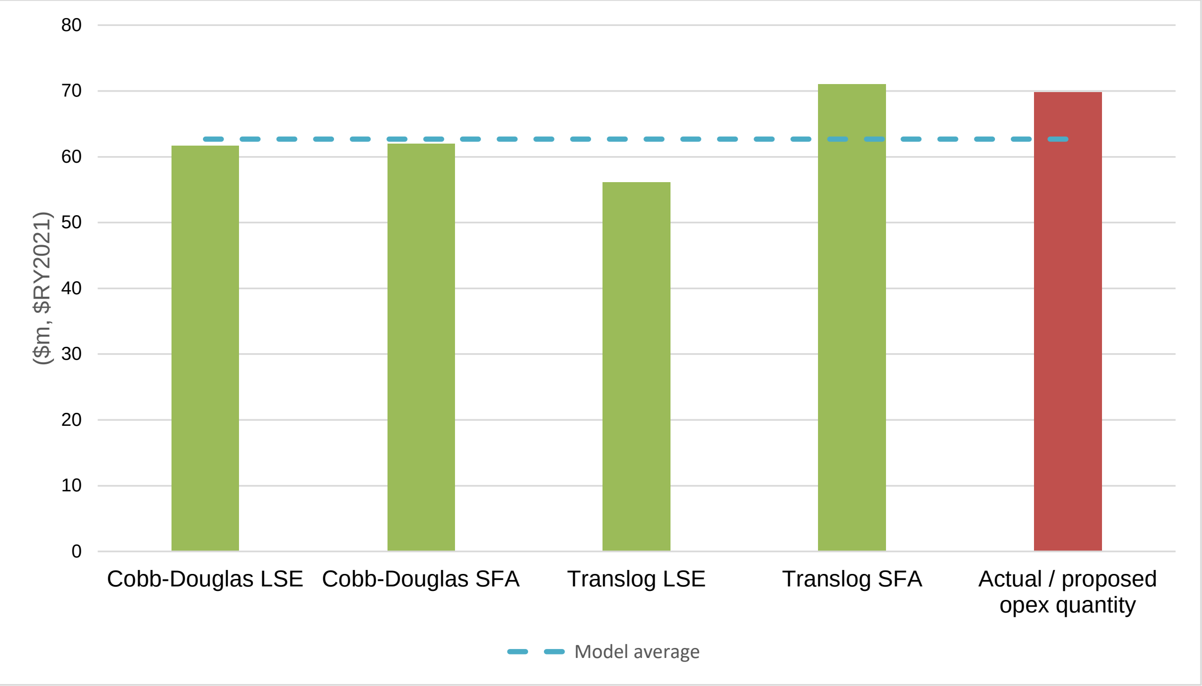
90 Evoenergy, *Attachment 2 Operating expenditure*, 31 January 2023, pp. 18–19; Evoenergy, *Appendix 2.1 Base year efficiency*, January 2023, p. 33.

Calculation of efficiency gap between base year actual opex and estimated efficient base year opex

The results of the above discussion of estimated efficient base year opex and actual base year opex for Evoenergy are set out in Figure 6.9 for the 2006–21 (long) benchmarking period and in Figure 6.10 for the 2012–21 (short) benchmarking period using results from the *2022 Annual Benchmarking Report* updated to take into account Evoenergy's updated RMD and the AER's approach to addressing capitalisation differences in benchmarking.

In Figure 6.9, our estimates of efficient network services opex plus capitalised corporate overheads (which includes adjustments for OEFs) in the base year are shown in green (with an average of $62.2 million ($RY 2021)). Evoenergy's actual network services opex plus capitalised corporate overheads in the base year of 2021–22 is shown in red ($69.1 million ($RY 2021)). Our estimated efficient base year opex plus capitalised corporate overheads (the blue dashed line), derived from the results in our econometric opex cost function models and application of the benchmarking roll-forward model, is therefore $6.9 million ($RY 2021), or 10.0% below Evoenergy's actual network services opex plus capitalised corporate overheads.

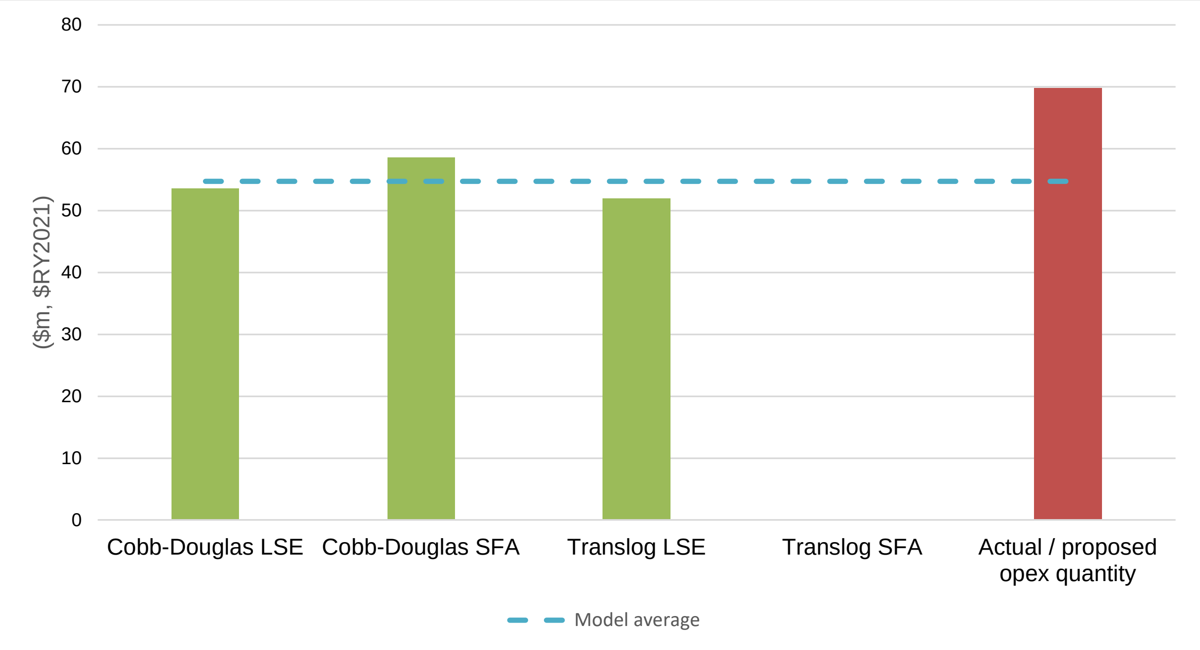
Figure 6.9 Estimates of efficient network services opex using data over the 2006–21 period ($ million, RY21)



Source: Quantonomics, *Benchmarking results for the AER – Distribution*, November 2022; AER analysis.

Similarly, in Figure 6.10 our estimated efficient network services opex plus capitalised corporate overheads (which includes adjustments for material OEFs) in the base year over the period 2012–21 are shown in green (with an average of $54.3 million ($RY 2021)), against Evoenergy's actual network services opex plus capitalised corporate overheads in the base year of 2021–22 again shown in red ($69.1 million ($RY 2021)). Our average estimate (the blue dashed line) is $14.8 million ($RY 2021), or 21.4% below Evoenergy's actual opex plus capitalised corporate overheads.

Figure 6.10 Estimates of efficient network services opex using data over the 2012–21 period ($ million, RY 2021)



Source: Quantonomics, *Benchmarking results for the AER – Distribution*, November 2022; AER analysis.

Note: We exclude the efficiency score for the SFA TLG model for Evoenergy as it does not satisfy the monotonicity requirement (as discussed above).

Across the two benchmarking periods, the average difference between our estimates of efficient network services opex plus capitalised corporate overheads in the base year and Evoenergy's actual network services opex plus capitalised corporate overheads in the base year is $10.8 million ($RY 2021), which is 15.7% below Evoenergy's actual base year network services opex plus capitalised corporate overheads. Whilst this represents the efficiency gap in relation to opex plus capitalised corporate overheads, we also consider this translates as the efficiency gap in opex alone (i.e. exclusive of capitalised corporate overheads). This assumes the efficiency of opex and capitalised corporate overheads is similar, which we consider reasonable. As discussed in section 6.4.1.2.5, we have drawn on this efficiency gap to inform an efficiency adjustment that is applied to Evoenergy's opex (exclusive of capitalised corporate overheads).

6.4.1.2.4 Evoenergy's argument on limitations of benchmarking results

As outlined above, Evoenergy submitted that its opex in the base year should not be considered materially inefficient. It formed this view based on its understanding of the limitations of the AER's benchmarking, as well as by making the adjustments outlined above (incorporating prudent and efficient step changes into the benchmarking, correcting MD data, accounting for OEFs and taking into account the material impacts of differences in capitalisation practices).[91] Importantly in terms of the benchmarking limitations, Evoenergy considered that while the benchmarking results suggest its opex in the proposed base year is materially inefficient, that the AER should not view these results as 'highly precise or

[91] Evoenergy, *Attachment 2 Operating Expenditure*, January 2023, p. 20.

determinative' given the associated limitations, but rather consider the estimates of efficient opex from applying the benchmarking results are 'indicative at best' and should not be used to make an efficiency adjustment.[92]

Evoenergy's proposal detailed what it considered were many shortcomings and limitations associated with the AER's benchmarking approach.[93] At a high level these limitations can be summarised as:

- Concerns in relation to the econometric opex cost function models that it considered make the results unreliable and in particular:
  - the translog models continue to suffer from monotonicity violations and in this context there are differences in efficiency scores between the models
  - the estimated output weights from the models are sensitive to the benchmarking periods, the models used and are influenced more heavily by the Ontarian DNSP data than the Australian DNSPs
  - questions around whether to use translog models versus the Cobb-Douglas models
  - the models are highly dependent on data from overseas DNSPs which operate in very different circumstances to Australian DNSPs
  - the models fail to account for efficient opex-capex substitution choices.
- Concerns in relation to OEF differences between DNSPs which it considered are not properly accounted for and in particular:
  - the econometric opex cost function models include limited OEF explanatory variables to allow like-with-like comparisons and produce reliable estimates
  - the use of post-modelling OEF adjustments are likely to produce unreliable estimates of efficiency and potentially misidentify comparator DNSPs.

In forming our draft decision, we have considered these benchmarking limitations, including with the expert input of our benchmarking consultant, Quantonomics. Quantonomics' views and responses to the benchmarking limitations raised by Evoenergy are set out in a memorandum also published with this draft decision.[94] Further, in Table 6.7 we summarise the limitations Evoenergy raised and our responses, drawing on the expert advice of Quantonomics.

In summary we consider that while our benchmarking tools are not perfect, this does not limit us from using them in revenue determination processes to assess the efficiency of opex in a proposed base year. Particularly important in this regard is that we only apply results where we consider they reliably inform our overall base year opex efficiency assessment e.g. by removing the results of econometric opex cost function models that do not meet the monotonicity requirements. Further, using a 0.75 comparison point, adjusted for OEFs, instead of 1.0, builds in a degree of conservativeness in part reflecting that we acknowledge our benchmarking tools are not exactly precise or perfect tools.

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92 Evoenergy, *Appendix 2.1 Base year efficiency*, January 2023, p. 37.

93 Evoenergy, *Appendix 2.1 Base year efficiency*, January 2023, pp. 5–6, 35–37.

94 Quantonomics, *Memorandum Evoenergy – Benchmarking limitations*, September 2022.

We also acknowledge that there are issues of judgement involved in developing and applying a benchmarking approach. Further, we acknowledge that there is scope for future benchmarking development work to ensure it continually improves.

Table 6.7 Economic benchmarking limitations and draft decision responses

Limitation	AER response to limitation raised
Econometric opex cost function modelling limitations which Evoenergy considers make the results unreliable	
The translog models continue to suffer from monotonicity violations – which are sensitive to the time period and businesses impacted – and if not included impact the average efficiency scores across all models.	The translog model efficiency score results are not used for a DNSP when there are monotonicity violations for a majority of observations for the DNSP or when the majority of Australian DNSPs have violations. We consider it appropriate to not use the results of models that do not produce valid, economically principled, results. Further, to consider what the average efficiency scores would have been if these results were included is not a reasonable comparison given we do not consider the results with excessive monotonicity violations are valid. A possible approach for addressing the loss of a translog model if there are monotonicity violations is by using a 'hybrid' translog model. The hybrid model removes some of the cross-product and squared output coefficients (which may be correlated) and to date has shown some promise in terms of minimising / removing the monotonicity violations. While this approach has shown some promise, further work is required to determine if it is a solution that performs well over time and which hybrid model would be best utilised, including from an economic principle perspective.
The suggestion that the translog models should be used over the Cobb-Douglas models as a result of the joint significance of the higher order terms in the translog model (via the Wald tests).	The use of average efficiency scores of more than one benchmarking model can help to ensure that efficiency assessment is not too dependent on one model specification given they have different strengths and weaknesses and potential specification errors. In that regard, there are several criteria that can be used when evaluating models and which demonstrate their strength and weaknesses. Joint significance is one test, but others include goodness-of-fit and the meaningful economic interpretation of parameters. Considering these collectively, we do not consider the translog model is unambiguously better than the Cobb-Douglas model. The translog model has the advantage that joint significance tests generally suggest that the additional variables added to the model (relative to the Cobb-Douglas models) are significant. However, the Cobb-Douglas model is more parsimonious and performs equally in terms of goodness of fit. The Cobb-Douglas model also does not encounter monotonicity issues.
The efficiency scores and output weights from the models are highly variable depending on the period used, the models used and are heavily influenced by the international data.	The variations in efficiency scores and output weights indicate that the use of different model specifications and sample periods will produce slightly different results, which is why they are examined and averages considered. The practice of averaging efficiency scores and output weights across models mitigates the concerns about the variability of these results. It is also noted that there is broad similarity in efficiency score results across the models for DNSPs.
The models are highly dependent on international data for DNSPs (e.g. Ontarian data makes up 52% of the sample) which operate in very different circumstances to Australian DNSPs and the country dummy variables do not control for these differences.	International DNSP data is not included as means of international benchmarking, both in terms of intention and effect. The inclusion of international data has an important role in ensuring that there is a sufficient number of observations, and also sufficient diversity among the DNSPs included, to provide reliable estimation of the models and improve the precision of the estimates of individual parameters of interest (e.g. output elasticities and the undergrounding effect). It is appropriate to use data from international DNSPs as they carry out the same electricity distribution functions and use common technology, which determines the shape of the opex cost function. Further, exploratory work undertaken by our previous consultant, Economic Insights, showed that even when the weight given to the Australian observations was around half the observations (using an appropriate modelling technique) there was only a small effect on estimated efficiency scores relative to the modelling with the unweighted observations.
The models fail to account for opex-capex substitution and hence DNSPs that make allocatively efficient choices to undertake more maintenance work rather than replacing assets appear less efficient.	While the current econometric opex cost function models do not include a capital input variable, as the omitted capital input is closely correlated with the outputs in the models, and has a substituting relationship with opex then to some extent its impact is accounted for in the measurement of opex efficiency. We referenced this in our recent final guidance note on how we will address capitalisation differences. Further, future development work has been noted in the final guidance note on how we will address capitalisation differences in terms of estimating the degree of substitution between capital and non-capital inputs in a long-run opex cost function model, but various data and other challenges were noted with this work.

Limitation	AER response to limitation raised
Operating environment factor differences which Evoenergy consider make the results unreliable	
The econometric opex cost function models include limited explanatory variables for operating environment differences.	Different procedures can be used to control for the influence of OEFs in benchmarking analysis: 1. Ex-ante adjustment of data 2. In the econometric opex cost function models 3. Ex-post adjustments after the econometric analysis has been undertaken. There are advantages and disadvantages with each of these approaches, and benchmarking exercises need to apply fit-for-purpose approaches in the prevailing circumstances. This has been the approach adopted by the AER. The econometric opex cost function models currently make pre-modelling adjustment to address OEF differences e.g. to remove opex associated with metering, connection and other services within standard control services where there are known differences. The models also include variables which account for the percentage of underground cables in total circuit length where there can be differences between DNSPs, customer / network density via the output specification and static differences between jurisdictions (via country dummies). Therefore, ex-ante and econometric opex cost function adjustments are made where this has been possible. While ideally all OEF differences would be included within the econometric opex cost function models, because this enables their statistical significance to be tested and their effect to be estimated using sample data, this is not always possible. For practical reasons ex-post modelling adjustments are also used reflecting the difficulties in developing comparable OEF data, including for overseas DNSPs (if variables were to be included in the econometric opex cost function model) and given the nature of the OEF differences is that their quantification relies on detailed jurisdiction-specific information. As outlined above, the AER makes several ex-post modelling OEF adjustments e.g. for the higher operating costs of maintaining sub-transmission assets and for differences in vegetation management requirements. We have also noted that future development work would include refining the quantification of material OEFs (which we have considered as a part of this draft decision as relevant to Evoenergy).
The ex-post adjustments for OEFs after the econometric analysis has been undertaken is likely to produce unreliable estimates of efficiency as the efficiency scores produced by the modelling are affected by non-comparable data that cannot be corrected post-modelling. As a result, the comparator group of DNSPs obtained from the benchmarking may be incorrect.	This argument is not adequately established as there has been no evidence provided that inclusion of the OEF differences as variables in the econometric analysis, were it feasible to do so, would yield a material difference to efficiency score from their present use in post-modelling adjustment of efficiency. In any case, at present it is not feasible to do so due to lack of comparable data for overseas DNSPs.

Note: The AER's responses to the benchmarking limitations raised by Evoenergy have been informed by the expert input of our benchmarking consultant, Quantonomics as set out in a memorandum also published with this draft decision.

6.4.1.2.5 *Efficiency adjustment to Evoenergy's base year opex*

Taking the above analysis into account, including that we do not agree with Evoenergy's arguments in relation to benchmarking limitations, we have concluded on balance that Evoenergy's actual base year opex is not at a level that is consistent with what an efficient service provider operating in Evoenergy's circumstances would require to deliver its network services.

Given the results from our benchmarking analysis and the conservatism built into our benchmarking approach, including the use of 0.75 as the efficiency benchmark and accounting for material OEFs, we consider that Evoenergy's base year opex is materially inefficient. Consequently, to determine our alternative estimate of base opex we have drawn on our efficiency gap analysis to make an efficiency adjustment to Evoenergy's base year opex to establish a level of opex that we consider reflects an efficient distributor's opex.

The size of the efficiency adjustment for Evoenergy suggested by the benchmarking results adjusted to take account of the relevant OEFs is 15.7%, as indicated in the analysis above.

However, we have incorporated a glide path to transition Evoenergy from its current opex levels to the more efficient opex level that we consider is consistent with the above analysis. Consistent with our most recent application of the benchmarking results for this purpose (for Jemena in its 2021–26 decision[95]), we have transitioned to the efficient lower cost base via a linear transition path to the efficient opex over the next regulatory control period. This recognises it will take time and involve costs for management to implement the required programs over the next regulatory control period to realise opex reductions. This contrasts with moving straight to what we consider is efficient base opex based on our benchmarking results.

In practice this means a total efficiency adjustment over the period of $30.8 million ($2023–24), comprising adjustments of: year 1 -$2.1 million ($2023–24), year 2 -$4.1 million ($2023–24), year 3 -$6.1 million ($2023–24), year 4 -$8.2 million ($2023–24) and year 5 -$10.3 million ($2023–24), as set out in the opex model. This results in an effective 5-year efficiency adjustment, as a percentage of our alternative estimate of base year opex after base adjustments (discussed below), of 9.4%.

We consider that the glide path provides for a prudent, practicably achievable target that will allow Evoenergy to achieve cost efficiency while at the same time maintaining the quality, reliability, security and safety of services over the next regulatory control period.

6.4.1.3 Adjustments to base year opex

Evoenergy proposed a total adjustment to its base opex of $0.8 million ($2023–24) or $4.2 million ($2023–24) over the 5 years of the next regulatory control period. These were to remove costs for the administration of the LFiT scheme and to add a final year increment.[96]

We have considered these proposed adjustments and have adjusted our alternative estimate of opex in the base year by –$1.0 million ($2023–24) or –$5.0 million ($2023–24) over 5 years to:

- subtract $0.6 million ($2023–24) to remove costs for the administration of the LFiT scheme. This decreases our alternative estimate of total opex by $2.9 million ($2023–24) over 5 years. We explain this adjustment in section 6.4.1.3.1.
- subtract $0.4 million ($2023–24) for the change in opex between 2021–22 and 2023–24 (final year increment). This decreases our alternative estimate by $2.1 million ($2023–24) over the 5 years. We explain this adjustment in section 6.4.1.3.2.

95 AER, *Final Decision - Jemena determination 2021–26 - Attachment 6 – Operating Expenditure*, April 2021, pp. 36–37.

96 Evoenergy, *Attachment 2 Operating Expenditure*, January 2023, p. 18.

The key differences between our total adjustment and that of Evoenergy is that we have applied a different final year increment.

6.4.1.3.1 Administration of Large-Feed-in-Tariff scheme

Evoenergy reduced its base year opex by $0.6 million ($2023–24) ($2.9 million over the next regulatory control period), to remove the costs it incurred to administer the ACT Government's LFiT. Under the *Electricity Feed-in (Large-scale Renewable Energy Generation) Act 2011*, Evoenergy is able to pass on to electricity customers the 'reasonable costs' it incurs to administer the LFiT. Evoenergy, therefore, removed these costs from its base year opex to ensure that it only recovers these costs from network users once.

We have made the same adjustment in our alternative estimate.

6.4.1.3.2 Final year increment

Our standard practice to calculate final year opex is to add the estimated change in opex between the base year (2021–22) and the final year (2023–24) of the current (2019–24) regulatory control period to the base year opex amount.[97]

We have included –$2.1 million ($2023–24) for the final year increment in our alternative estimate, which is $9.3 million ($2023–24) lower than Evoenergy's proposed amount of $7.2 million ($2023–24). The variance between our alternative estimate and Evoenergy's proposal arises because Evoenergy used the equation set out in the *Expenditure forecast assessment guideline* to estimate its opex in 2023–24, whereas we have applied the rate of change to base year opex to estimate opex in 2023–24.

As noted in the *Expenditure forecast assessment guideline*, the EBSS requires an estimate of actual opex for the final year, which we do not know at the time of the final determination. Expressing estimated final year expenditure in the form set out in the *Expenditure forecast assessment guideline* allows the distributor to retain incremental efficiency gains made after the base year through the EBSS carryover. The business is rewarded by the EBSS for the efficiency gain reflected in the level of opex used to forecast opex.

In this context, we are not usually concerned if the estimate of final year opex is incorrect. This is because if the same estimate of opex is used to both forecast opex and calculate EBSS carryovers allowed, the revenue will be similar. A lower estimate of final year opex will produce a lower opex forecast but higher EBSS rewards.

However, in this case we are not applying the negative EBSS carryovers Evoenergy has accrued in the current regulatory control period (see Attachment 8 of this draft decision). Consequently, our concern when we estimate final year opex is to ensure it reasonably reflects the efficient costs of a prudent operator. To this end, we have applied a forecast rate of change to base opex. This approach is consistent with other decisions we have made where we have not applied the EBSS carryovers accrued in the current period, including our decision for Evoenergy's (then ActewAGL's) 2014–19 regulatory control period.[98]

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[97] AER, *Expenditure forecast assessment guideline for electricity distribution,* August 2022, pp. 24–25.

[98] AER, *ActewAGL distribution determination - Attachment 7 – Operating expenditure*, April 2015, p. 264.

6.4.2 Rate of change

Having determined an efficient starting point, or base opex, we trend it forward to account for the forecast growth in prices, output and productivity. We refer to this as the rate of change.[99]

Evoenergy broadly applied our standard approach to forecasting the rate of change. In its proposed opex forecast, it used:

- **Price growth:** input price weightings of 59.2% for labour and 40.8% for non-labour to forecast price growth. It forecast labour price growth using BIS Oxford Economics' wage price index (WPI) growth forecasts. It did not add the legislated superannuation guarantee increases to its labour price growth forecasts.[100]
- **Output growth:** the weights based on our 4 econometric models, consistent with our most recent determinations. However, Evoenergy did not use the output weights from our *2022 Annual benchmarking report*. It recalculated the output weights to reflect revisions it considers should be made to its historic ratcheted maximum demand.[101]
- **Productivity growth:** our 0.5% per year productivity growth forecast.

The rate of change proposed by Evoenergy contributed $14.3 million ($2023–24), or 3.8%, to its total opex forecast of $390.1 million ($2023–24). This equates to opex increasing by 1.4% each year. We have included a rate of change that increases opex by 1.0% each year in our alternative estimate.

We compare both forecasts in Table 6.8, and set out the reasons for the differences below.

Table 6.8 Forecast rate of change (%)

	2024-25	2025-26	2026-27	2027-28	2028-29
Evoenergy's proposal					
Price growth	0.6	0.6	0.4	0.3	0.5
Output growth	1.2	1.5	1.4	1.4	1.5
Productivity growth	0.5	0.5	0.5	0.5	0.5
Overall rate of change	**1.3**	**1.5**	**1.3**	**1.2**	**1.5**
AER alternative estimate – draft decision					
Price growth	0.6	0.8	0.5	0.4	0.5
Output growth	0.7	0.8	0.9	1.2	1.2
Productivity growth	0.5	0.5	0.5	0.5	0.5
Overall rate of change	**0.8**	**1.0**	**0.9**	**1.1**	**1.3**
Difference	**–0.5**	**–0.5**	**–0.4**	**–0.1**	**–0.2**

Source: Evoenergy, *SCS opex model,* 31 January 2023: AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

99 AER, *Expenditure forecast assessment guideline for electricity distribution*, August 2022, pp. 25–26.

100 Evoenergy, *Attachment 2 Operating Expenditure*, January 2023, p. 22.

101 Evoenergy, *Attachment 2 Operating Expenditure*, January 2023, pp. 22–24.

6.4.2.1 Forecast price growth

Evoenergy proposed average annual price growth of 0.5%, which increased its total opex forecast by $5.3 million ($2023–24). The average annual real price growth we used in our alternative estimate was 0.6%. This increases our total opex alternative estimate by $5.1 million ($2023–24).

Both we and Evoenergy forecast price growth as a weighted average of forecast labour price growth and non-labour price growth:

- Evoenergy used the WPI growth forecasts for the electricity, gas, water and waste services (utilities) industry in the ACT from its consultant BIS Oxford Economics to forecast labour price growth.[102] In our alternative estimate, we have averaged the WPI growth forecasts from BIS Oxford Economics with newer forecasts from KPMG. We have also added the legislated superannuation guarantee increases because these are not reflected in the WPI.
- Both we and Evoenergy applied a forecast non-labour real price growth rate of zero.[103]
- Both we and Evoenergy have applied the same input price weights to account for the proportions of opex that is labour and non-labour, 59.2% and 40.8% respectively.[104]

Consequently, the key differences between our real price growth forecasts and Evoenergy's are that we have updated our labour price growth forecast to include newer forecasts, and we have accounted for the legislated superannuation guarantee increases.

Table 6.9 compares our forecast labour price growth with Evoenergy's proposal.

Table 6.9 Forecast labour price growth (%)

	2024–25	2025–26	2026–27	2027–28	2028–29
Evoenergy's proposal					
BIS Oxford Economics	1.1	0.9	0.8	0.5	0.8
Superannuation guarantee increases	–	–	–	–	–
Forecast labour price growth	**1.1**	**0.9**	**0.8**	**0.5**	**0.8**
AER's alternative estimate					
KPMG	0.1	0.6	0.8	0.9	1.0
BIS Oxford Economics	1.1	0.9	0.8	0.5	0.8
Average	0.6	0.8	0.8	0.7	0.9
Superannuation guarantee increases	0.5	0.5	–	–	–
Forecast labour price growth	**1.1**	**1.3**	**0.8**	**0.7**	**0.9**
Overall difference	**0.0**	**0.3**	**0.0**	**0.2**	**0.1**

Source: Evoenergy, *Attachment 2 Operating Expenditure*, January 2023, p. 22; KPMG, *WPI forecast report*, August 2023, p. 38; AER analysis.

Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

[102] Evoenergy, *Regulatory proposal, Attachment 2 Operating Expenditure*, January 2023, pp. 21–22.

[103] Evoenergy, *Attachment 2 Operating Expenditure*, January 2023, p. 22.

[104] Evoenergy, *Attachment 2 Operating Expenditure*, January 2023, p. 22.

6.4.2.2 Forecast output growth

Evoenergy proposed average annual output growth of 1.4%, which increased its proposed opex forecast by $14.1 million ($2023–24). We have forecast average annual output growth of 0.9%. This increases our alternative estimate of total opex by $6.6 million ($2023–24).

We and Evoenergy have both forecast output growth by:

- calculating the forecast growth rates for 3 outputs (customer numbers, circuit line length and ratcheted maximum demand).[105] However, we have included lower forecast growth in circuit length and ratcheted maximum demand than Evoenergy
- calculating 4 weighted average overall output growth rates using the output weights from the 4 econometric opex cost function benchmarking models in our *2022 Annual benchmarking report*, updated to reflect revised historic ratcheted maximum demand values provided by Evoenergy[106]
- averaging the 4-model specific weighted overall output growth rates.[107]

We discuss these below.

6.4.2.2.1 Forecast growth of the individual output measures

We are satisfied that Evoenergy's forecast customer numbers growth reasonably reflect a realistic expectation. However, we are not satisfied that Evoenergy's forecast of the growth in circuit length and ratcheted maximum demand reflect a realistic expectation. Specifically:

Customer numbers: Evoenergy proposed forecast residential and low voltage commercial customer numbers based on population growth projections. It proposed high voltage commercial customer forecasts based on historical trends, which it supplemented with information on planned and expected future connections.[108] We have reviewed these forecasts and found them to be in line with historic average growth levels.

Circuit length: Evoenergy included average annual circuit length growth of 1.2% in its opex model.[109] However, this forecast does not reflect the circuit length forecasts Evoenergy included in its reset regulatory information notice (RIN), which forecast growth of 1.0% each year.[110] We have used the circuit length forecasts Evoenergy provided in its reset RIN in our alternative estimate opex model.

Ratcheted maximum demand: Evoenergy included average annual ratcheted maximum demand growth of 1.7% in its opex model.[111] For the reasons outlined in Attachment 5, we are not satisfied that Evoenergy's maximum demand forecasts reasonably reflect a realistic expectation.[112] We have included average forecast ratcheted maximum demand growth of

105 Evoenergy, *Operating Expenditure*, January 2023, p. 22.

106 Evoenergy, *Operating Expenditure*, January 2023, pp. 23–24.

107 Evoenergy, *Operating Expenditure*, January 2023, p. 22.

108 Evoenergy, *Appendix L Energy and customer number forecasts*, January 2023, p. 17.

109 Evoenergy, *Attachment 2 Operating Expenditure*, January 2023, p. 22.

110 Evoenergy, *RIN Appendix 2 - Final RIN - Workbook 1 - Forecast data*, February 2023, table 3.5.1.

111 Evoenergy, *Attachment 2 Operating Expenditure*, January 2023, p. 22.

112 NER, cl. 6.5.6(c)(3).

0.6%. This reflects the growth in our forecast of maximum demand measured at the zone substation in MVA.[113] Our standard approach is to use the equivalent forecast measured at the transmission connection point in MW, which is the measure of demand we use in our annual benchmarking. However, we don't have such a forecast available to us. We consider that the growth in forecast maximum demand, measured at the zone substation in MVA, is the best available estimate available to us. We encourage Evoenergy to provide a revised forecast of maximum demand in its revised proposal that addresses the concerns we have outlined in Attachment 5.[114]

6.4.2.2.2 Output weights

The output weights that we have used in our alternative estimate are set out in Table 6.10 These values are different to both those in our 2022 *Annual benchmarking report*, and in Evoenergy's proposal.

Evoenergy recently submitted revised non-coincident summated raw system annual maximum demand data. The opex cost function regression results in our *2022 Annual benchmarking report* were calculated using the maximum demand data that Evoenergy previously submitted. We have rerun our opex cost function using the updated maximum demand data. We have used the new opex cost function regression results to derive the output weights in Table 6.10, which we have used in our alternative estimate.

Table 6.10 Output weights (%)

	Cobb-Douglas SFA	Cobb Douglas LSE	Translog LSE	Translog SFA
2022 Annual benchmarking report				
Customer numbers	43.1	60.9	45.1	47.6
Circuit length	10.8	15.7	17.2	8.4
Ratcheted maximum demand	46.1	23.4	37.6	43.9
Evoenergy's proposal				
Customer numbers	46.1	61.0	45.6	52.8
Circuit length	11.3	15.7	17.2	8.6
Ratcheted maximum demand	42.6	23.2	37.3	38.6
AER alternative estimate				
Customer numbers	46.7	60.7	45.7	54.5
Circuit length	10.8	15.8	17.3	5.0
Ratcheted maximum demand	42.5	23.4	37.0	40.5

Source: Quantonomics, Economic Benchmarking Results for the Australian Energy Regulator's 2022 DNSP Annual Benchmarking Report, 17 November 2022, pp. 137–139; Evoenergy, *Attachment 2 Operating Expenditure*, January 2023, p. 24; AER analysis.
Note: Amounts of '0.0' and '–0.0' represent small non-zero values and '–' represents zero.

[113] Specifically, non-coincident summated system annual maximum demand measured at the zone substation in MVA with a probability of exceedance of 50%.

[114] Specifically, non-coincident summated system annual maximum demand measured at the transmission connection point in MW with a probability of exceedance of 50%.

We will publish our *2023 Annual benchmarking report* in late November 2023. In our final decision, we will update our output growth forecasts to reflect the output weights in the *2023 Annual benchmarking report*. Full details of our approach to forecasting output growth are set out in our opex model, which is available on our website.

6.4.2.3 Forecast productivity growth

Evoenergy proposed average productivity growth of 0.5% per year. We have forecast the same average productivity growth of 0.5% per year, which reflects our standard approach.[115] This decreases our alternative opex estimate by $3.8 million ($2023–24) over the regulatory control period, which is similar to the decrease proposed by the Evoenergy of $5.1 million ($2023–24).

6.4.3 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 / opex trade-offs. As we explain in the *Expenditure forecast assessment guideline* for electricity distributors, 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.[116]

Evoenergy's proposal included 3 step changes totalling $31.2 million ($2023–24), or 8.0% of its proposed total opex forecast. These are shown in Table 6.11 along with our alternative estimate for the draft decision, which is to include step changes totalling $29.4 million ($2023–24), being $1.7 million ($2023–24) lower than Evoenergy's proposal. Our lower alternative estimate is due to our lower alternative estimate for Evoenergy's proposed CER integration step change. We discuss this below.

Table 6.11 Proposed step changes ($million, 2023–24)

Step change	Evoenergy's proposal	AER's alternative estimate	Difference
Insurance	5.0	5.0	0.0
Cyber security	14.6	14.6	–
CER integration	11.6	9.9	–1.8
Total step changes	**31.2**	**29.4**	**–1.7**

Source: AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

6.4.3.1 Insurance step change

Evoenergy proposed a step change of $5.0 million ($2023–24) for an increase in insurance premiums over the 2024–29 regulatory control period.[117] This relates to the rising costs of insurance premiums above the base year, which Evoenergy considered cannot continue to

115 AER, *Forecasting productivity growth for electricity distributors*, March 2019.

116 AER, *Expenditure forecast assessment guideline for electricity distribution*, August 2022, p. 26.

117 Evoenergy, *Attachment 2 Operating expenditure*, January 2023, p. 27.

be absorbed into an efficient and prudent operating envelope.[118] Our draft decision is to include a forecast of $5.0 million ($2023–24) for the proposed insurance premiums step change in our alternative estimate.

We have included this step change in our alternative estimate as we consider the insurance premium increases results in forecast expenditure that is likely to be prudent and efficient.

Table 6.12 Insurance step change ($million, 2023–24)

	2024–25	2025–26	2026–27	2027–28	2028–29	Total
Evoenergy’s proposal	0.6	0.9	1.0	1.2	1.3	5.0
AER draft decision	0.7	0.9	1.0	1.2	1.3	5.0
Difference	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Source: Evoenergy, *Attachment 2 Operating expenditure*, January 2023, p. 27. AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

Evoenergy noted that insurance premiums have increased substantially over the current regulatory control period, driven by increased climate events, cyber-attacks, and general macroeconomic conditions.[119] Evoenergy engaged Marsh to provide insurance premium cost forecasts for the full spectrum of their insurance program, with Marsh expecting the trend of premium increases to continue over the 2024–29 regulatory control period.[120]

Evoenergy calculated the step change amount as the difference between the cost forecasts prepared by Marsh and insurance costs in the base year (2021–22). Evoenergy considers these costs are expected to be above the calculated base opex amount and rate of change.[121]

We recently engaged Taylor Fry to assess the prudency and efficiency of forecast insurance premiums for our 2023–28 ElectraNet and Transgrid revenue determinations. We consider Evoenergy's forecast insurance premiums, prepared by Marsh, are consistent with Taylor Fry's expectation of future premiums in that context, given prevailing market conditions. On this basis, we consider Evoenergy’s forecast insurance costs are likely to be reasonable.

Our assessment considers the rate of change forecast, which includes an allowance for non-labour price growth of consumer price index (CPI), which covers potential increases in costs like insurance premiums. We expect some non-labour components in opex will increase by more than CPI and some less than CPI. To the extent that insurance premiums rise by more than CPI, we expect this will to an extent be offset by other non-labour costs rising by less than CPI. We note, however, that there may be specific circumstances where it is appropriate to consider increasing costs of individual cost categories, particularly where they represent a material proportion of opex.

118 Evoenergy, *Attachment 2 Operating expenditure*, January 2023, p. 27.

119 Evoenergy, *Attachment 2 Operating expenditure*, January 2023, p. 27.

120 Evoenergy, *Appendix 2.3 Insurance premium step change business case*, January 2023, p. 6.

121 Evoenergy, *Appendix 2.3 Insurance premium step change business case*, January 2023, p. 6.

Evoenergy's insurance premium step change of $5.0 million ($2023–24) represents 1.5% of our forecast alternative estimate of total opex. We consider this represents a material proportion of opex that is not captured in base opex or the forecast rate of change. Accordingly, we have included this step change in our alternative estimate.

6.4.3.2 Security of Critical Infrastructure step change

Our draft decision is to include a placeholder amount of $14.6 million ($2023–24) for the Security of Critical Infrastructure step change in our alternative estimate of total forecast opex for the draft decision. This is consistent with the costs proposed by Evoenergy, and reflects that we are satisfied that an uplift in cyber security expenditure is likely to be prudent in the context of an evolving threat landscape and regulatory obligations.

However, due to circumstances outside the control of Evoenergy relating to the sharing of confidential information, we have been limited in our ability to assess this step change for the draft decision. Therefore, we will continue to work with Evoenergy in preparing its revised proposal, and undertake further assessment before making our final decision on prudent and efficient expenditure in relation to the security of critical infrastructure step change.

Table 6.13 Security of Critical Infrastructure step change ($million, 2023–24)

	2024–25	2025–26	2025–26	2027–28	2028–29	Total
Evoenergy’s proposal	2.9	2.9	2.9	3.0	2.9	14.6
AER draft decision	2.9	2.9	2.9	3.0	2.9	14.6
Difference	–	–	–	–	–	–

Source: Evoenergy, *SCS opex model,* 31 January; AER analysis.
Note: Numbers may not add up to totals due to rounding: Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

6.4.3.3 Consumer Energy Resources (CER) integration step change

Evoenergy proposed a step change of $11.6 million ($2023–24) over the 2024–29 regulatory control period for CER integration.[122] This expenditure relates to supporting the energy transition and integrating an increased volume of customers with consumer energy resources into its network.[123] Our draft decision is to include $9.9 million ($2023–24) for this step change in our alternative estimate of forecast opex. We are satisfied this amount results in forecast expenditure that is likely to be prudent and efficient for Evoenergy’s CER strategy.

Table 6.14 CER integration step change (million, $2023–24)

	2024–25	2025-26	2026–27	2027–28	2028–29	Total
Evoenergy’s proposal	2.6	2.2	2.2	2.2	2.3	11.6
AER draft decision	2.0	2.0	2.0	2.0	2.0	9.9
Difference	–0.7	–0.2	–0.2	–0.3	–0.4	–1.8

Source: Evoenergy, *SCS opex model,* 31 January 2023; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

122 Evoenergy, *SCS opex model,* January 2023.

123 Evoenergy, *Operating expenditure,* January 2023, p. 28.

In its proposal, Evoenergy submitted that a trend to a decentralised system, with an increasing uptake in CER technologies, has required it to develop capabilities to manage increasing levels of CER to connect and participate in the network.[124] Evoenergy considers these enabling capabilities to consist of the following categories:

1. network visibility
2. network operation
3. enabling projects.

In developing its CER strategy, Evoenergy completed a cost-benefit analysis and assessed 3 options to uplift these capabilities in a prudent and efficient manner. Evoenergy selected Option 2 (DER Readiness) as its preferred option and considered this to reflect a 'no regrets' approach to integrating and enabling CER.[125] This option is intended to enable foundation Distribution System Operator (DSO) capabilities, such as management of bi-directional power flows, and improved customer access to flexible exports.[126] Evoenergy also highlighted a trend in higher capacity rooftop solar systems being installed on its network. It submitted that the proposed investment would uplift capabilities that will result in better network utilisation and constraints management, including alleviating costly reactive remediation activities (e.g. over-voltage issues).[127]

We assessed the information provided in Evoenergy's proposal, including through an onsite workshop and subsequent information requests, to justify its costs of $11.6 million ($2023–24). We have also considered advice from our technical consultant, Energy Market Consulting associates (EMCa), in relation to this step change.

We consider it is prudent for Evoenergy to uplift its capabilities, to efficiently manage the energy transition towards an increasingly decentralised system with a growing volume of CER. We are satisfied that the network visibility and the network operation cost categories proposed in Evoenergy's preferred option 2 represent prudent and efficient investments. This is supported by EMCa's review, which considered that these components of Evoenergy's proposed investment option are justified, and that it is a proportionate enabling initiative.[128]

However, EMCa also raised concerns regarding whether Evoenergy's base opex included some step change costs, and whether its avoided opex assumptions in its cost-benefit analysis may be overestimated.[129] With respect to the base opex issue, we requested further clarifying information from Evoenergy, and are satisfied that the response adequately

124 Evoenergy, *Appendix 2.5: Distributed energy resources integration step change – Regulatory proposal for the ACT electricity distribution network 2024–29*, January 2023. p. 6.

125 Evoenergy, *Appendix 2.5: Distributed energy resources integration step change – Regulatory proposal for the ACT electricity distribution network 2024–29*, pp. 6–7.

126 Evoenergy, *Appendix 2.5: Distributed energy resources integration step change – Regulatory proposal for the ACT electricity distribution network 2024–29*, p. 23.

127 Evoenergy, *Appendix 2.5: Distributed energy resources integration step change – Regulatory proposal for the ACT electricity distribution network 2024–29*, pp. 12–13.

128 EMCa, *Evoenergy 2024 to 2029 Regulatory Proposal – Review of Proposed Expenditure on DER and Augex*, August 2023, pp. 18 and 22.

129 EMCa, *Evoenergy 2024 to 2029 Regulatory Proposal – Review of Proposed Expenditure on DER and Augex*, August 2023, pp. 15, 22–23.

addressed these concerns.[130] Regarding Evoenergy's avoided opex assumptions, we agree with EMCa and consider Evoenergy overestimated the likely benefits associated with this. However, our analysis showed that any adjustments to correct this methodology would not alter our decision.

In terms of the enabling projects category of costs, we are not satisfied that Evoenergy demonstrated that these costs are prudent. Specifically, Evoenergy's cost-benefit analysis model showed that Evoenergy's costs for this category exceed the identified benefits. This is further exacerbated, namely a further reduction in benefits, when we correct Evoenergy's benefits calculations to use more reasonable and appropriate assumptions. This is supported by EMCa, which also noted the negative NPV for this category. EMCa also advised that this category is not interdependent with the broader CER program, and therefore may be excluded without negatively impacting the total CER program. Namely, that after the removal of the enabling projects category, the remaining expenditure remains justified.[131]

For our alternative estimate of total forecast opex, we included $9.9 million ($2023–24) for the CER integration step change. This reflects our satisfaction that this amount reasonably reflects a prudent and efficient expenditure forecast for this step change.

6.4.4 Category specific forecasts

Evoenergy'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.

6.4.4.1 Debt raising costs

We have included debt raising costs of $2.9 million ($2023–24) in our alternative estimate. This is $0.3 million ($2023–24) lower than the estimate provided by Evoenergy.

Table 6.15: Debt raising costs ($million, 2023–24)

	2024–25	2025-26	2026–27	2027–28	2028–29	Total
Evoenergy's proposal	0.6	0.6	0.6	0.6	0.7	3.2
AER draft decision	0.6	0.6	0.6	0.6	0.6	2.9
Difference	–0.0	–0.0	–0.1	–0.1	–0.1	–0.3

Source: Evoenergy, *SCS opex model,* 31 January 2023; AER analysis.
Note: Number may not add due to rounding; Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

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 draft decision.

130 Evoenergy, *Information request IR#021 – DER step change – Confidential,* 22 May 2023.

131 EMCa, *Evoenergy 2024 to 2029 Regulatory Proposal – Review of Proposed Expenditure on DER and Augex*, August 2023, p 22.

Glossary

Term	Definition
AER	Australian Energy Regulator
AUC	Annual user costs
Capex	Capital expenditure
CCP26	Consumer Challenge Panel 26
CER	Consumer energy resources
CPI	Consumer price index
DMIA	Demand management innovation allowance
DNSP	Distribution network service provider
DSO	Distribution system operator
EBSS	Efficiency benefit sharing scheme
EMCa	Energy Market Consulting associates
LFiT	Large Feed-in Tariff
LSECD	Cobb-Douglas least squares econometrics
LSETLG	Translog least squares econometrics
MD	Maximum demand
MPFP	Multilateral partial factor productivity
MTFP	Multilateral total factor productivity
NER	National Electricity Rules
OEF	Operating environment factor
Opex	Operating expenditure
PPIs	Partial performance indicators
RIN	Regulatory information notice
RMD	Ratcheted maximum demand
RBA	Reserve Bank of Australia
SCS	Standard control services
SFACD	Cobb-Douglas stochastic frontier analysis
SFATLG	Translog stochastic frontier analysis
WPI	Wage price index