evoenergy

Attachment 3: Operating expenditure

Revised regulatory proposal for the Evoenergy electricity distribution determination 2024 to 2029

November 2023

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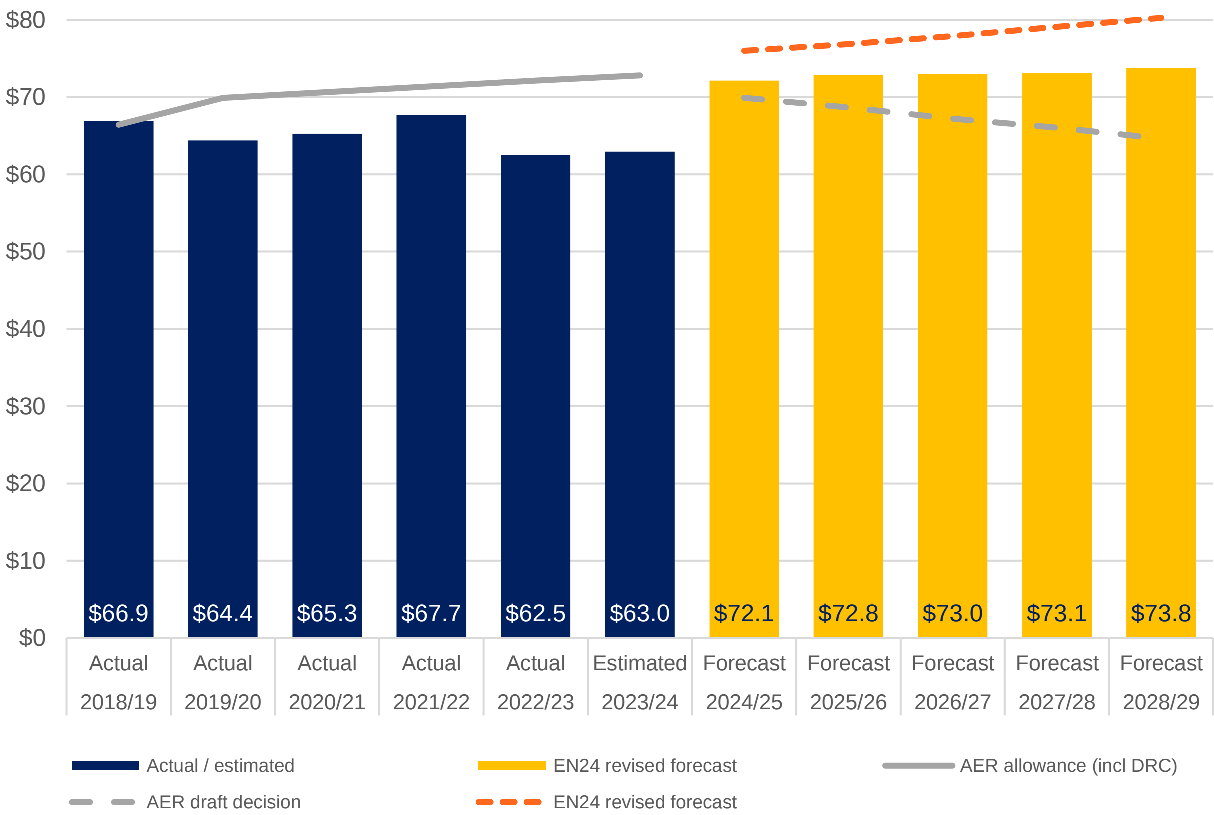
1. Overview

Evoenergy's Electricity Distribution Network Determination 2024–29 (EN24) Revised Regulatory Proposal includes an operating expenditure (opex) forecast of $364.8 million for the 2024–29 regulatory period. Our revised opex forecast is $28.3 million or 8.4 per cent higher than the Australian Energy Regulator's (AER) draft decision and $25.3 million or 6.5 per cent lower than our initial proposal, as shown in Figure 1 and Table 1.

We consider that our revised opex forecast reflects prudent and efficient costs of meeting and managing increasing expected demand, complying with our current and upcoming regulatory obligations, while also maintaining a reliable supply of electricity network services.[1] Our revised opex forecast reflects the efficient and prudent level of expenditure required by Evoenergy to maintain the quality, reliability and security of supply while operating safely and meeting service standard expectations. More than 10.6 per cent of the revised opex forecast is for opex step changes, including acceptance of the AER's draft decision for insurance premiums and Consumer Energy Resource (CER) integration.

Figure 1 Actual, estimated, and forecast opex ($ millions, 2023/24)



Note: Total forecasts and regulatory allowance include debt raising costs. Forecasts are not directly comparable due to updated inflation forecasts.

1 NER 6.5.6(a)

Table 1 Total opex forecast revisions ($ millions, 2023/24)

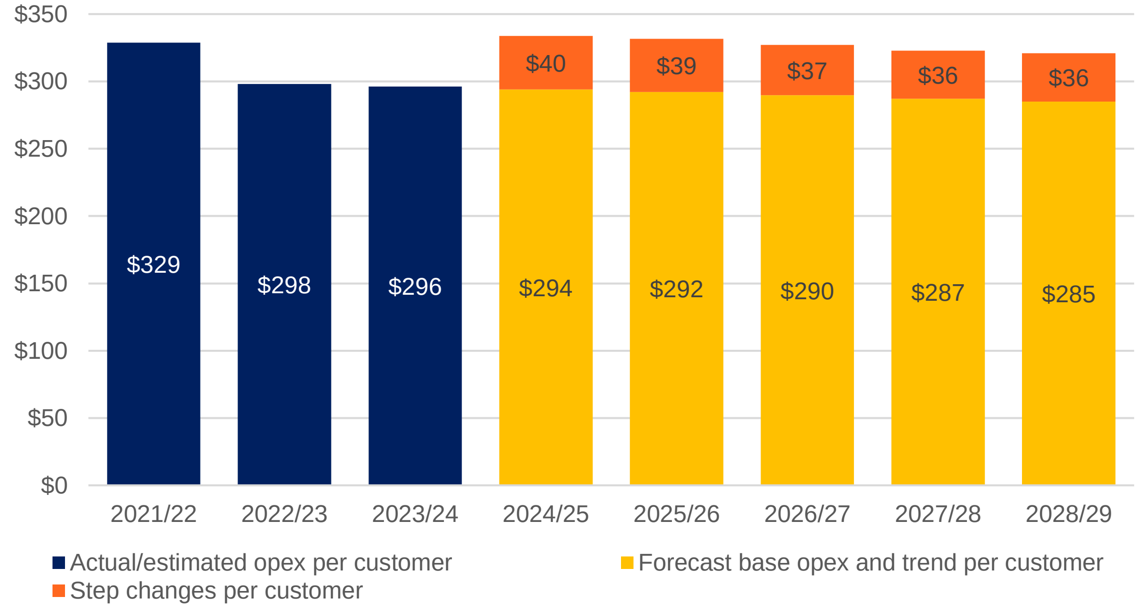
	EN24 regulatory proposal	AER draft decision	EN24 revised proposal
Opex forecast	$390.1	$336.5	$364.8
Change from initial EN24 regulatory proposal (%)		-13.7%	-6.5%
Change from initial EN24 regulatory proposal ($)		-$53.6	-$25.3

Note: Total forecasts include debt raising costs. Values are not directly comparable as they include different inflation estimates.

Our opex forecast and revised proposal accounts for the views of our consumers. Our consumers have indicated that they would like us to maintain existing service levels, including the reliability of supply. Our community indicated that they want us to invest in facilitating the ACT Government's electrification pathway, including the transition to a more decentralised energy system supporting greater uptake of new technologies such as electric vehicles, community batteries, and smart meters. Community groups have also noted that faster response times and the rapid restoration of power are critical to confidence in the electricity network's capacity to support all-electric homes in the energy transition as ACT customers move off gas.

We expect that our opex per customer over the 2024–29 period will remain relatively flat, decreasing over the forthcoming regulatory period, as shown in Figure 2. Our opex forecast considers the impacts on customers despite significant cost pressures with high inflation and expanding regulatory obligations.

Figure 2 Opex per customer ($2023/24)



Source: Evoenergy analysis.

2. AER draft decision summary

The AER's draft decision included an alternative opex forecast of $336.5 million, which reduced Evoenergy's opex forecast by $53.6 million or 13.7 per cent from our initial regulatory proposal. The AER's draft decision provided for the following inclusions and adjustments:

- Substitution of the 2021/22 base year with an alternative estimate as the AER considered that revealed opex was materially inefficient. Based on the AER's benchmarking analysis, a 15.7 per cent efficiency adjustment was applied, along with an allowance for a linear efficiency transition to pragmatically recognise how transformation programs involve time and implementation costs. This translated to a 9.4 per cent average annual efficiency adjustment.[2]
- Incorporated updated costings used to derive the backyard reticulation operating environment factor (OEF) for benchmarking analysis to capture historical planning practices in the ACT where overhead distribution lines run along backyard corridors rather than the street frontage (as is the practice for most distribution network service providers (DNSPs)).
- Application of a workers' compensation OEF to recognise that the ACT pays the highest rates in National Electricity Market (NEM) jurisdictions.
- A reduced trend component of the opex forecast, driven by a reduction in maximum demand forecasts.
- Adopted a placeholder value for the Security of Critical Infrastructure (SOCI) step change of $14.6 million, considering that it likely reflects prudent costs to comply with a new regulatory obligation within an evolving threat landscape.
- Partial acceptance of the proposed CER integration step change, reducing the allowance to exclude expenditure for community batteries.
- Acceptance of an insurance step change to account for increasing premiums resulting from more climate events, cyber-attacks, and general macroeconomic conditions.
- The AER included an alternative estimate of debt raising costs (DRC) of $2.9 million using their standard forecasting approach.
- The AER did not apply the Efficiency Benefit Sharing Scheme (EBSS) in their draft decision.[3]

The AER's draft decision requested additional information from Evoenergy on taxes and levies, and sought more information on our division of responsibility relating to vegetation management. Our revised regulatory proposal provides more information, including updated taxes and levies OEF. We propose to exclude a vegetation management OEF due to a lack of sufficient industry data.

Our response to the AER's draft decision on the adjustments to our initial proposal is provided in this document and supporting appendices.

2 AER, Draft Decision Evoenergy Regulatory proposal 2024 to 2029 Attachment 6 Operating expenditure, September 2023, pp. 3, 11, 24, 40-41

3 AER, Draft Decision Evoenergy Electricity Distribution Determination 2024 to 2029 Attachment 8 Efficiency benefit sharing scheme, September 2023

3. Our revised regulatory proposal

Our revised opex forecast is $364.8 million. The forecast is $25.3 million or 6.5 per cent lower than the initial regulatory proposal and a $28.3 million or 8.4 per cent increase from the AER's draft decision. Our revised regulatory proposal reflects the views of our customers. Specifically, our revised proposal has incorporated some of the AER's draft decision and includes some updated components to capture more recently available information:

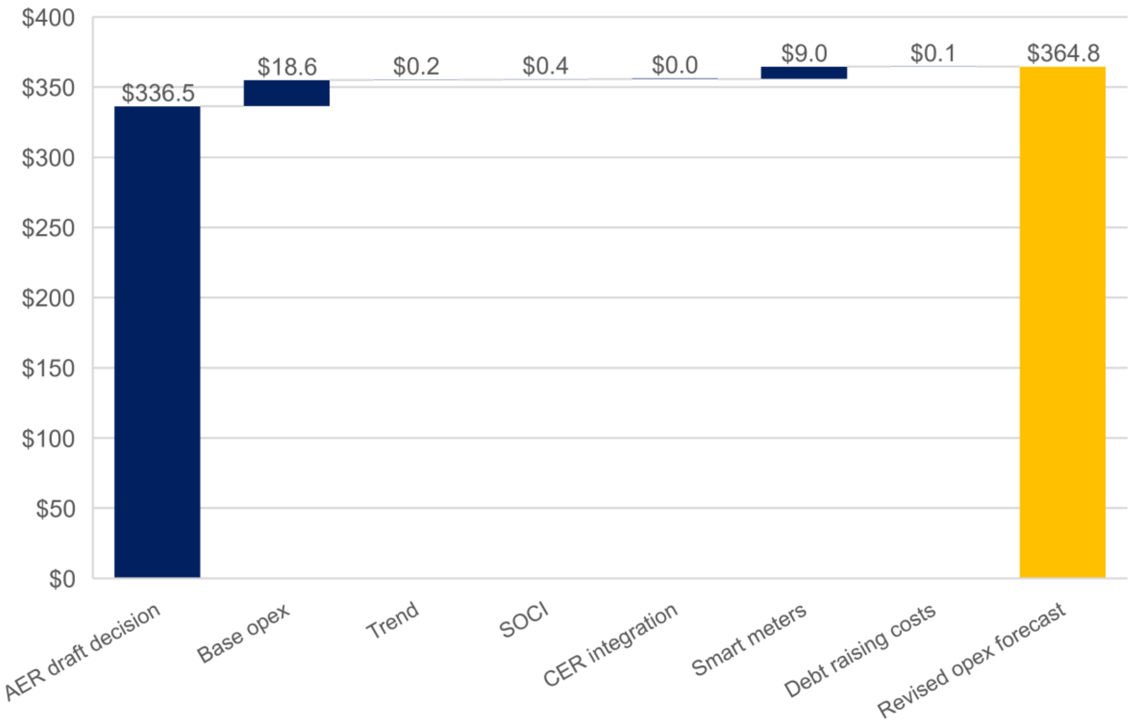
- updated opex base year, reflecting our audited efficient costs in 2022/23;
- no efficiency adjustment as our 2022/23 opex base year is efficient when our operating environment has been factored into the benchmarking analysis, including our distinct approach to expensing network overheads;
- with an efficient opex base year, updated the corresponding final year adjustments and trended opex applying the AER's preferred final year increment formula;
- accepts the AER's draft decision for insurance premiums;
- updated SOCI step change, supported with an evidence-based options analysis of efficient and prudent costs required to comply with new regulatory obligations;
- a new smart metering step change to capture Evoenergy's responsibilities under the Australian Energy Market Commission's (AEMC) finalised review of the regulatory framework for metering services and the recent rule change request for accelerating the deployment of smart meters and unlocking their benefits;
- accepts the AER's draft decision for CER integration step change, which excludes expenditure on community batteries;
- updates to inputs to capture more recently available data, including labour costs, maximum demand, circuit length, DRC to reflect our revised capital expenditure program, and inflation based on the Reserve Bank of Australia's August 2023 Statement of Monetary Policy; and
- incorporated an EBSS carryover as a revenue adjustment, reflecting that our 2022/23 revealed base year is efficient.

Our customers have told us they want us to maintain service standards and invest to allow for two-way energy flows and electrification. In a deep dive session, our Community Panel concluded that infrastructure investment is required to support new technology such as electric vehicles (EVs), community batteries, smart meters and electrification.[4] While our revised opex forecast will allow us to maintain service levels, we will only be investing enough to allow us to begin preparing for CER integration. We have adopted the AER's draft decision for CER integration, which excludes expenditure on community batteries. However, we will continue to monitor the economic viability of investing in community batteries, especially with government support. Our revised regulatory proposal includes expenditure for enabling the universal uptake of smart meters to allow data driven decisions and improve network safety.

The revised opex forecast from the AER's draft decision is shown in Figure 3. The main driver of the difference between the forecasts is the updated base opex, which includes a revised base year, no efficiency adjustment, and therefore excludes an efficiency transition allowance, adopts the AER's standard approach to calculating the final year increment, and captures updated inflation estimates. Opex efficiency is discussed in the next section.

4 Evoenergy Deep Dive Panel, Appendix C1 Deep Dive Panel Report, November 2023

Figure 3 Revised opex forecast from AER draft decision ($ millions, 2023/24)



Source: AER Draft decision – Evoenergy distribution determination 2024–29 – Opex model, September 2023; Evoenergy analysis.

Table 2 Revised opex forecast by component compared to AER draft decision ($ millions, 2023/24)

Opex component	EN24 proposal	AER draft decision	EN24 Revised proposal	Difference from AER draft decision
Adjusted base opex	$341.4	$275.3	$314.8	14%
Trend	$14.3	$7.9	$8.2	3%
Step changes	$31.2	$29.4	$38.8	32%
Insurance	$5.0	$5.0	$5.0	0%
SOCI	$14.6	$14.6	$15.0	3%
CER integration	$11.6	$9.9	$9.9	0%
Smart metering	-	-	$9.0	
Efficiency transition	-	$20.9	-	-100%
DRC	$3.2	$2.9	$3.1	4%
Opex forecast	$390.1	$336.5	$364.8	8.4%

Source: Evoenergy, Attachment 2 Operating Expenditure, January 2023, p. 31; AER – Draft decision – Evoenergy distribution determination 2024–29 – Opex model, Evoenergy analysis.

3.1. Base year efficiency

Evoenergy's revised opex base year opex is efficient

Accounting for additional information and evidence, Evoenergy updated the AER's efficiency benchmarking analysis, including the base year used to trend the revised opex forecast. We consider that our updated base year opex used for the revised forecast is efficient, and this section outlines the key variables that close the efficiency gap between the AER's draft decision and our revised proposal.

In the draft decision, the AER deterministically applied an efficiency adjustment based on its benchmarking models, concluding 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".[5] The AER "consider it [Evoenergy] 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".[6]

Evoenergy notes that the AER's benchmarking analysis is not undertaken on a like-for-like basis[7] as it does not account for all material differences in operating environments between DNSPs, or allow for evidence-based statistical uncertainty, and is based on econometric benchmarking models that suffer from serious misspecification problems. Consequently, the resulting efficiency estimates are likely to be biased and unreliable for the purposes of assessing the efficiency of base year opex. While we understand model misspecification is a critical and very complex issue with limited time to address biased efficiency outcomes within this reset process, our revised proposal includes a pragmatic approach using more recently available information to address how Evoenergy's opex is benchmarked in the context of our distinct operating environment.

Different operating environments give rise to DNSP cost advantages or disadvantages not accounted for in the AER's econometric cost function models. As such, the AER applies post-modelling adjustments using quantified operating environment factor (OEF) adjustments to account for material expenditure differences driven by exogenous factors beyond DNSP control that are not already captured in benchmarking analysis. Evoenergy operates in an environment different to other DNSPs and, as such, has assessed opex efficiency using the AER's preferred benchmarking approach, including an OEF adjustment for sub-transmission assets, termite exposure, backyard reticulation, workers compensation, taxes and levies, and network overheads. The details explaining OEF adjustments different to those included in the regulatory proposal and the AER's draft decision are detailed in the following sections and Appendix 3.1.

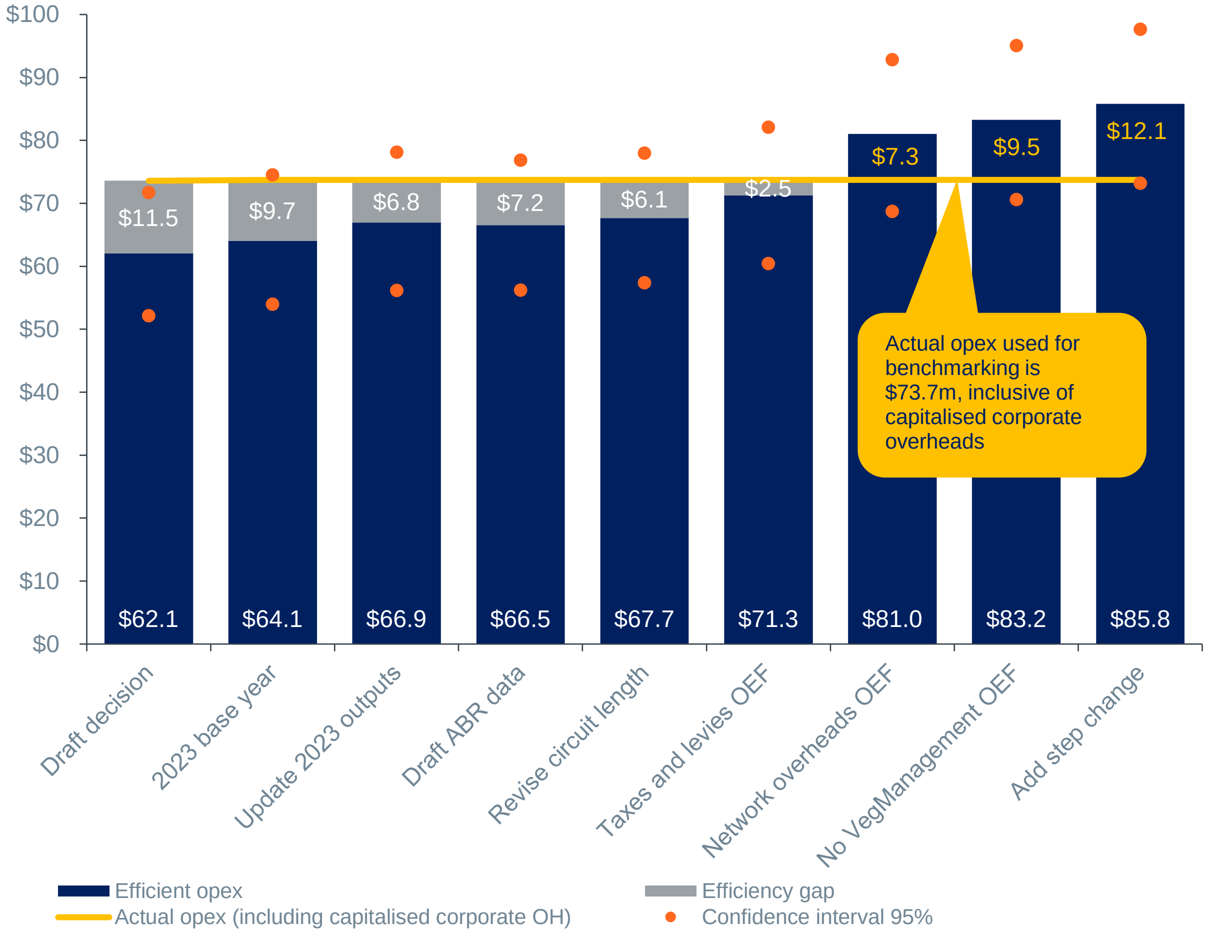
Considering our unique operating environment, Evoenergy's base year opex is efficient. Figure 4 summarises a quantified cumulative analysis of base year opex efficiency from the AER's draft decision to our revised regulatory proposal. The analysis has been updated using data underpinning the Draft AER 2023 Annual Benchmarking Report for several developments and additional information, as well as the most recent audited data from Evoenergy's 2022/23 Regulatory Information Notice (RIN).

5 AER, Decision Evoenergy Regulatory proposal 2024 to 2029 Attachment 6 Operating expenditure, September 2023, p. 14

6 AER, Decision Evoenergy Regulatory proposal 2024 to 2029 Attachment 6 Operating expenditure, September 2023, p. 13

7 This includes where opex is measured against individual metrics in partial performance indicator analysis and against other networks

Figure 4 Cumulative impacts of efficiency analysis on Evoenergy's opex efficiency from AER draft decision ($ millions, 2022/23)



Source: Frontier Economics, Appendix 3.1 AER Benchmarking of DNSP opex, November 2023.
Note: Circuit length values have been corrected, and may result in slight variations to the quantities provided in Figure 4.

The main factors contributing to an efficient opex base year, derived using the AER's assessment methodology, include:

- The revised proposal is based on the 2022/23 audited revealed opex, which is $9.7 million or 13.4 per cent below the AER's allowance for efficient opex.[8] Our 2022/23 opex reflects a $5.2 million or 7.7 per cent real reduction in opex compared with the 2021/22 opex base year included in our initial regulatory proposal.

  The AER's draft decision notes that "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".[9] The updated base year opex reflects the most recent available audited data on our efficient operating costs to ensure a safe and reliable electricity network that meets our consumers' expectations to maintain service standards. Opex in 2022/23 is reflective of expenditure that Evoenergy expects to incur on a recurrent basis.

8 Based on 2023/24 dollars, with estimated inflation based on the Reserve Bank of Australia's August 2023 Statement of Monetary Policy

9 AER, Decision Evoenergy Regulatory proposal 2024 to 2029 Attachment 6 Operating expenditure, September 2023, p. 12

As shown in Figure 4, the 2022/23 base year reflects an efficient base level of opex, which reduces the assumed efficiency gap by $1.9 million ($2022/23)[10] based on the econometric benchmarking models used in the AER's draft decision.

- Using the AER's opex roll forward approach, the opex efficiency gap narrows by $2.9 million ($2022/23) when updating Evoenergy's benchmarking outputs for 2022/23, including customer numbers and maximum demand.[11] Our 2022/23 actual outputs reflect continued growth in our customers' electricity demands as we observe the early stages of the energy transition in the ACT.
- Updating efficiency analysis based on the Draft AER 2023 Annual Benchmarking Report available at the time of writing, including data for all networks to 2021/22, increases the efficiency gap by $0.4 million ($2022/23).
- Evoenergy has corrected circuit length data for 2020/21 and 2021/22 based on the AER's RIN definition, ensuring that values are reported consistently with reinstated audited circuit length for 2005/06 to 2019/20. Corrected circuit length data and additional information on the 2022/23 underground share reported in the RIN decreases the efficiency gap by a further $1.1 million ($2022/23).
- Inclusion of a taxes and levies OEF based on an investigation prompted by the AER to provide additional information. The investigation found that Evoenergy had not provided data on the amount paid to the government for the entire averaging period used to quantify an OEF as part of the Sapre Merz review, narrowing the efficiency gap by $3.6 million ($2022/23). The impact of this OEF adjustment is predominantly driven by payroll taxes. The taxes and levies OEF adjustment for Evoenergy is not duplicative and is discussed in further detail below.
- Inclusion of an OEF adjustment that reflects differences in the practices between DNSPs in terms of capitalising network overheads. There are material variations between DNSPs in terms of the proportion of network overheads that are expensed vs capitalised. Historically, Evoenergy has fully expensed rather than capitalised network overheads. Failing to account for this difference between DNSPs places Evoenergy at a significant disadvantage in the benchmarking analysis and distorts estimates of period average efficiency.
- Removing an inappropriate vegetation management OEF which was calculated using incomplete industry information that is unsupported by evidence.
- Adding a vegetation management step change into the opex roll forward model to account for an uplift in regulatory obligations that are not captured adequately in the AER's approach to assessing efficient opex.

The impact of the updated data and additional information reveals that Evoenergy's base year opex is efficient. The estimate of efficient rolled forward opex based on the AER's methodology is $12.1 million or 16.4 per cent higher than Evoenergy's 2022/23 actual opex, including adjusting for capitalised corporate overheads. Evoenergy considers that it is also important to transparently and quantitively capturing statistical uncertainty, represented through confidence intervals. Therefore, Evoenergy considers its base year opex and revised forecast are both efficient and sufficient to ensure that we can achieve the operating expenditure objectives, factors, and criteria specified in the National Electricity Rules (the Rules).

We are concerned the AER's draft decision to apply a significant efficiency adjustment to opex would result in a forecast that would not be sufficient for Evoenergy to meet the operating expenditure objectives, factors, and criteria set out in the Rules. The AER's draft decision to apply an average efficiency adjustment of 9.4 per cent[12] may compromise Evoenergy's ability to maintain service standards, meet its customer demand for electricity, and impedes the delivery of the ACT

10 The reduction in the efficient gap is based on a reduction from $11.5m to $9.7m, derived using the AER's benchmarking models and opex roll-forward approach (calculated in 2022/23 dollars)

11 The updated 2023 outputs segment of the stepped efficiency analysis includes updating for customer numbers and maximum demand reported in the 2022/23 EBRIN, excluding 2022/23 circuit length reported in the EBRIN as this output is modelled separately

12 AER, Draft Decision Evoenergy Regulatory proposal 2024 to 2029 Attachment 6 Operating expenditure, September 2023, p. 3

Government's policy to achieve net zero emissions by 2045 through the uptake of EVs and substitution of household energy sources from gas to electricity.

As we consider our revised opex base year efficient, the forecast is derived using the base-step-trend approach, with no base year efficiency adjustment, updated for more recently available data and information. Accordingly, as discussed in section 5, we have applied the EBSS carryover and propose that it continues to apply in the 2024–29 regulatory period.

A taxes and levies operating environment factor adjustment should be applied

The AER's draft decision excluded a taxes and levies OEF adjustment (which the AER applies to other DNSPs when benchmarking their opex) and requested additional information in relation to the status of the payment and recovery of jurisdictional taxes and levies and whether it would be appropriate to account for these costs in the OEF framework.[13] Accordingly, Evoenergy has investigated this issue.

The AER's draft decision notes that Sapere-Merz recommended that a jurisdictional taxes and levies OEF not be applied in Evoenergy's case because doing so may breach the non-duplication criterion. The duplication criterion is that "the OEF should not have been accounted for elsewhere. Where the effect of an OEF is accounted for elsewhere, to provide an adjustment for that factor would be to double count the effect of the OEF".[14]

Sapere-Merz considered that the taxes and levies OEF should not apply to Evoenergy as it recovers jurisdictional taxes and levies through the B factor in annual pricing determinations.[15] The B Factor is defined as "the sum of annual adjustment factors for year t and includes the true-up for any under or over recovery of actual revenue collected through DUoS charges".[16] The B Factor adjustment is not a means for Evoenergy to recover jurisdictional taxes and levies. Evoenergy recovers jurisdictional taxes and levies through a jurisdictional scheme Unders and Overs account, which is independent of the B Factor. At the time of writing, taxes and levies that are trued-up through the Unders and Overs account include the Utilities Network Facilities Tax, Energy Industry Levy, and feed-in tariff schemes, including the Small-and-Medium Feed in Tariff and the Large Feed in Tariff. Jurisdictional Scheme costs are recovered through Evoenergy's Jurisdictional Scheme charges and not through distribution network charges.

Table 3 summarises the jurisdictional taxes and levies that Sapere-Merz advised the AER may be relevant to account for via an OEF adjustment to improve comparability of opex between DNSPs. Payroll and land taxes are both identified by Sapere-Merz to recognise variations in taxes and levies between DNSPs and jurisdictions.[17] However, in Evoenergy's case, there are two jurisdictional taxes that are not recovered by the jurisdictional scheme Unders and Overs account: payroll tax and land tax. Evoenergy recovers these jurisdictional taxes through standard control services (SCS) opex, and, therefore, is included with the SCS opex that is benchmarked by the AER. The payroll and land taxes incurred by Evoenergy are not accounted for anywhere within the AER's benchmarking analysis. Hence, failure to account for these jurisdictional taxes when benchmarking Evoenergy's opex will produce a distorted estimate of the efficiency of Evoenergy's historical opex.

13 AER, Draft Decision Evoenergy Regulatory proposal 2024 to 2029 Attachment 6 Operating expenditure, September 2023, p. 26

14 Sapere Merz, SapereMerz review of operating environment factors, August 2018, p. 28

15 Sapere Merz, SapereMerz review of operating environment factors, August 2018, p. 70

16 AER, AER - Final decision - Evoenergy distribution determination 2019-24 - Attachment 13 - Control mechanisms, March 2021, pp. 8, 12

17 Sapere Merz, SapereMerz review of operating environment factors, August 2018, p. 69

Table 3 Sapere-Merz potential taxes and levies

Industry specific	Federal	State
Distribution Licence Fee	Fringe benefits tax	Land and Property tax
Electrical Safety Levy	Other Government Charges and Levies	Distribution Lessor Corporation Land Tax
National Electricity Market Charge		Payroll tax
Energy Ombudsman Levy		Council Rates
Climate Change Fund		Water Rates
PV Feed In Tariff/Solar Bonus Scheme Rebate		Fire Services Levy
Heading		Other Government charges and levies

Source: Sapere Merz, Review of operating environment factors, August 2018, p. 69.

Notably, Evoenergy pays a significant amount of payroll tax to the ACT Government, which constituted a material proportion of opex in the 2022/23 base year. The ACT pays the highest payroll tax rates across NEM jurisdictions, as shown in Table 4.

Table 4 Payroll tax rates in different jurisdictions, 2022/23

Jurisdiction	Payroll tax rate (upper level)
ACT	6.85%
NSW	5.45%
NT	5.50%
Qld	4.95%
SA	4.95%
TAS	6.10%
VIC	4.85%
WA	5.50%

Source: Payroll Tax Australia, Rates and thresholds, September 2023.

Adjusting Evoenergy's target efficiency score for jurisdictional taxes and levies meets the OEF criteria of exogeneity, materiality, and non-duplication. The taxes and levies are outside management's control as these are imposed by the ACT Government, creating a material difference in Evoenergy's opex compared to other networks. Moreover, as noted above, the materially higher payroll tax and land tax incurred by Evoenergy are not accounted for elsewhere in the AER's benchmarking analysis. Taxes and levies that are trued up through the Unders and Overs account have not been included in our updated taxes and levies OEF, which ensures that the non-duplication criterion is satisfied. We have incorporated a taxes and levies OEF adjustment to the assessment of opex efficiency, adopting the AER's preferred approach.

An OEF adjustment can control for Evoenergy's unique approach to expensing network overheads

Given the timing of the AER's review into assessing the impact of capitalisation differences on benchmarking, Evoenergy's initial regulatory proposal did not explicitly propose any adjustment for its distinctive approach to expensing network overheads. However, we noted that we would monitor the outcome of the AER's final guidance note on how the AER will assess the impact of capitalisation differences on benchmarking analysis throughout the reset process as it may materially impact how base year efficiency is assessed.

The AER recognises that differences exist in how DNSPs expense and capitalise network overheads, and that the source of differences is not directly addressed under their preferred option to capture differences in corporate overhead accounting practices.[18] The AER's final position to not account for differences in the capitalisation of network overheads was based on its view of the nature of network overheads and the regulatory safeguards limiting strategic cost reallocations. We consider that the AER should apply a network overhead OEF adjustment in its assessment of Evoenergy's opex efficiency because:

1. *Evoenergy can report some operating activities as either corporate or network overheads*

   The AER notes that network overheads "vary significantly as a result of operating model choices and are also tied to the capex program".[19] Based on accounting standards and the AER's RIN definitions, expenditure can be categorised and reported as a corporate or network overhead. For example, given Evoenergy's corporate structure, we report procurement services as a corporate overhead in the Economic Benchmarking Regulatory Information Notice (EBRIN).[20] However, based on the AER's RIN definition, procurement can be reported as a network overhead.[21] Therefore, material cases of descriptive cost categories appear under network and corporate overhead cost categories based on accounting standards.

2. *Evoenergy's network overheads can be expensed or capitalised*

   Following Australian Accounting Standards in the context of capital expenditure, paragraph 16 of AASB 116, indicates that any costs, including overhead costs, directly attributable to bringing the asset to its location and condition necessary for it to be capable of operating as intended can be capitalised. Network overhead costs are inherently direct overhead costs that have a direct nexus with capitalisation and are thus in line with the recognition criteria of the

18 AER, How the AER will assess the impact of capitalisation differences on our benchmarking Final Guidance note, May 2023, p. 8

19 AER, How the AER will assess the impact of capitalisation differences on our benchmarking Final Guidance note, May 2023, p. 36

20 The AER's definition of corporate overhead "costs refer to the provision of corporate support and management services by the corporate office that cannot be directly identified with specific operational activity." (AER, Email from the AER: AER NOTIFICATION: Evoenergy - 2024-29 Regulatory period - RESET RIN ISSUED 27 October 2022 [SEC=OFFICIAL] [ACCC-ACCCANDAER.FID3031693], 27 October 2022)

21 The AER's definition of network overhead costs refers "to the provision of network, control and management services that cannot be directly identified with specific operational activity … may include the following … project governance and related functions including supervision, procurement, works management, logistics and stores …" (AER, Email from the AER: AER NOTIFICATION: Evoenergy - 2024-29 Regulatory period - RESET RIN ISSUED 27 October 2022 [SEC=OFFICIAL] [ACCC-ACCCANDAER.FID3031693], 27 October 2022)

Australian Accounting Standards. While Australian Accounting Standards allow for capitalisation, Evoenergy has historically expensed all network overheads.

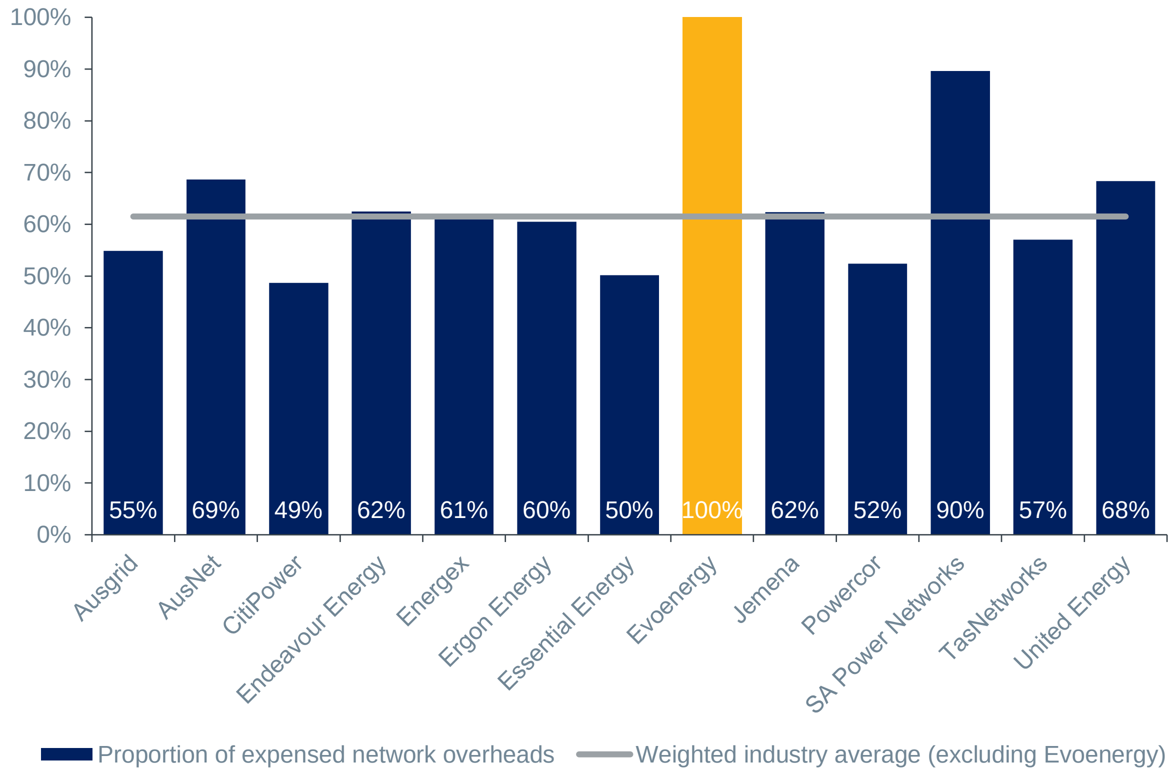
Examples of network overheads, which Evoenergy has historically expensed but which could be capitalised, include:

- System control room activities relating to outage coordination, planning, and switching directly attributable to capital projects.
- Advanced Distribution Management System (ADMS) activities that support (capital-related upgrades and system enhancements) system improvement, allowing for centralised management of the network, including outage management and performance optimisation.
- Network service engineers contribution to strategic and network planning activities that are directly attributable to asset creation and capitalisation.

3. *Evoenergy's historical practices of expensing network overheads are idiosyncratic, representing outlier characteristics relative to other networks it is being compared against*

As shown in Figure 5, Evoenergy has historically expensed all network overheads. The average proportion of expensed network overheads from 2009 to 2022 is 100 per cent for Evoenergy, the customer weighted industry average is 62 per cent (excluding Evoenergy) and 67 per cent for five reference DNSPs, showing that Evoenergy's historical practices are an outlier relative to other Australian networks that it is benchmarked against.

Figure 5 Average proportion of expensed network overheads, 2009 to 2022



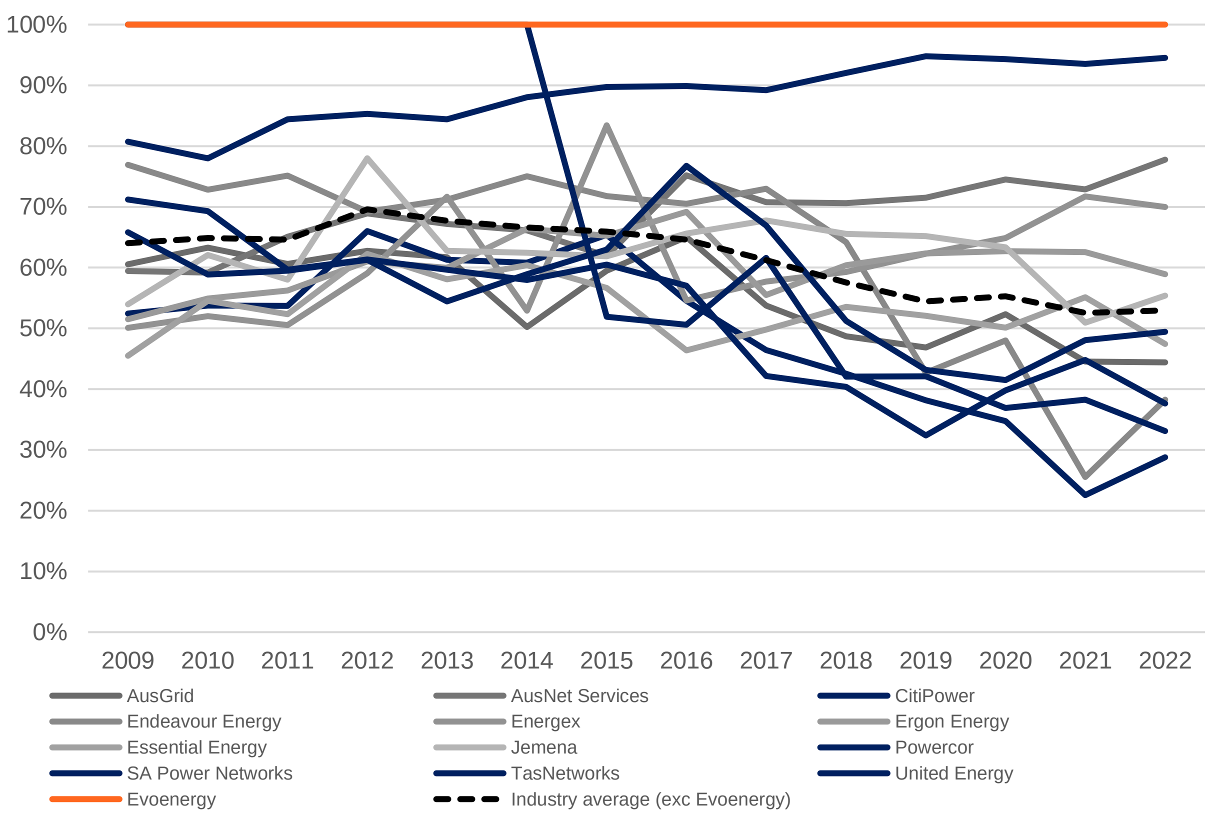
Source: Evoenergy analysis.

Additionally, annual network overhead capitalisation practices have changed over time. Figure 6 highlights an underlying trend of an increasing and diverging network overhead capitalisation rate across the networks. While the trend of the industry average declines over the 2009 to

2022 period, there is a growing divergence from 2015, when the AER began benchmarking opex.

Evoenergy's approach to expensing network overheads systematically and materially differs from every other network in the benchmark set. Given Evoenergy's unique approach to expensing network overheads relative to the DNSPs it is benchmarked against, we are materially disadvantaged in the AER's benchmarking analysis. The AER has recently stated that the aim of efficiency benchmarking is that results should largely reflect differences in DNSPs efficiency, with all other major sources of differences otherwise accounted for.[22] Therefore, it is necessary for the AER's assessment of Evoenergy's opex efficiency to address this material difference in the capitalisation of network overheads based on our historical idiosyncratic reporting practices.

Figure 6 Expensed network overheads as a proportion of total network overheads



Source: Evoenergy analysis of Category Analysis Regulatory Information Notice (CARIN) data. Note that the AER's reference DNSPs are reflected as a blue line in Figure 6.

4. *Regulatory safeguards do not ensure like-for-like comparisons in opex benchmarking*

The AER's decision on treating differences in capitalisation practices considers that opex benchmarking does not need to be adjusted for network overheads as the regulatory framework has "safeguards to protect against strategic cost re-allocations (between corporate and network overheads) by DNSPs."[23] These 'regulatory safeguards' are not defined. Still, Evoenergy understands they could include accounting standards, the AER's RIN definitions, the AER's approved Cost Allocation Methodology (which varies between DNSPs), and the

22 AER, How the AER will assess the impact of capitalisation differences on our benchmarking, , May 2023, p. iii

23 AER, How the AER will assess the impact of capitalisation differences on our benchmarking, May 2023, p. v

AER's ability to monitor strategic cost re-allocations.[24] However, none of these regulatory mechanisms have adequately ensured like-for-like accounting treatment for network overheads across networks.

Given that Evoenergy has historically expensed rather than capitalised network overheads, not adjusting for network overheads undermines the comparability of Evoenergy's opex used in the AER's benchmarking analysis. Evoenergy should not be penalised due to different historical reporting approaches. As such, Evoenergy's assessment of opex efficiency using the AER's benchmarking model includes an OEF adjustment to account for network overheads to capture the unique outlier characteristics of capitalisation practices. Appendix 3.1 details the development and calculations of an OEF adjustment, and Frontier Economics' analysis demonstrates that expensing network overheads materially impacts Evoenergy's comparative efficiency.

A vegetation management OEF derived using inadequate industry information is not appropriate

The vegetation management OEF includes two components: a Victorian bushfire risk obligations OEF and a division of responsibility OEF. The AER's draft decision applied the two vegetation management OEFs to assess Evoenergy's opex efficiency, with OEF adjustment of -2.94 per cent for bushfire risk and zero per cent for division of responsibility.[25]

Vegetation management – bushfire risk OEF

The bushfire risks OEF intends to capture differences in opex due to additional regulatory obligations associated with bushfire risk mitigation responsibilities (generally related to vegetation management) imposed on Victorian DNSPs in 2011. Evoenergy considers that the Victorian bushfire risk mitigation OEF should not apply in assessing opex efficiency in the 2024–29 regulatory determination for the following reasons:

1. *All networks have obligations to mitigate bushfire risk*

   The bushfire risk OEF is more accurately described as 'Victorian bushfire regulations' and is specific to Victorian DNSPs but has been applied as a negative adjustment to Evoenergy operating in the ACT. The AER assumes (without providing any supporting evidence) that Victorian networks have consistently faced a material cost disadvantage due to more stringent bushfire risk mitigation regulatory obligations than other networks.

   The *Utilities (Technical Regulation) (Electricity Powerline Vegetation Management Code) Approval 2018*, section 4.2.1(1), explains that Evoenergy's "Works Plan must include alternative long-term measures for reducing the risk of ignitions and bushfires caused by vegetation near aerial lines that are more environmentally sustainable than trimming in excess of minimum clearance distances, including technical modifications".[26] All DNSPs have bushfire risk mitigation responsibilities. However, we have been unable to quantify vegetation management-related bushfire risk mitigation expenditure as costs overlap with vegetation management clearance cycles, asset inspection activities, and general climatic conditions.

2. *There are many conflating variables, making it difficult to reasonably proxy quantified impacts of bushfire risk mitigation expenditure*

   The bushfire risk OEF is calculated using forecast costs (approved by the AER as a step change) associated with bushfire obligations (rather than actual costs) as the AER considers that it is unlikely actual costs will reflect the incremental change in additional obligations due to the fluctuating impacts of changes in weather conditions and vegetation management cycles.[27] We agree that there is considerable uncertainty around the quantification of vegetation management costs directly associated with bushfire risk mitigation, and consider this is conflated by variables challenging to itemise, such as climate conditions and vegetation

24 For example, see AER, How the AER will assess the impact of capitalisation differences on our benchmarking, May 2023, p. 16

25 AER, Draft Decision Evoenergy Regulatory proposal 2024 to 2029 Attachment 6 Operating expenditure, September 2023, p. 26

26 Utilities (Technical Regulation) (Electricity Powerline Vegetation Management Code) Approval 2018 | Disallowable instruments

27 AER, Draft Decision Evoenergy Regulatory proposal 2024 to 2029 Attachment 6 Operating expenditure, September 2023, p. 30

management cycles. For this reason, adopting forecast estimated costs is not an appropriate mechanism in which to impose a fixed percentage post-modelling adjustment to benchmarking outcomes as there are many variables affecting the relationship between vegetation management expenditure associated with bushfire regulations.

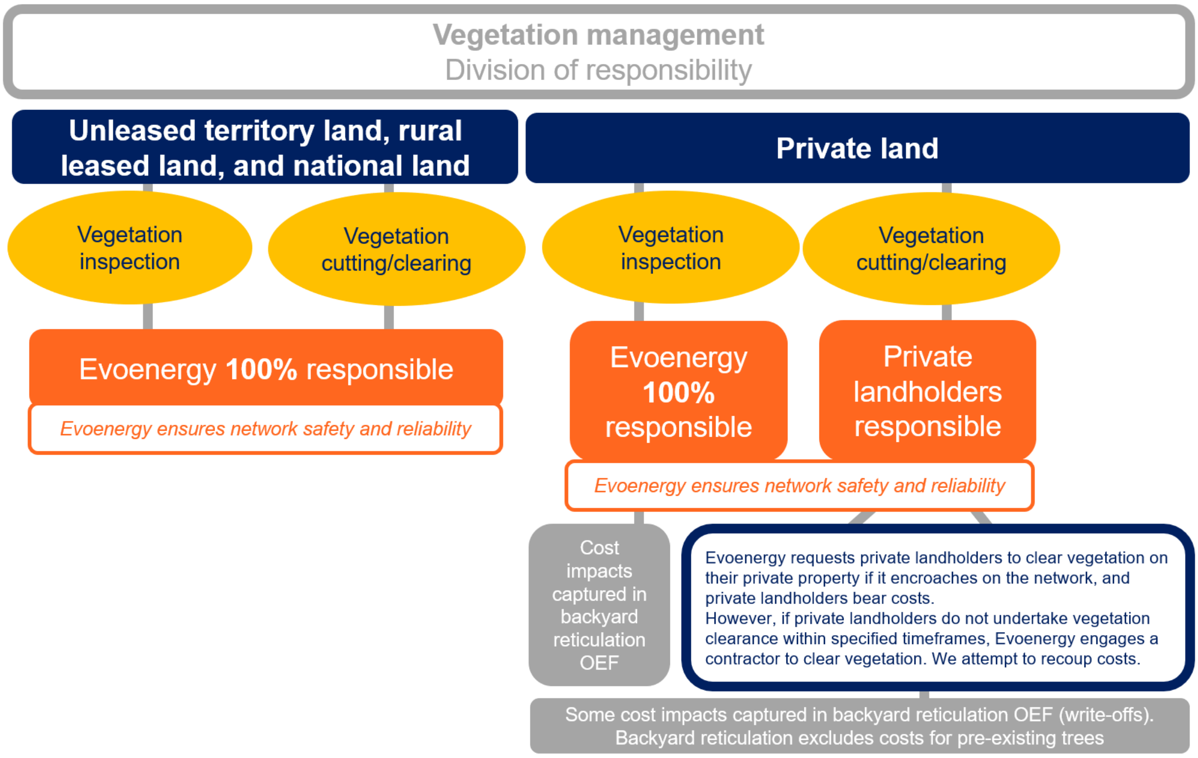
3. *An OEF adjustment should be based on verified evidence and analysis*

   The AER considers that the Victorian DNSPs have more stringent bushfire risk mitigation responsibilities relative to other jurisdictions. Insufficient analysis has been undertaken to define the specific differences in legislation and regulations to substantiate the claim that Victorian DNSPs face more obligations that materially impact opex. An OEF adjustment should not be based on the mere assumption that regulatory obligations may materially impact opex but instead should be based on verifiable evidence.

Vegetation management – division of responsibility OEF

The division of responsibility OEF seeks to quantify the operating cost advantage some DNSPs gain due to third parties bearing responsibility for a portion of vegetation management under differing jurisdictional regulatory obligations. The AER's draft decision was to apply a zero per cent division of responsibility OEF for Evoenergy.[28] The draft decision sought further information on the division of responsibility and ACT-specific vegetation management regulatory obligations.[29] Additional information on vegetation management is presented in Figure 7 and explained further in Table 5.

Figure 7 Vegetation management division of responsibility and backyard reticulation in benchmarking



28 AER, Draft Decision Evoenergy Regulatory proposal 2024 to 2029 Attachment 6 Operating expenditure, September 2023, p. 30

29 AER, Draft Decision Evoenergy Regulatory proposal 2024 to 2029 Attachment 6 Operating expenditure, September 2023, p. 31

Table 5 Vegetation management division of responsibility information

Vegetation management in the ACT

Evoenergy is responsible for delivering a safe and reliable electricity supply, which includes ensuring that vegetation does not encroach on the electricity network in the ACT. In the context of vegetation management, it is important to consider the distinction between inspecting vs clearing and removing vegetation that is encroaching on the electricity network.

As shown in Figure 7, Evoenergy is responsible for:

- 100 per cent of vegetation inspections on private and public land; and
- 100 per cent of vegetation clearing and removal, except for clearing vegetation on private land.

In the draft decision, the AER noted that under backyard reticulated planning practices, "land holders have had primary responsibility for managing vegetation for approximately 15% of Evoenergy's route line length. This is similar to the 18% of vegetation management undertaken by councils in the comparator DNSP states of Victoria and South Australia"[30]. While the AER referenced page 86 of its 2014–19 draft decision to obtain the 15 per cent, Evoenergy has not been able to validate this figure.

Vegetation inspections

Evoenergy is responsible for inspecting all vegetation that encroaches on its electricity network. Evoenergy undertakes vegetation inspections on its assets, including the low and high voltage networks, to ensure safety and to mitigate bushfire risks. A portion of Evoenergy's low voltage network is in private landholders' backyards, known as backyard reticulation.

The AER's draft decision accepted Evoenergy's updated backyard reticulation OEF, which accounts for additional opex associated with inspecting network vegetation encroachment in backyards,[31] finding that we incurred $0.67 million in 2021/22 for direct costs related to backyard vegetation inspections. Evoenergy undertakes backyard vegetation inspections to ensure the network remains safe. The backyard reticulation OEF includes adjusting benchmarking analysis to account for the operating costs of inspecting vegetation encroachment on private land.

However, Evoenergy must also inspect vegetation encroachment on the remainder of the electricity network (that is for unleased territory land, rural leased land, and national land) to ensure the delivery of safe and reliable network services. Therefore, Evoenergy performs all network vegetation inspections and incurs the costs associated with that activity. However, the inspection of vegetation encroachment on public land is not accounted for in the backyard reticulation OEF or elsewhere else in the AER's benchmarking analysis.

Vegetation clearing and removal activities

Evoenergy undertakes 100 per cent of vegetation clearing and removal responsibilities (including 208 pre-existing trees on private land) to ensure the delivery of safe and reliable network services, except for vegetation encroachments on private land in backyards. Under the NER, Evoenergy is responsible for maintaining network safety and reliability.

Evoenergy is responsible for clearing and removing vegetation that is encroaching on the network on unleased territory land, rural leased land, and national land. Evoenergy's responsibilities were assumed from the ACT Government's Transport Canberra and City Services based on amendments to the *Utilities (Technical Regulation) Act 2014 (ACT)* that came into effect on 1 July 2018. Under the legislation (section 41D), Evoenergy is responsible for the clearance of vegetation near an aerial line on unleased territory land, rural leased land, and national land. Evoenergy undertakes activities reasonably necessary for the clearance of vegetation near an aerial line, including the felling or looping of trees, trimming of roots of trees or other plants, and the clearing or removal of vegetation. The additional regulatory obligations associated with vegetation management had a significant impact on Evoenergy's incurred opex, with vegetation management expenditure increasing by 51 per cent from

30 AER, Draft Decision Evoenergy Regulatory proposal 2024 to 2029 Attachment 6 Operating expenditure, September 2023, p. 31

31 AER, Draft Decision Evoenergy Regulatory proposal 2024 to 2029 Attachment 6 Operating expenditure, September 2023, pp. 31-32

2017-18 to 2018-19.[32] Notably, the total and unit costs of vegetation inspection and clearance will vary between jurisdictions based on different regulatory requirements, geography, climate conditions, local labour markets, and general economic conditions.

Private landowners incur costs for vegetation clearance in their backyard when vegetation encroaches on the electricity network (except for pre-existing trees). Adequate vegetation clearance distances on overhead lines must be maintained to ensure a safe and reliable electricity system. As mentioned above, Evoenergy undertakes inspections to ensure that safe vegetation distances are maintained.

Under the *Utilities (Technical Regulation) Act 2014 (ACT)*, Evoenergy is responsible for issuing network protection notices, including requesting private landholders to trim vegetation encroaching on the electricity network.[33] The cost disadvantage of issuing protection notices is accounted for in the backyard reticulation OEF.

In response to Evoenergy's request to trim vegetation encroaching on the electricity network, some customers undertake trimming and clearing activities to ensure safe network operations, and some refuse. In the event of multiple customer requests and inaction within a specified timeframe, to maintain safe vegetation clearance distances on the network, Evoenergy contracts clearance and removal activities to ensure network safety and reliability, with the costs billed to the customer. Evoenergy only undertakes vegetation removal in backyards when there is a safety concern related to network interference. In such instances, vegetation management clearance costs are recovered from customers. However, there are instances where property owners refuse to pay and are sent to debt collectors.[34] Evoenergy incurs an annual write-off, which has increased over time, with 20 per cent of invoices written off in 2022/23. This cost is accounted for in the updated backyard reticulation OEF that the AER approved in the draft decision.

Source: Evoenergy.

It is not currently possible to adequately normalise differences in DNSP incurred expenditure related to the division of responsibility due to conflating variables (such as geographic and climatic conditions) that cannot be separated and differences in regulatory obligations between jurisdictions that are difficult to quantity. Evoenergy considers that the division of responsibility OEF should not apply in assessing opex efficiency in the forthcoming 2024–29 regulatory Determination for the following reasons:

1. *Industry information and consultation is needed to understand the cost impacts of differing levels for the division of responsibility*

   The AER acknowledges that the vegetation management OEF "does not directly quantify vegetation management cost differences" but considers it a reasonable proxy without sufficient quality data.[35] Evoenergy agrees that the lack of data does not allow for reliable and robust quantification of the OEF. The AER assumes that DNSPs in Victoria and South Australia do not undertake 18 per cent of vegetation management, based on information provided by AusNet Services in 2014.[36] A sample size of one dating back to 2014 is not a reliable basis for quantifying an OEF, and the AER should seek more relevant information and evidence to build its assumptions, accounting for how regulations change over time.

2. *The methodology for adjusting for differences of division of responsibility should not confound incompatible variables and should reflect realistic assumptions, which differ between networks*

   The methodology adopted by the AER to quantify the division of responsibility OEF conflates variables that are not comparable, based on assumptions specific to AusNet Services in 2014,

32 Based on Category Analysis Regulatory Information Notices

33 Under Division 5.2(32)(2), the responsible utility may give the landholder written notice to take whatever action is necessary to stop the interference with the regulated utility network or network facility, or to remove the likelihood of that interference

34 Utilities (Technical Regulation) Act 2014, Division 5.2, 32(5)(b)

35 AER, Draft Decision Evoenergy Regulatory proposal 2024 to 2029 Attachment 6 Operating expenditure, September 2023, p. 30

36 AER – Draft decision – Evoenergy distribution determination 2024-29 – Vegetation management OEF – September 2023.xlsx, September 2023

and which are uniformly applied to all DNSPs with no evidence that such an application is appropriate. The AER multiplies the estimated total share of vegetation management costs borne by councils (24 per cent) by the percentage of an electricity network that is the responsibility of councils (12 per cent) specific to the operating area of AusNet Services, resulting in the assumption that Victorian and South Australian DNSPs are not responsible for 18 per cent of costs. This approach does not account for responsibilities that other third parties, such as landholders, may bear. The methodology fails to recognise that different jurisdictions have alternative operating environments with variable climate and geographic conditions impacting the average unit cost of vegetation management – that is, unit rates for vegetation clearing and removal may vary considerably between jurisdictions.

3. *There are many variables that conflate cost impacts of vegetation clearing*

   There are many differences in vegetation clearing and removal between jurisdictions, including regulations for clearing distances, geographic location, planting density, and climate conditions. Vegetation clearance distances and frequency cycles are also key considerations when accounting for vegetation management operating cost advantages and disadvantages. Evoenergy has a biennial vegetation clearance cycle for urban areas (our network is predominantly urban), with a higher frequency level due to lower clearance distances. Evoenergy can only clear to sky in rural areas. It is difficult to quantify cost differences between jurisdictions and account for these conflating variables.

4. *Vegetation management responsibilities are evolving within the context of stronger environmental safeguards*

   Vegetation management responsibilities are expanding in the ACT as the government implements stronger environmental safeguards. Evoenergy will incur additional responsibilities from 1 January 2024 under the *Urban Forest Act 2023 (ACT)*, which replaces the *Tree Protection Act 2005 (ACT)*. The legislation seeks to improve tree protection on public and private land by broadening the definition of protected trees, introducing a Canopy Contribution Framework, and tree bonds. Except for emergencies, Evoenergy must gain permission from the ACT Government to undertake any work that may impact a protected tree on public and private land by submitting a Tree Activity Application. Evoenergy expects that the new regulation will result in an uplift in the extent of its obligations and commensurate costs as it may impact maintenance activities and project planning. Due to the timing of the legislation, Evoenergy has not been able to quantify the impacts of the additional regulatory obligations on the opex forecast for the forthcoming 2024–29 regulatory period.

5. *Under the Rules, all networks are responsible for maintaining a safe and reliable electricity supply*

   Vegetation management reduces the risk of encroachment on overhead assets to mitigate community exposure to electrocution, electric shock, power outages, and network damage. All networks have a level of responsibility for vegetation management and to ensure that safe and reliable network services are delivered. Evoenergy's regulatory obligations related to vegetation management practices are outlined in our 2022 Vegetation Management (Bushfire and Environmental Works Plan), published on our website.[37]

Evoenergy has significant vegetation management responsibilities in relation to the division of responsibility that should be accounted for in benchmarking analysis. We consider that differences should be captured in the opex roll forward approach, not through an OEF adjustment given the lack of comparable data across networks.

In the draft decision, the AER considered that Evoenergy's increased division of responsibility incurred from 2018 (approved as an efficient step change in the 2019–24 regulatory period) should be accounted for in the Victorian bushfire risk obligations OEF. If the AER does seek to capture the cost impacts on benchmarking of Evoenergy's additional vegetation management responsibilities as an OEF, it should be done in a manner that adequately allows for a prudent and efficient opex allowance, as required under the NER. An illustrative example of appropriately capturing the impacts of

37 Examples of legislative obligations include the Utilities (Technical Regulation) Act 2014; Utilities (Technical Regulation) Electricity Powerline Vegetation Management Code 2018; Utility Networks (Public Safety) Regulation 2001; Emergencies Act 2004; Nature Conservation Act 2014; and the Urban Forest Act 2023

increased vegetation management responsibilities is included in Appendix 3.1, which results in an equivalent efficient opex level between capturing impacts using the opex roll forward approach or an alternative OEF approach.

Overall, we have significant concerns about the AER's methodology, assumptions, lack of evidence and current industry data to support the application of the vegetation management OEFs to Evoenergy. Therefore, the revised regulatory proposal excludes vegetation management OEF adjustments to the assessment of opex efficiency. The benchmarking analysis includes the impacts of vegetation management incurred from 2018 in the AER's opex roll forward approach. If the AER does seek to account for additional costs using an OEF, it should adequately account for prudent and efficient expenditure.

Evoenergy welcomes further engagement with the AER on the complex nature of accounting for operating differences in vegetation management and how to capture cost impacts in its benchmarking analysis.

The opex roll forward model should account for material changes in vegetation management costs approved by the AER

Our regulatory proposal submitted that the opex roll forward model should account for material changes in regulatory obligations, such as those approved by the AER in its 2019 final decision as a vegetation management step change needed to comply with expanded regulatory obligation based on amendments to the *Utilities (Technical Regulation) Act 2014 (ACT).*

The AER's draft decision did not accept incorporating additional regulatory obligations for vegetation management in the opex roll-forward approach, stating that their preferred approach is to make an adjustment using the vegetation management OEF.[38]

Evoenergy considers that the AER's alternative estimate of base year opex does not reflect the prudent and efficient costs required to adequately deliver electricity network services as specified in the National Electricity Rules (NER). Specifically, the AER's approach fails to account for the change in regulatory obligations faced by Evoenergy over the period. The AER has not accounted for any additional increase in costs faced by Evoenergy between the middle of the sample period and the base year to comply with the new obligations. Consequently, the AER's approach of accounting for the step change in Evoenergy's vegetation management costs solely through an OEF adjustment does not account properly for the impact of those costs on Evoenergy's efficient base year opex.

Accounting for vegetation management as a step change allows for the cost impact to be recognised at a particular time, rather than adjusted for using an OEF, which is applied to the average rolled forward opex over the relevant benchmarking period.

Frontier Economics provides additional information on incorporating the vegetation management step change and suggested approaches to incorporating the impacts in the AER's benchmarking analysis in Appendix 3.1.

The AER's assessment of whether revealed base year opex is efficient should take into account the statistical uncertainty involved in such an assessment

The AER's benchmarking analysis and opex roll forward process derive a point estimate of what it considers efficient base year opex. Given that the estimated efficient opex is derived by *estimating* econometric cost functions, the point estimate inherently has a degree of statistical uncertainty. That is, the AER's estimate of efficient base year opex is not an observable number—it is a figure that is estimated with statistical uncertainty.

The AER should explicitly recognise uncertainty when assessing whether Evoenergy's revealed opex is materially inefficient. Specifically, the AER should allow for a range of uncertainty in econometric

38 AER, Draft Decision Evoenergy Regulatory proposal 2024 to 2029 Attachment 6 Operating expenditure, September 2023, p. 34

modelling to capture statistical error associated with its estimate of period average efficiency and the other parameters estimated from the opex cost functions that are used to roll forward the estimate of efficient opex to the base year.

Using confidence intervals around a point estimate improves the transparency of the range of statistical uncertainty of the point estimate of efficient opex.[39] If the revealed opex falls within statistically derived confidence intervals, then the AER cannot be confident that the revealed opex is materially inefficient.

The AER considers that it adopts a conservative approach to benchmarking by applying a 0.75 comparison point to account for model limitations and data imperfections.[40] However, uncertainty in statistical analysis should be quantified, basing the value on evidence to derive a probabilistic assessment of opex efficiency. Evoenergy encourages the AER to explore basing its conservative approach to benchmarking on evidence using confidence intervals to make informed probabilistic assessments of opex efficiency rather than regulatory judgment.

Evoenergy engaged Frontier Economics to analyse the range of the AER's efficiency scores using confidence intervals to recognise that the efficiency scores reflect an estimate within a range and are not an absolute measure that can or should be deterministically applied in regulatory Determinations. Further details on statistical uncertainty are provided in Appendix 3.1.

Serious statistical issues mean benchmarking results cannot be used deterministically

In productivity analysis, economic theory expects that an increase in outputs can only be achieved with an increase in inputs, holding all else constant. Monotonicity violations occur when this condition is not satisfied. The AER has recognised that monotonicity violations have become increasingly prevalent in relation to some of its benchmarking models. The AER's advisers have investigated possible approaches to reduce the instances of these monotonicity violations by making the 'translog' versions of the AER's benchmarking models less flexible. However, the AER was unable to find an approach that adequately addresses monotonicity violations.

Frontier Economics has advised that the monotonicity violations are likely due to a fundamental misspecification of the econometric models and that attempts to make the translog models less flexible simply targets the symptoms rather than the fundamental misspecification problem. Evidence supporting the misspecification of the models that the AER deterministically applied in the draft decision is detailed in Appendix 3.1.

Frontier Economics has advised that the source of the misspecification problem is likely to be the highly restrictive assumption that the DNSPs' efficiency remains constant over time. However, there is compelling evidence that suggests that Australian DNSPs have become more efficient over time (materially so, in some cases) since 2014. Improvement in DNSP efficiency has been acknowledged by the AER.[41]

Failing to account for improved efficiency will result in biased estimates of key parameters in the AER's econometric models (including the time trend term) and period average efficiency for individual DNSPs. Misspecification of the benchmarking models will result in biased efficiency estimates, rendering results unreliable to set regulatory allowances. As the opex econometric cost function models do not fit the data well, they cannot be deterministically relied upon to quantify an efficiency adjustment, which is the approach adopted by the AER in their draft decision.

It is important to note that this misspecification problem affects all AER's benchmarking models—not just the translog models that exhibit monotonicity violations. This is because all of the AER's benchmarking models assume constant efficiency over time. However, the consequences of the model misspecification are more apparent in the case of the translog models, which are highly flexible in their functional form. This results in them 'overfitting' the data and producing monotonicity

39 Frontier Economics, Appendix 3.1 AER Benchmarking of DNSP opex, November 2023, p. 23

40 AER, Draft Decision Evoenergy Regulatory proposal 2024 to 2029 Attachment 6 Operating expenditure, September 2023, pp. 12, 28, 38, 40

41 For example, AER, draft 2023 Annual Benchmarking Report for Electricity distribution network service providers, November 2023, p. v

violations. That is to say, the monotonicity violations that the AER has observed for years are likely to indicate a deeper problem afflicting all benchmarking models.

We recognise that a significant amount of work may be required by the AER and the wider industry to develop alternative models that are specified more appropriately to fit the salient features of the benchmarking data. This will take time and close collaboration between the AER and DNSPs. We recognise that it is not realistic to expect the AER to complete this work within the timeframes for this reset. However, given the seriousness of the statistical problems identified by Frontier Economics, and the implications for the AER's use of econometric models to undertake benchmarking analysis to assess the efficiency of revealed base year opex, Evoenergy submits that the AER should interpret the results of its benchmarking analysis with a high degree of caution. The results of the benchmarking analysis should not be used mechanistically in this reset, as this could result in the adoption of an opex forecast for the 2024–29 regulatory period that is insufficient to meet the opex objectives, factors, and criteria specified in the NER, which would not promote the long-term interests of consumers.

3.2. Base year adjustments and final year increment

Base year adjustments

The AER's draft decision accepted Evoenergy's base year adjustments, accounting for movements in provisions, the Demand Management Innovation Allowance (DMIA), and removal of the administration costs of the ACT Government's Large Feed in Tariff Scheme (LFIT) approved in the Reasonable Cost Determination.[42]

Evoenergy's revised regulatory proposal is based on the 2022/23 revealed opex and includes adjustments to reflect the updated base year. The base opex used to trend the revised forecast does not include DMIA expenditure or LFiT administration costs, but does include an adjustment for the movement in provisions, consistent with the AER's preferred approach.

The revised opex forecast does not include a base adjustment for LFiT administration costs due to the changed way in which incurred expenditure is reported in 2022/23 and will be recovered. LFiT administration costs are reported and included as a jurisdictional scheme payment, reflecting the approach taken in the ACT Government's 2022/23 Reasonable Cost Determination (RCD).

Our revised regulatory proposal does not include a base adjustment for DMIA expenditure as from 2022/23, Evoenergy changed the way in which DMIA costs are reported. DMIA costs are reported in the Annual RIN table 7.11.2 instead of EBRIN opex. Evoenergy has made this change to reflect the nature of the DMIA costs, which are recovered through an increment to the revenue allowance rather than the opex allowance.

Final year increment

The AER's draft decision amended the calculation of the final year increment based on its assessment that our 2021/22 opex was materially inefficient, which included rolling forward opex rather than applying their standard final year increment formula. For our revised opex forecast, we have adopted the AER's preferred final year increment calculation as per their Expenditure Forecast Assessment Guideline, based on our revealed 2022/23 opex, reflecting an efficient level of expenditure when our unique operating circumstances are accounted for in the AER's benchmarking analysis.

42 AER, Draft Decision Evoenergy Regulatory proposal 2024 to 2029 Attachment 6 Operating expenditure, September 2023, pp. 41-42

3.3. Step changes

Evoenergy's regulatory proposal included $31.2 million in opex step changes to account for additional regulatory obligations relating to the Security of Critical Infrastructure (SOCI) Act, increasing insurance premiums driven by global climate events, and a CER integration to facilitate the energy transition through increased visibility of the low voltage network.[43] Evoenergy's regulatory proposal also noted the potential for a smart meter step change pending the outcome of the AEMC metering review.[44]

The AER's draft decision accepted our opex step change for insurance premiums, accepted, as a placeholder, our proposed step change for SOCI, and accepted most of our proposed CER integration step change, with the exclusion of the expenditure to support community batteries.[45]

The revised opex forecast includes $33.8 million for opex step changes, representing 10.6 per cent of the total opex forecast. As shown in Table 6, our revised proposal:

- accepts the AER's draft decision on the insurance step change;
- adopts the AER's draft decision for CER integration, which was supported by our customers, but excludes expenditure for community batteries;
- provides further evidence to support the prudency and efficiency of SOCI expenditure, including our response to finalised regulatory compliance obligations, additional market testing, and more information as we progressed the assessment of activities required to mitigate risk within the context of an evolving security threat surface, resulting in a small uplift in expected costs; and
- includes a new step change for Evoenergy's responsibilities relating to facilitating the universal uptake of smart meters, based on outcomes of the AEMC's review of the regulatory framework for metering services[46] and the recent rule change request for accelerating the deployment of smart meters and unlocking their benefits.[47]

43 The initial regulatory proposal included a Distributed Energy Resources integration step change. While not all DER is CER and all CER is DER, we have used the terms interchangeably.

44 Evoenergy, Attachment 2 Operating expenditure, January 2023, p. 26

45 Australian Energy Regulator, Draft Decision Evoenergy Regulatory proposal 2024 to 2029 Attachment 6 Operating expenditure, September 2023, pp. 49-51

46 See Australian Energy Market Commission, Final report review of the regulatory framework for metering services, August 2023

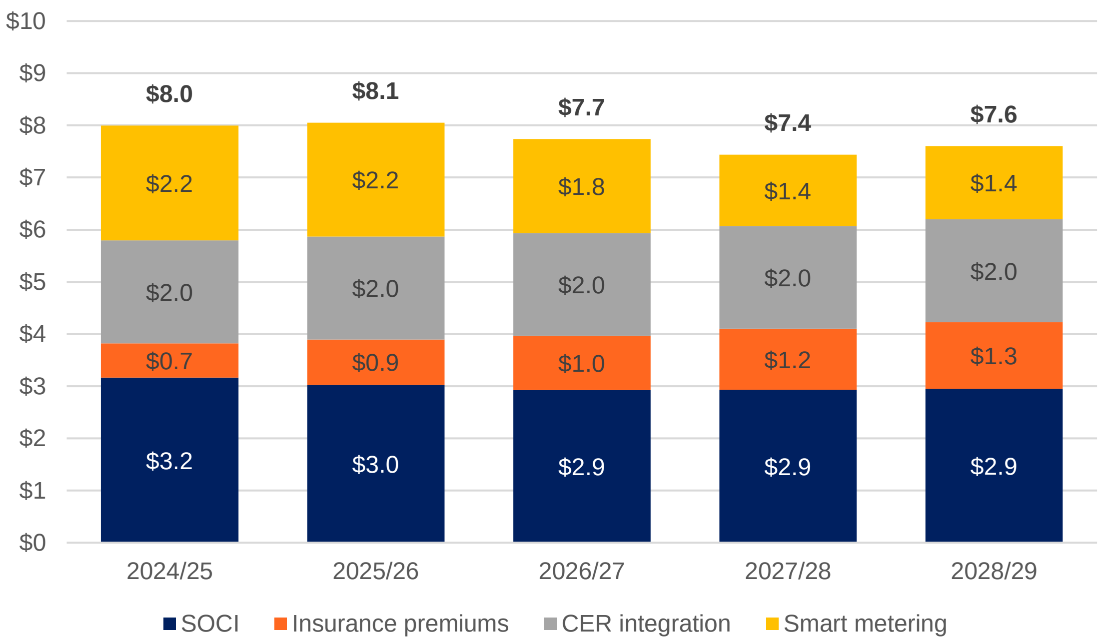
47 Intellibub, SA Power Networks, and Alinta Energy, Accelerating smart meter deployment – Rule Change Request, September 2023

Table 6 Opex step changes ($ millions, 2023/24)

Step changes	EN24 proposal	AER draft decision	EN24 revised proposal	Change from AER draft decision
Insurance premiums	$4.99	$5.02	$5.02	0%
SOCI	$14.56	$14.56	$14.99	3%
CER integration	$11.61	$9.85	$9.85	0%
Smart metering	-	-	$8.96	-
Total step changes	**$26.17**	**$24.41**	**$33.80**	**38%**

Note: Forecasts may not be directly comparable as inflation has been updated to reflect the most recently available information.

Figure 8 Revised opex step changes ($ millions, 2023/24)



Source: Evoenergy analysis. Note: numbers may not add due to rounding.

Consumer Energy Resources Integration step change

Evoenergy's proposal included a CER integration step change for our revised regulatory proposal, designed to:

- facilitate increased visibility of the low voltage network through procuring and analysing data such as smart meter data;
- mobilising the ACT distribution network to accommodate dynamic operating envelopes to minimise export curtailment and ensure more equitable export allocation through IT software; and
- investing in enabling projects such as community batteries and voltage management systems (capex) to address network capacity constraints.

Our community and the ACT Government have indicated support for CER investment to facilitate greater uptake and allow for two-directional energy flows as we electrify. While tour Community Panel supported investment in community batteries, the revised opex forecast does not include expenditure to support community batteries, consistent with the AER's draft decision. Evoenergy simultaneously recognises our community's interest and support for investing in community batteries and that the benefits modelled in the initial cost benefit analysis are not strong enough at this time.[48] However, we will continue to monitor the economic viability of community batteries as the energy transition towards net zero gains momentum, ensuring that our investments are prudent, efficient, and well-timed.

As noted in our revised regulatory proposal, we consider that the DMIA allowance is insufficient to enable Evoenergy to co-fund community battery projects in the ACT. While community battery investment is supported by federal and jurisdictional government co-funding programs to encourage electrification and promote innovation, the AER has not allowed adequate expenditure (either in the draft decision regulatory allowance or through the DMIA scheme) for Evoenergy to invest in community batteries the forthcoming regulatory period. Other electricity networks with larger revenue allowances receive substantially higher DMIA allowances, allowing for participation in community battery co-funding schemes. We heard from our community that they support community battery investment to support the energy transition. We are concerned that the current approach to calculating Evoenergy's DMIA level means that the ACT community has limited opportunity to realise the potential benefits.

Security of critical infrastructure

Evoenergy's initial regulatory proposal included proposed expenditure to comply with amendments to the *Security of Critical Infrastructure Act 2018* (SOCI Act) (Cth), which consumers broadly supported. The CCP26 suggested that Evoenergy did not provide an "explanation of what the $14.6 million would be spent on, and what outcomes it would achieve", concluding that the "CCP26 does not believe this step change was fully understood by Panel members".[49] Our initial proposal and revised regulatory proposal includes expenditure to manage the evolving personnel, cyber, supply chain, physical security and natural hazard risks associated with an evolving threat surface. Information presented to the Community Panel included an explanation of SOCI, including that the SOCI step change would deliver outcomes to protect the information of our customers and ensure that Evoenergy's ICT support services are delivered by suitably qualified and vetted personnel. Publicly disclosing specific itemised activities to comply with SOCI and facilitate an uplift in security undermines the deliverability of an increased security posture needed to comply with legislated obligations. While we have not publicly disclosed the specific activities that will be undertaken to comply with our regulatory obligations, we have worked closely with the AER and their consultants to ensure that the SOCI step change represents prudent and efficient costs.

48 The initial proposal CER integration cost benefit analysis did not capture the benefits of emissions reduction due to the timing of the updated National Energy Objectives.

49 Consumer Challenge Panel, CCP26 Advice to AER re Evoenergy 2024-29 Regulatory Proposal and AER Issues Paper, 12 May 2023, p. 15

The AER's draft decision accepted a placeholder value based on Evoenergy's proposed opex step change to meet new regulatory obligations under amendments to the SOCI Act.[50] While the AER's draft decision stated that the AER is satisfied an uplift in expenditure is likely to be prudent, they considered further assessment needs to be undertaken on the prudency and efficiency of the expenditure before making its final decision.

For our revised proposal, we have developed a business case,[51] which provides evidence supporting revisions to the revised opex forecast. The SOCI step change reflects prudent and efficient expenditure needed to meet additional regulatory obligations under the amended legislation. The business case sets out each of the relevant SOCI obligations, interventions required to meet the obligations, and an assessment of the relevant options regarding costs and risk.

Table 7 shows the step change forecast included in our initial proposal, the AER's draft decision, and our revised opex proposal. The revised opex forecast includes an uplift in SOCI expenditure of $0.4m or 3.0 per cent compared to the initial proposal, which captures additional information obtained from market providers to deliver on our additional regulatory obligations and manage risk. The revised SOCI step change will enable Evoenergy to continue providing reliable network services and maintain customer privacy within the context of an evolving cyber threat surface.

We welcome further engagement with the AER before making its final determination to ensure it can be satisfied that our revised proposal reflects the prudent and efficient costs to comply with new SOCI regulatory obligations while mitigating risks that could impact the security and reliability of electricity supply.

Table 7 SOCI opex step change ($ millions, 2023/24)

	2024/25	2025/26	2026/27	2027/28	2028/29	Total
EN24 regulatory proposal	$2.90	$2.90	$2.86	$3.02	$2.89	**$14.56**
AER draft decision	$2.90	$2.90	$2.86	$3.02	$2.89	**$14.56**
EN24 revised regulatory proposal	$3.16	$3.03	$2.93	$2.93	$2.95	**$14.99**

Note that numbers may not add due to rounding.

50 AER, Draft Decision Evoenergy Regulatory proposal 2024 to 2029 Attachment 6 Operating expenditure, September 2023, p. 49

51 Evoenergy, Appendix 3.3 SOCI business case, November 2023; Evoenergy, Appendix 3.3.1 SOCI cost model, November 2023

Smart meter step change

On 31 August 2023, the AEMC published recommendations on the review of the regulatory framework for metering services to target the universal uptake of smart meters through an accelerated deployment program. On 22 September 2022, a consortium of proponents put forward a rule change request for accelerating the deployment of smart meters and unlocking their benefits.[52] The outcomes of the AEMC metering review and proposed rule change requires Evoenergy, as the network provider, to:

- develop and enable the implementation of a legacy meter replacement program (LMRP) for the accelerated deployment of smart meters across the ACT;
- expand system and process capabilities to capture, process, and store significantly higher volumes of smart meter data for billing purposes; and
- implement new system capabilities and processes to capture, process, and store basic power quality data.

Evoenergy's revised regulatory proposal includes a new opex step change for the costs of fulfilling responsibilities outlined in the AEMC's final report, which have been reflected in a proposed fast-tracked rule change. The AEMC expect that facilitating the accelerated roll-out of smart meters will include many market benefits, including network planning and customer safety.

The incremental costs to deliver on the AEMC's final report relate to IT capability to capture, store, and process smart metering data and additional labour resources to develop and manage the smart meter roll out program in the ACT. Under the final report, Evoenergy's legacy meter replacement plan would be due to the AER from late 2024 to early 2025, with the date yet to be confirmed. Evoenergy has developed a smart meter step change that provides capability uplift to deliver on the smart meter roll-out, ensuring that costs are not double counted, are incremental to the base year, and is a project that is not already accounted for in the rate of change.

The smart metering step change includes some costs for the procurement of basic power quality data required to undertake neutral safety analysis until the data becomes free of charge for DNSPs. Neutral integrity failures can cause hazardous voltages to be present in accessible areas and can cause equipment failure. The detection of neutral integrity failure is a significant benefit identified as part of the AEMC's metering review. We have included costs for the procurement of basic power quality data and the software and necessary IT system integrations to improve network safety outcomes for our customers related to neutral safety. Importantly, all voltage data, load detection, and CER compliance (processing, analytics, and software) expenditure has been accounted for in the CER step change, ensuring that costs are not double counted.

Our proposed smart meter step change is shown in Table 8.

Table 8 Smart meter step change ($millions, 2023/24)

	2024/25	2025/26	2026/27	2027/28	2028/29	Total
Smart Metering step change forecast	$2.20	$2.19	$1.80	$1.37	$1.40	**$8.96**

Note: totals may not sum due to rounding.

52 Intellihub, SA Power Networks, Alinta energy, Rule change request: Accelerating the deployment of smart meters and unlocking their benefits, 22 September 2023

3.4. Trend

Our revised regulatory proposal updates the real price growth and output change forecasts to reflect more recently available data since our initial regulatory proposal. We accept the AER's draft decision to apply a 0.5 per cent productivity growth forecast. Table 9 provides a summary of our revised proposal trend forecast. The trend or rate of change is $6.3 million or 44.4 per cent below the initial regulatory proposal and $0.2 million or 2.9 per cent higher than the AER's draft decision.

Table 9 Revised opex forecast rate of change ($ millions, 2023/24)

	2024/25	2025/26	2026/27	2027/28	2028/29	Total
Input price change	$0.45	$0.95	$1.26	$1.57	$1.93	$6.16
Output growth	$0.46	$0.92	$1.38	$1.84	$2.31	$6.92
Productivity change	-$0.32	-$0.65	-$0.98	-$1.32	-$1.66	-$4.93
Total rate of change	**$0.59**	**$1.23**	**$1.67**	**$2.09**	**$2.58**	**$8.16**

Source: Evoenergy analysis. Note: totals may not sum due to rounding.

Price change

The AER's draft decision accepted our initial regulatory proposal with respect to non-labour price growth and the input price weighting between labour and non-labour. Our revised proposal accepts the AER decision on these elements.

The AER's draft decision did not accept our labour price growth forecasts, which were based on forecasts of the Wage Price Index for the utilities sector prepared by BIS Oxford Economics in November 2022. The draft decision instead took an average of our labour price growth forecasts and the AER's consultant's labour price growth forecasts prepared by KMPG in August 2023. The AER's draft decision also added the legislated Superannuation Guarantee increase, which is not reflected in the Wage Price Index forecasts.

For our revised proposal, we engaged Oxford Economics (formerly BIS Oxford Economics) to update its labour price growth forecasts, with details of the forecast included in Appendix D. Evoenergy's real labour cost escalators included in the revised opex forecast is based on the average of Oxford Economics updated forecasts from October 2023 and KPMG's forecasts from August 2023. We have accepted the AER's draft decision to apply the Superannuation Guarantee increase. Details of forecast price change are shown in Table 10.

Table 10 Forecast real price change

	2024/25	2025/26	2026/27	2027/28	2028/29
Real labour - Oxford Economics forecast	1.31%	1.10%	0.80%	0.66%	0.96%
Real labour - KPMG forecast	0.08%	0.61%	0.85%	0.93%	0.95%
Superannuation Guarantee	0.50%	0.50%	0.00%	0.00%	0.00%
Real labour escalation	1.19%	1.35%	0.82%	0.79%	0.95%
Labour weight	59.2%	59.2%	59.2%	59.2%	59.2%
Forecast real price change (annual)	**0.71%**	**0.80%**	**0.49%**	**0.47%**	**0.56%**

Source: AER Draft decision – Evoenergy distribution determination 2024–29 – Opex model, September 2023; Appendix D; Evoenergy analysis.

Output change

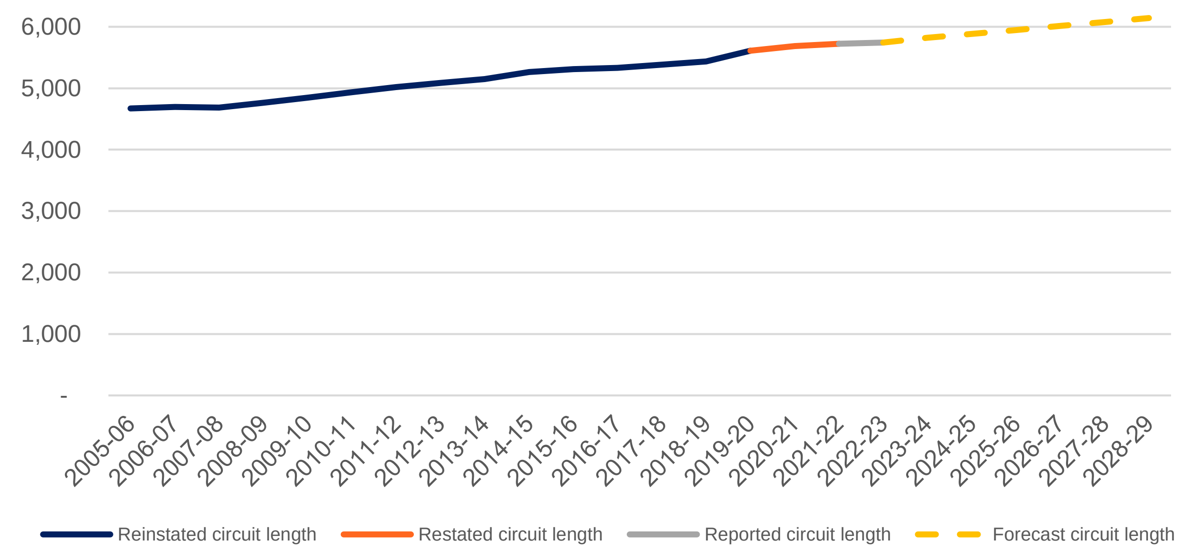
The AER's draft decision accepted our forecast customer number growth, updated circuit length, and maximum demand forecasts. Our revised opex forecast includes updated output growth forecasts to reflect the most recent available actual 2022/23 data, including for customer numbers, and to ensure consistency with our revised regulatory proposal capital expenditure forecast. We have also updated the output weights to reflect the AER's Draft 2023 Annual Benchmarking Report.

Circuit length

The AER's draft decision included a lower forecast growth rate of circuit length to reflect the forecast included in Evoenergy's Reset RIN.[53] The revised opex forecast includes an updated circuit length forecast to reflect our audited 2022/23 circuit length reported in the RIN and our revised proposal capital expenditure program.

In assessing our revised proposal circuit length forecasts, the AER should also note that Evoenergy identified an error in the previously reported circuit length data between 2019/2020 and 2021/22, which has been corrected through the RIN process. Evoenergy has also reinstated audited circuit length data reported through the RIN for 2005/06 to 2019/20 to align with the RIN definition and ensure that values are reported on a consistent basis. Figure 9 shows the accurate circuit length for 2005/06 to 2022/23, and Evoenergy's forecast circuit length for the revised opex forecast.

Figure 9 Historical and forecast circuit length (km) 2006 to 2029



Source: Economic Benchmarking Regulatory Information Notice; Evoenergy analysis.

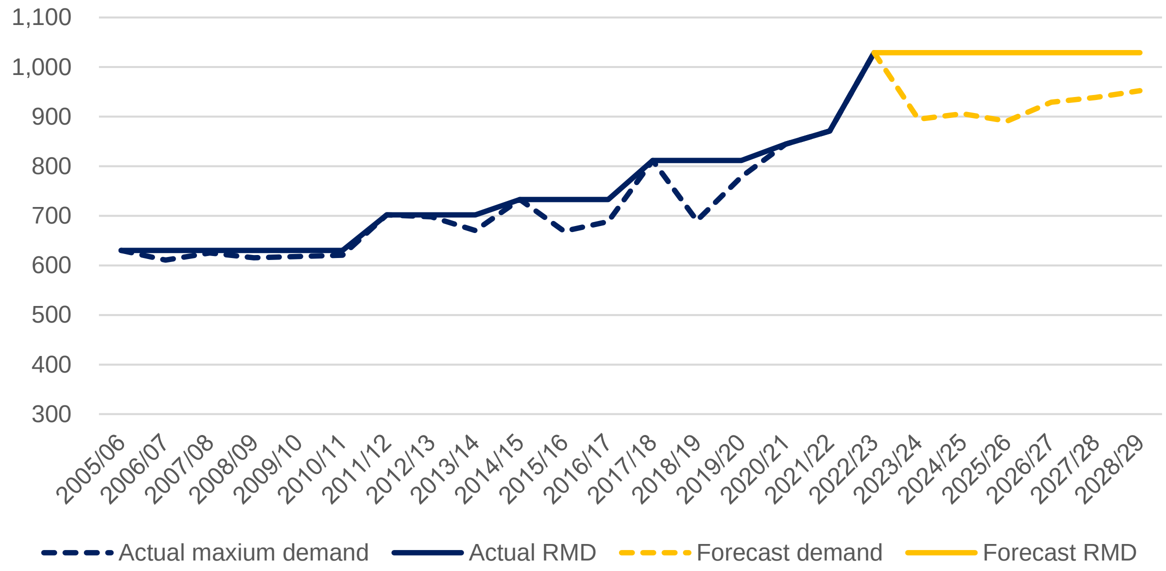
53 AER, Draft Decision Evoenergy Regulatory proposal 2024 to 2029 Attachment 6 Operating expenditure, September 2023, p. 45

Ratcheted maximum demand

The AER's draft decision included a lower growth rate for ratcheted maximum demand (RMD) than proposed by Evoenergy based on forecast maximum demand measured at the zone substation with a probability of exceedance of 50 per cent.[54] This is inconsistent with the AER's benchmarking approach, which adopts demand measured at the bulk supply point as an output variable to proxy network capacity.[55]

Our revised regulatory proposal includes an updated forecast of RMD, capturing more recently available data on actual demand and based on forecast demand measured at the bulk supply point. Notably, Evoenergy's non-coincident maximum demand measured at the bulk supply point increased by 18 per cent from 2021/22 to 2022/23, as shown in Figure 10. We have retained a forecast of no increase in RMD over the forthcoming regulatory proposal.[56]

Figure 10 Non-coincident summated raw system annual maximum demand measured at the bulk supply point (MW)



Source: Economic Benchmarking Regulatory Information Notice, Evoenergy analysis.

54 AER, Draft Decision Evoenergy Regulatory proposal 2024 to 2029 Attachment 6 Operating expenditure, September 2023, pp. 45-46

55 AER, Annual Benchmarking Report Electricity distribution network service providers, November 2022, p. 74 ; Economic Insights, Economic Benchmarking of Electricity Network Service Providers, 25 June 2013

56 Note that ratcheted maximum demand is a measure of non-coincident system maximum demand measured at the transmission point, reflecting the dual function nature of Evoenergy's network. Our zone-substation and feeder augmentation requirements are based on load forecasts prepared at these lower levels. For more detail on these growing forecasts see Attachment 2.

Output weights

Evoenergy's revised regulatory proposal has adopted output weights derived from the AER's Draft 2023 Annual Benchmarking Report (ABR), available when finalising the opex forecast. Output elasticities used for the revised opex forecast are shown in Table 11. The AER may update the trend to reflect the output weights in the final 2023 Annual Benchmarking Report.

Table 11 Opex benchmarking output elasticities

Opex output measures	Cobb-Douglas Stochastic Frontier Analysis	Cobb-Douglas Least Squares Econometrics	Translog Least Squares Econometrics	Translog Stochastic Frontier Analysis
Customer numbers	0.364	0.565	0.401	0.369
Circuit Length	0.132	0.170	0.182	0.092
Ratcheted Maximum Demand	0.475	0.238	0.373	0.445

Source: AER Draft 2023 Annual Benchmarking Report.

While the AER's standard elasticities have been applied in the opex model, the output weights represent a relationship between opex and outputs of international DNSPs and are not Australian-specific. Evoenergy considers that outputs applied in forecasting opex should be specific to Australia and not skewed by overseas businesses, such as Ontario DNSPs, operating in very different environments. Additionally, Evoenergy notes that the AER's econometric cost function model presents statistical issues and may be mis-specified. Evoenergy expects that the AER will undertake further analysis and engage with other DNSPs as part of its benchmarking development work.

3.5. Debt raising costs

Evoenergy's revised opex forecast includes debt raising costs (DRC). Evoenergy accepts the AER's draft decision to update benchmarking costs using the notional debt issue size and determining the value in accordance with the methodology set out in the report by Allen Consulting Group, Debt and equity raising transaction costs: final report to the ACCC, December 2004. Evoenergy notes the value will be updated again by the AER in its final decision. The DRC included in the revised opex forecast is presented in Table 12.

Table 12 Debt raising costs ($ millions, 2023/24)

	2024/25	2025/26	2026/27	2027/28	2028/29	Total
Debt raising costs	$0.6	$0.6	$0.6	$0.6	$0.6	**$3.1**

Note: numbers may not add due to rounding.

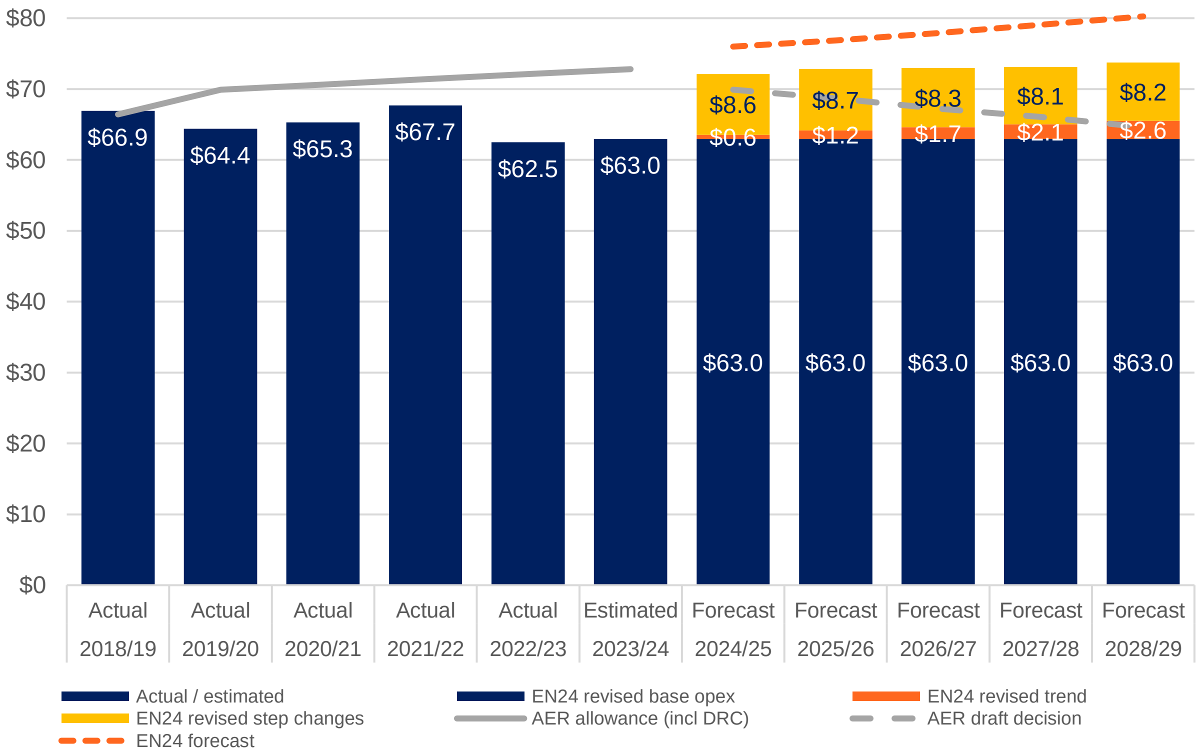
4. Our revised opex forecast

Evoenergy's revised opex forecast is $364.8 million, which is $25.3 million or 6.5 per cent lower than the initial proposal and $28.3 million or 8.4 per cent higher than the AER's draft decision. Evoenergy has revised its regulatory proposal[57] and has updated the opex forecast to incorporate more recently available information and address matters raised by the AER in the draft decision.[58]

Our revised opex forecast is prudent and efficient, developed consistently with the opex objectives set out in the NER, increasing by a mere average of 0.6 per cent in real terms each year over the forthcoming 2024–29 regulatory period. This is despite a significant uplift in regulatory obligations, cost pressures driven by international markets, and an evolving energy landscape with a transition to a net zero future and a decentralised energy system. Step changes to reflect an uplift in our obligations and changes in our operating landscape constitute 10.6 per cent of the total opex forecast. The revised forecast reflects the preferences of our customers.

The revised opex forecast has been developed to manage expected demand and comply with applicable regulatory obligations in delivering reliable services while maintaining the safety of the distribution system.[59] In developing the revised opex forecast, Evoenergy has had regard to the opex factors and objectives set out in the NER.[60] Historical opex for actuals, estimates, and forecasts are presented in Figure 11.

Figure 11 Evoenergy revised opex forecast ($ millions, 2023/24)



57 NER 6.10.3(a)

58 NER 6.10.3(b)

59 NER 6.5.6

60 NER, 6.6.6(e)

The revised opex forecast is shown by component in Table 13, and is separated into distribution and transmission services in Table 14.

Table 13 Revised proposal operating expenditure by component ($ millions, 2023/24)

Opex forecast	2024/25	2025/26	2026/27	2027/28	2028/29	Total
Base opex	$63.0	$63.0	$63.0	$63.0	$63.0	**$314.8**
Step changes	$8.0	$8.1	$7.7	$7.4	$7.6	**$38.8**
Trend	$0.6	$1.2	$1.7	$2.1	$2.6	**$8.2**
Debt raising costs	$0.6	$0.6	$0.6	$0.6	$0.6	**$3.1**
Opex forecast	**$72.1**	**$72.8**	**$73.0**	**$73.1**	**$73.8**	**$364.8**

Note: Base opex includes base year and final year incremental adjustments. Numbers may not add due to rounding. The opex forecast includes DRC.

Table 14 Forecast opex for distribution and transmission services ($ millions, 2023/24)

Opex forecast	2024/25	2025/26	2026/27	2027/28	2028/29	Total
Distribution	$60.7	$61.3	$61.5	$61.6	$62.1	**$307.2**
Transmission	$11.4	$11.5	$11.5	$11.5	$11.6	**$57.6**
Total opex	**$72.1**	**$72.8**	**$73.0**	**$73.1**	**$73.8**	**$364.8**

Note: Numbers may not add due to rounding. The opex forecast includes DRC.

5. Efficiency Benefit Sharing Scheme

The EBSS is designed to incentivise networks to pursue continuous opex efficiency improvements and share the benefits with consumers. The EBSS is intrinsically linked to the AER's preferred base-step-trend approach to forecasting opex.

Evoenergy's regulatory proposal included a negative EBSS revenue adjustment of $4.8 million, which excludes opex cost categories for debt raising costs, the demand management innovation allowance, and movements in provisions.[61]

The AER's draft decision was to not apply an EBSS carryover penalty to Evoenergy from the application of the EBSS in the current 2019–24 regulatory period as the AER did not adopt a revealed cost forecasting approach for the forthcoming 2024–29 regulatory period.[62] While the opex forecast is intended to work in tandem with a revealed cost forecasting approach, the AER considered our base 2021/22 opex as materially inefficient based on its benchmarking models. In the draft decision, the AER considered that Evoenergy would carry a greater share of losses than the AER initially intended when applying the EBSS to the current regulatory period, resulting in an outcome inconsistent with the NER objectives. As the AER considers that the base opex used to derive a forecast for the 2024–29 regulatory period was materially inefficient, it decided to not apply the EBSS.

We consider that our revised opex forecast is based on an efficient and updated 2022/23 base year and have included a the EBSS carryover for the forthcoming regulatory period. Evoenergy's revised regulatory proposal includes an EBSS revenue adjustment of $15.8 million, shown in Table 15, as we consider our revealed base year efficient. The supporting calculations to derive the revenue adjustment is included in the AER's standard EBSS model.

Table 15 Opex Efficiency Benefit Sharing Scheme ($ millions, 2023/24)

Revenue adjustment	2024/25	2025/26	2026/27	2027/28	2028/29	Total
Distribution EBSS	$4.1	$2.0	$2.7	$4.5	$0.0	**$13.3**
Transmission EBSS	$0.8	$0.4	$0.5	$0.8	$0.0	**$2.5**
Total EBSS	**$4.9**	**$2.3**	**$3.2**	**$5.3**	**$0.0**	**$15.8**

Note: Totals may not add due to rounding.

61 Evoenergy, Attachment 4 Incentive schemes, January 2023

62 Australian Energy Regulator, Draft Decision Evoenergy Electricity Distribution Determination 2024 to 2029 Attachment 8 Efficiency benefit sharing scheme, September 2023, pp. 1, 4