Draft decision

United Energy electricity distribution determination

1 July 2026 – 30 June 2031

Attachment 3 – Operating expenditure

September 2025

AUSTRALIAN ENERGY REGULATOR

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3 Operating expenditure

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

This attachment outlines our assessment of United Energy's proposed opex forecast for the 2026–31 regulatory control period (2026–31 period).

3.1 Draft decision

Our draft decision is to not accept United Energy's total opex forecast of $990.8 million,[1] including debt raising costs, for the 2026–31 period.[2] This is because our alternative estimate of $861.8 million is materially different ($129.1 million, or 13.0% lower) than United Energy's total opex forecast proposal. Therefore, we consider that United Energy's total opex forecast does not reasonably reflect the opex criteria.[3]

This material difference is primarily driven by not including, or including lower alternative estimates, for most of United Energy's proposed step changes, to reflect our assessment of efficient costs required for the 2026–31 period.

Our draft decision, which is less than United Energy's proposed total opex forecast, is:

- $37.6 million (–4.2%) lower than the opex forecast we approved for the 2021–26 regulatory control period (2021–26 period)
- $81.9 million (10.5%) higher than United Energy's actual (and estimated) opex in the 2021–26 period.

In Figure 3.1, we compare our alternative estimate of opex to United Energy's proposal for the next regulatory control period. We also show the forecasts we approved for the last 2 regulatory control periods, and United Energy's actual and estimated opex over these periods.

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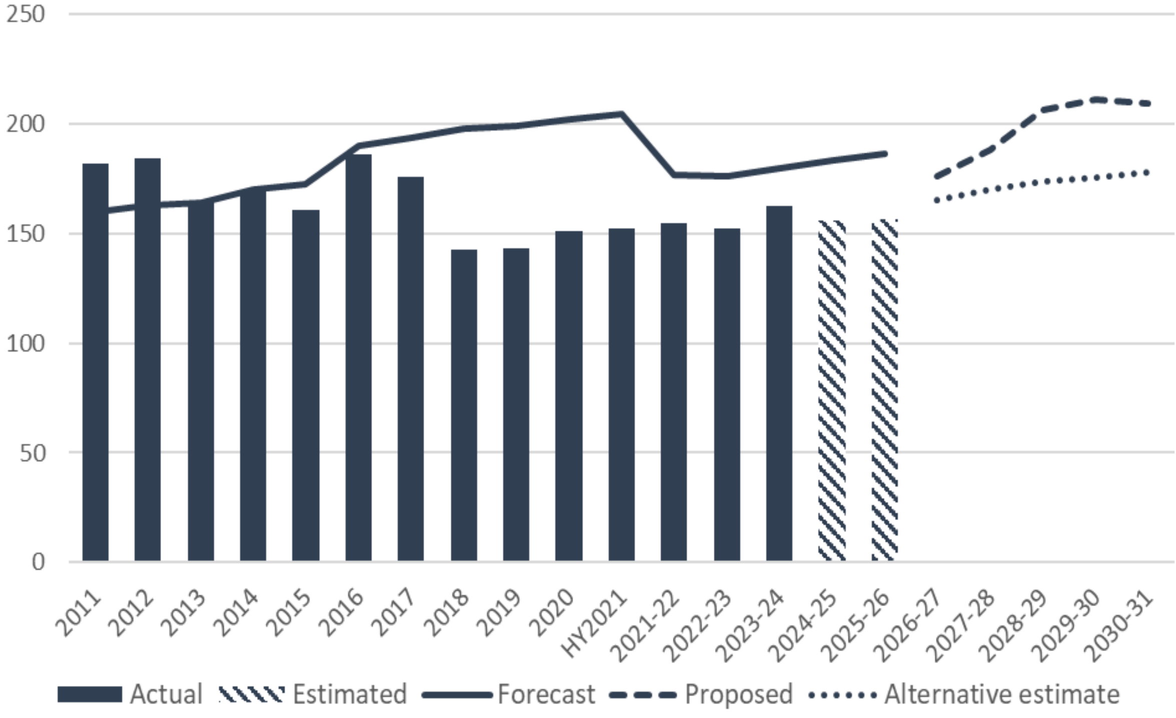
1 All dollars are in this document are in $2025–26 terms, unless otherwise stated.

2 United Energy, *Regulatory Proposal 2026–31 – Part B – Explanatory Statement*, January 2025, p. 75; United Energy, *UE MOD 1.05 – Opex*, January 2025.

3 National Electricity Rules (NER), cl. 6.5.6(c)–(e).

Figure 3.1 Historical and forecast opex ($million, 2025–26)



Source: United Energy, *Economic benchmarking – Regulatory Information Notice response 2010–24*; AER, *Final decision PTRM 2010–2015*; AER, Final decision PTRM 2015–20; AER, Final decision 2021–26 PTRM; United Energy, UE MOD 1.05 – opex, January 2025; AER analysis.

Table 3.1 sets out United Energy’s opex proposal, our alternative estimate for the draft decision and the differences between these forecasts.

Table 3.1 Comparison of United Energy's opex proposal and our alternative opex estimate ($million, 2025–26)

Category	United Energy proposal	AER draft decision	Difference $million (%)
Based on estimated opex in 2024–25	**779.2**	**778.9**	**–0.3**
2024–25 to 2025–26 increment	**14.8**	**14.8**	**0.0**
Remove category specific forecasts	**–9.1**	**–9.1**	**0.0**
Base year non-recurrent efficiency gain	**–**	**20.7**	**20.7**
Base year adjustment: licence fees	**–3.7**	**–3.7**	**0.0**
Trend: Output growth	15.8	7.9`	–7.9
Trend: Price growth	16.4	14.6	–1.8
Trend: Productivity growth	–11.8	–12.0	–0.2
Total trend	**20.4**	**10.5**	**–9.9**
Step change: customer assistance package *	14.7	–	–14.7
Step change: vegetation management	72.3	–	–72.3
Step change: CER integration	18.9	13.5	–5.5
Step change: Cloud services	24.3	3.9	–20.4
Step change: ICT modernisation and new capability	31.6	28.9	–2.7
Step change: Fleet electrification	–0.2	–0.2	–
Step change: Network and community resilience	4.4	–	–4.4
Step change: Insurance	–	–22.6	–22.6
Total step changes	**166.1**	**23.5**	**–142.6**
GSL	9.2	8.1	–1.2
Innovation Fund	6.0	1.7	–4.2
Customer assistance package	–	8.7	8.7
Debt raising costs	8.0	7.7	–0.2
Total category specific forecasts	**23.2**	**26.3**	**3.1**
Total	**990.8**	**861.8**	**–129.1 (–13.0)**

Source: United Energy, *UE MOD 1.05 – Opex*, January 2025; AER analysis.
Note: Numbers may not add up to total due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

The key differences between United Energy's opex proposal, which we have not accepted, and our alternative estimate are that we have:

- not included the following step changes:
  - vegetation management (–$72.3 million) – section 3.3.4.2
  - network and community resilience (–$4.4 million) – section 3.3.4.5

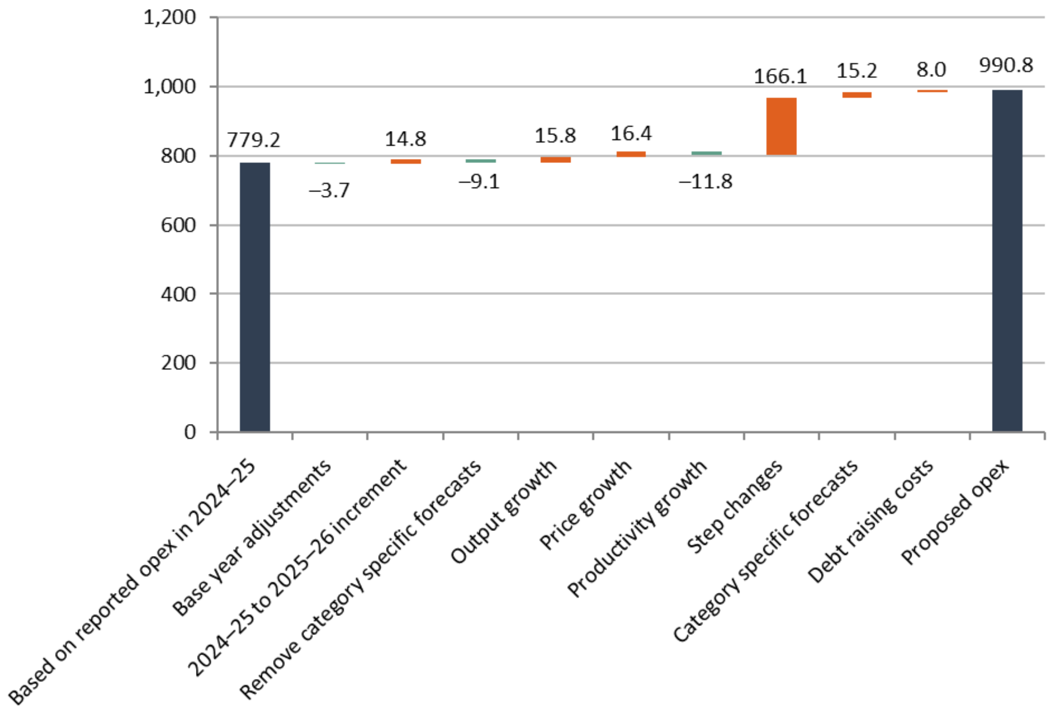
- included lower alternative estimates for the following step changes:
  - CER integration (–$5.5 million lower) – section 3.3.4.3
  - cloud services (–$20.4 million) – section 3.3.4.4
  - ICT modernisation and new capabilities (–$2.7 million) – section 3.3.4.4
- reclassified the customer assistance package step change as a category specific forecast, and included a lower alternative estimate (–$6.0 million) – section 3.3.4.1
- included a base year non-recurrent efficiency gain ($20.7 million) and new negative step change (–22.8$ million) to ensure the overestimated insurance premiums included in forecast opex for the current 2021–26 regulatory period don't impact forecast opex for the 2026–31 period. The net impact of these two adjustments reduces forecast total opex by $1.9 million – section 3.3.4.7
- substituted our output growth forecast (–$7.9 million) – section 3.3.3.2.

3.2 United Energy's proposal

United Energy's proposal applied a base–step–trend approach to forecast opex for the 2026–31 period, consistent with our standard approach.[4]

United Energy's approach to applying our base–step–trend approach is set out in Table 3.1. Figure 3.2 shows the different components that make up United Energy's opex forecast for the 2026–31 period.

Figure 3.2 United Energy's opex forecast ($million, 2025–26)



Source: United Energy, *UE MOD 1.05 – Opex*, January 2025

4 United Energy, *Regulatory Proposal 2026–31 – Part B – Explanatory Statement*, January 2025, p. 11.

3.2.1 Stakeholder views

We received 5 submissions that commented on United Energy's opex proposal: United Energy's Consumer Advisory Panel, Origin Energy, Victorian Greenhouse Alliances, Farmers for Climate Action, and the Consumer Challenge Panel subpanel 32 (CCP32).

Submissions did not raise strong issues related to United Energy's opex proposal, and were generally supportive. Submissions noted the electrification effort currently taking place in Victoria, and particularly noted the impact on demand and the interactions with consumer energy resources (CER) penetration on the networks. CCP32 queried whether some of United Energy's step changes met the Better Reset Handbook requirements for a step change, but concluded the vegetation management and customer assistance step changes were likely consistent with government and community expectations. CCP32 particularly noted the strong customer support for the customer assistance step change.[5]

The Greenhouse Alliance also recommended establishing a consistent methodology for CER expenditure proposals. It considered this would provide a more meaningful overview to consumers on these proposals.[6]

3.3 Reasons for draft decision

Our draft decision is to not accept United Energy's total opex forecast of $990.8 million, including debt raising costs, for the 2026–31 period. Our alternative estimate of $861.8 million is materially different ($129.1 million, or 13.0% lower) to United Energy's total opex forecast proposal. Therefore, we are not satisfied that United Energy's total opex forecast reasonably reflects the opex criteria, having regard to the opex factors.[7]

Table 3.1 sets out United Energy's proposal, our alternative estimate that has informed this draft decision, and the difference between our alternative estimate and the proposal.

The main drivers for this difference are also set out in section 3.1, and we discuss each of the components of our alternative estimate, and our assessment of United Energy's proposal, below. Full details of our alternative estimate are set out in our opex model, which is available on our website.

3.3.1 Base opex

This section provides our view on the prudent and efficient level of base opex that we consider United Energy would need for the safe and reliable provision of network services over the 2026–31 period.

5 CCP32, *Submission – United Energy electricity distribution proposal 2026–31*, May 2025, pp. 24-25.

6 Victorian Greenhouse Alliances, *Submission – Victorian electricity distribution proposals 2026–31*, May 2025, pp. 16–17.

7 NER, cl. 6.5.6(c)–(e).

3.3.1.1 Proposed base year

United Energy proposed a base year of 2024–25, and base year opex of $155.8 million. This equates to $779.2 million over the 5 years of the next regulatory control period. [8]

United Energy's base year estimated opex is $26.9 million (–14.7%) lower than the forecast opex approved for that year, and $0.1 million lower than the average actual opex over the period 2021–22 to 2023–24.

United Energy submitted that 2024–25 is the most suitable base year because it will be the most recent year where audited actual data will be available at the time of our final decision.[9]

While there will be year to year fluctuations in reported opex over the current regulatory period, due to the interaction with the EBSS, we do not generally have concerns with the choice of base year, provided we find United Energy's opex in the base year to be efficient.

In our alternative estimate for the draft decision, we have included a minor update to the 2024–25 base opex amount, for a total of $778.9 million over the next regulatory control period. This is because we have used the latest inflation values to convert the nominal amount into real terms. We have used the actual inflation for the year to August 2025, from the Australian Bureau of Statistics, and the Reserve Bank of Australia's forecast of inflation for the year to June 2026, from its August Statement on monetary policy.[10] These inflation forecasts were not available at the time of United Energy's initial proposal, and represent the best available forecast, because they are the most up-to-date information available at this time.

3.3.1.2 Efficiency of United Energy's opex

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

We consider United Energy's estimate of its opex in 2024–25 is not materially inefficient, as indicated by its opex trend over time and our benchmarking results. Accordingly, we have used United Energy estimated costs in 2024–25 to develop our alternative estimate.

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8 United Energy, *Regulatory Proposal 2026–31 – Part B – Explanatory Statement*, January 2025, p. 76; United Energy, *UE MOD 1.05 – Opex,* January 2025.

9 United Energy, *Regulatory Proposal 2026–31 – Part B – Explanatory Statement*, January 2025, p. 76.

10 Australian Bureau of Statistics (ABS), *Consumer Price Index, Australia, released on 31 July 2024* (accessed on 31 July 2024: https://www.abs.gov.au/statistics/economy/price-indexes-and-inflation/consumer-price-index-australia/latest-release); Reserve Bank of Australia, *Statement on monetary policy*, *August 2024*, (accessed on 6 August 2024: https://www.rba.gov.au/publications/smp/2024/aug/outlook.html#3-5-detailed-forecast-information).

In terms of the trend in opex, Figure 3.1 shows United Energy's opex forecast for the next regulatory control period, its actual opex in previous regulatory control periods and our previous regulatory decisions.

Overall, United Energy's opex has been historically lower than our approved forecast since 2015–16. United Energy's estimated opex in the base year (2024–25) of $155.8 million is $26.9 million (–14.7%) below the approved forecast opex for that year.

In line with our standard approach, we have used our benchmarking tools and other cost analysis to assess and establish whether United Energy is operating relatively efficiently, both over time and in the base year. We conclude that United Energy performs well compared to other networks and is not materially inefficient.

As set out in more detail in past decisions,[11] in assessing base opex efficiency, our standard approach is to benchmark a business' efficiency on the basis of its average efficiency over time (using a period-average efficiency score from our econometric opex cost function models). We consider that this is the appropriate place to start, rather than initially looking at the efficiency of a single year (such as the base year), as this recognises that opex is generally recurrent, but with some degree of year-to-year volatility. Reflecting our conservative approach, we use a 0.75 benchmark comparison point (rather than 1.0) to assess the relative efficiency of distribution businesses.

Our benchmarking results indicate that United Energy has been amongst the more productive and efficient distributors in the National Electricity Market (NEM).[12] In particular, as shown in Figure 3.3 for the 2006–23 period, United Energy remains a benchmark comparator business, with an econometric model-average score across the 2006–23 period of 0.95, and the 2012–23 period of 0.88, which are well above our benchmark comparison point of 0.75.

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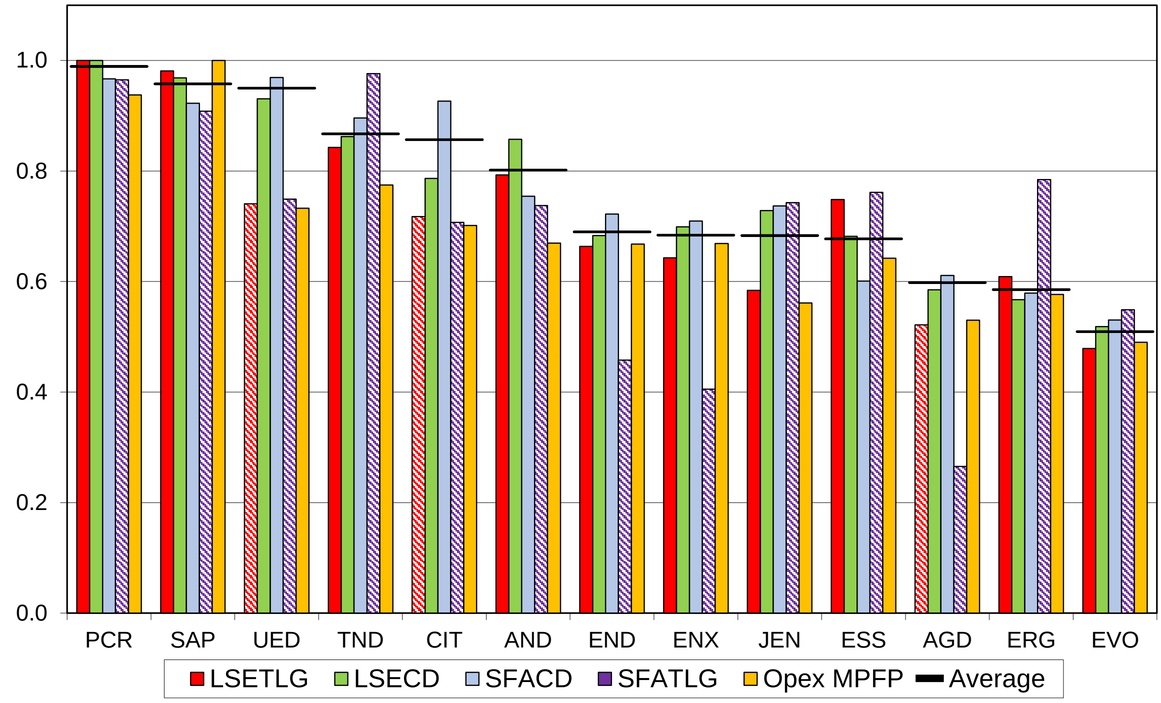
11 AER, *Final Decision, Attachment 6 – Operating expenditure – Ergon Energy – 2025–30 Distribution determination revenue proposal,* April 2025, pp. 17–23.

12 AER, *2024 Annual Benchmarking Report – Electricity distribution network service providers*, November 2024, pp. 26–28.

Figure 3.3 Econometric opex efficiency scores and opex MPFP, 2006–23

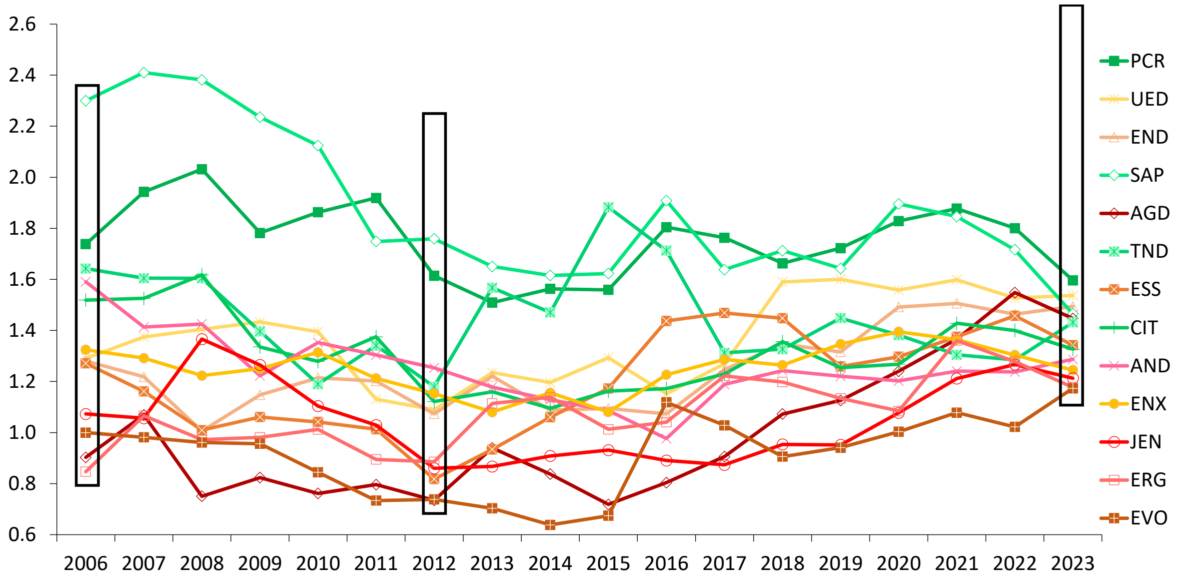


Source: AER, *2024 Annual Benchmarking Report – Electricity distribution network service providers, November 2024*, p. 35.

Note: Columns with a hatched pattern represent results that violate the key property that an increase in output is achieved with an increase in cost. These results also do not reflect the impact of a range of material OEFs (see section 7). Opex MPFP scores for each distribution business are displayed for comparison and are not included in the calculation of the average efficiency score, which also excludes any results affected by monotonicity violations.

We also use productivity index number techniques to enable comparisons of productivity levels over time and between distribution businesses. The multilateral total factor productivity index measures the total factor productivity of each business over time, whereas the opex and capital multilateral partial factor productivity (MPFP) indexes measure the productivity of opex or capital inputs respectively. Our opex MPFP efficiency results are also not adjusted for material operating environment factors. As shown in Figure 3.4, United Energy has generally been among the top performing distribution businesses in opex MPFP throughout the period.

Figure 3.4 Individual distribution business opex MPFP indexes, 2006–23



Source: AER, *2024* Annual Benchmarking Report – Electricity distribution network service providers, November 2024, p. 28.

We consider that these results warrant the use of revealed costs in 2024–25 as the base year in our alternative estimate, as it provides an efficient base from which to form the 2026–31 period opex allowance.

3.3.2 Adjustments to base year opex

United Energy proposed the following adjustments to its base year opex:[13]

- add $3.0 million for the increase in opex between base year 2024–25 and the final year 2025–26 (the final year increment). This is consistent with our standard approach, and we have made the same adjustment in our alternative estimate. This increases our alternative estimate by $14.8 million over the 5 years of the 2026–31 period.
- remove $1.8 million from the estimated final year opex for the removal of opex categories forecast separately. We have made the same adjustment in our alternative estimate. This decreases our alternative estimate by $9.1 million over the 5 years of the 2026–31 period.
- remove $0.7 million from the estimated final year opex for licence fees. These costs will be recovered as a jurisdictional scheme from 2025–26. We have made the same adjustment. This reduces our alternative estimate by $3.7 million over the 5 years of the 2026–31 period.

We have also included a base year non-recurrent efficiency gain in our alternative estimate, relating to the insurance premiums step change we approved in the current regulatory control period. This adds the difference between the forecast of insurance premiums reflected in the approved step change and actual insurance premiums in the base year, which is equal to $4.1 million. This increases our alternative estimate by $20.7 million over 5 years. We also

13 United Energy, *UE MOD 1.05 – Opex*, January 2025.

added a negative step change for insurance premiums. We discuss both adjustments, including the reasons for them, in section 3.3.4.7.

3.3.3 Rate of change

Having determined an efficient base year opex and estimated final year opex by adding a final year increment, we trend forward estimated final year opex to account for the forecast growth in prices, output and productivity over the regulatory control period. We refer to this as the rate of change.[14]

United Energy largely applied our standard approach to forecast the rate of change, including:[15]

- **Price growth:** adopting our standard input price weightings of 59.2% labour and 40.8% non-labour. It forecast labour price growth using an average of forecasts of the growth in the wage price index (WPI) from BIS Oxford Economics (its consultant) and Deloitte (our consultant) as a placeholder.
- **Output growth:** applying the output weights from our 4 econometric models, consistent with our standard approach. It applied these weights to its forecasts of the growth in its customer numbers, circuit length and ratcheted maximum demand.
- **Productivity growth:** using our 0.5% per year productivity growth forecast.

The rate of change proposed by United Energy contributed $20.4 million (2.1% of total forecast opex) to United Energy's total opex forecast of $990.8 million. This equates to an average opex increase of 1.0% each year. We have included a rate of change that contributes $10.5 million (1.2% of total forecast opex) to our alternative estimate of total forecast opex of $861.8 million. This equates to an average opex increase of 0.5% each year in our alternative estimate.

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[14] AER, *Final decision, Expenditure forecast assessment guideline – electricity distribution*, October 2024, pp. 22–24.

[15] United Energy, *Regulatory Proposal 2026-31 – Part B – Explanatory Statement*, January 2025, pp. 77–78; United Energy, *UE MOD 1.05 – Opex*, January 2025.

Table 3.2 Forecast annual rate of change in opex (%)

	2026–27	2027–28	2028–29	2029–30	2030–31
United Energy's proposal					
Price growth	0.9	0.5	0.6	0.7	0.7
Output growth	0.5	0.6	0.6	0.8	1.8
Productivity growth	0.5	0.5	0.5	0.5	0.5
Rate of change	**0.9**	**0.6**	**0.7**	**1.0**	**2.0**
AER alternative estimate					
Price growth	0.5	0.6	0.7	0.7	0.7
Output growth	0.3	0.3	0.3	0.3	0.5
Productivity growth	0.5	0.5	0.5	0.5	0.5
Rate of change	**0.4**	**0.4**	**0.5**	**0.5**	**0.7**
Difference	**–0.5**	**–0.2**	**–0.2**	**–0.5**	**–1.3**

Source: United Energy, *UE MOD 1.05 – Opex*, January 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small nonzero amounts and '–' represents zero.

3.3.3.1 Forecast price growth

United Energy proposed average annual price growth of 0.7%, which increased its total opex forecast by $16.4 million. We have used real average annual price growth of 0.6% in our alternative estimate of total opex. This increases our total opex estimate by $14.6 million.

Both we and United Energy forecast price growth as a weighted average of forecast labour price growth and non-labour price growth (real price growth rate of zero), using weights of 59.2% and 40.8% respectively.

Consequently, the key differences between our real price growth forecasts and United Energy's are that:

- we have updated our labour price growth forecast to include more recent forecasts from our consultant, Deloitte Access Economics
- we have not included a superannuation increase in 2026–27 in our labour price growth rates, since the final superannuation guarantee increase is in 2025–26.

Table 3.3 compares our forecast labour price growth with United Energy's proposal.

Table 3.3 Forecast labour price growth (%)

	2026–27	2027–28	2028–29	2029–30	2030–31
United Energy's proposal					
Deloitte Access Economics	0.8	0.7	0.8	1.1	1.1
BIS Oxford Economics	1.2	1.0	1.3	1.3	1.2
Average	1.0	0.9	1.0	1.2	1.1
Superannuation guarantee increases	0.5	–	–	–	–
Average, including super guarantee	1.5	0.9	1.0	1.2	1.1
AER alternative estimate					
Deloitte Access Economics	0.7	0.9	1.1	1.1	1.0
BIS Oxford Economics	1.2	1.0	1.3	1.3	1.2
Average	0.9	0.9	1.2	1.2	1.1
Overall difference	**–0.6**	**0.1**	**0.1**	**0.0**	**0.0**

Source: United Energy, *UE MOD 1.05 – Opex*, January 2025; Deloitte Access Economics, *Labour price growth forecasts*, 20 August 2024, p. 10; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

For the final decision, we will update the WPI forecasts with the most recent forecasts available from our consultant.

3.3.3.2 Forecast output growth

United Energy proposed average annual output growth of 0.9%, which increased its proposed opex forecast by $15.8 million. We have forecast average annual output growth of 0.4%. This increases our alternative estimate of total opex by $7.9 million, which is $7.9 million less than United Energy's proposal.

Customer numbers growth

We are not satisfied that United Energy's forecast growth rates for customer numbers reflect a realistic expectation. We have used the customer numbers forecast in Table 3.4.

Table 3.4 Forecast growth in customer numbers, %

	2026–27	2027–28	2028–29	2029–30	2030–31
United Energy's proposal	1.2	1.3	1.4	1.5	1.6
AER alternative estimate	0.7	0.7	0.7	0.7	0.7
Difference	**–0.5**	**–0.6**	**–0.7**	**–0.8**	**–0.9**

Source: United Energy, *UE MOD 1.05 – Opex*, January 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

United Energy used population growth, taken from *Victoria in Future 2023*, to forecast customer numbers growth. It stated that customer numbers growth was correlated to population growth.[16] While customer numbers growth is correlated to population growth, the relationship is not one for one in United Energy's network area, as shown in Figure 3.5. Historically, customer numbers have grown by 0.48% when population has grown by 1% (this excludes the years from 2020, which were impacted by COVID). We have corrected forecast customer numbers to reflect this relationship.

Figure 3.5 Historic customer numbers growth and population growth, %

Source: United Energy, *Response to information request IR#019*, 5 May 2025; AER analysis.

Circuit length growth

We are satisfied that United Energy's forecast circuit length, as set out in Table 3.5, reflects a realistic expectation. This forecast is consistent with the circuit length forecast United Energy provided in its reset Regulatory Information Notice (RIN) and is similar to actual growth rates in recent years.

Table 3.5 Forecast growth in circuit length, %

	2026–27	2027–28	2028–29	2029–30	2030–31
United Energy's proposal	0.2	0.2	0.2	0.2	0.2
AER alternative estimate	0.2	0.2	0.2	0.2	0.2
Difference	–	–	–	–	–

Source: United Energy, *UE MOD 1.05 – Opex*, January 2025; AER analysis.

16 United Energy, *Response to information request IR#019*, 5 May 2025, p. 2.

Note: Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

Ratcheted maximum demand growth

We are not satisfied that United Energy's forecast growth rates for ratcheted maximum demand reflect a realistic expectation. We have used the ratcheted maximum demand forecast in Table 3.6.

Table 3.6 Forecast growth in ratcheted maximum demand, %

	2024–25	2024–25	2025–26	2026–27	2027–28
United Energy's proposal	–	–	–	0.5	2.8
AER alternative estimate	–	–	–	–	0.6
Difference	**–**	**–**	**–**	**–0.5**	**–2.2**

Source: United Energy, *UE MOD 1.05 – Opex*, January 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

The maximum demand forecasts that United Energy used in its opex model were different to those that United Energy included in its reset RIN.[17] We asked United Energy why it did not use the demand forecast in its reset RIN, and it stated that it used its actual maximum demand in 2023–24 escalated by the forecast growth rates in its reset RIN, plus half the L.E.K. Consulting forecast of new data centre capacity over 2027–31.[18] It did not provide a reason for doing this.

We engaged Baringa to review United Energy's maximum demand forecasts, and it noted that United Energy had treated the L.E.K. Consulting data centre demand forecasts inconsistently across its forecasts. Baringa considered that United Energy's approach of only including data centres that are committed and contracted in the maximum demand forecasts in its reset RIN was reasonable. Baringa considered that data centres that are yet to be contracted should be excluded from the forecasts.[19] We agree that there is insufficient certainty to include the L.E.K. Consulting data centre demand forecasts in the maximum demand forecasts, and have therefore not included them in the forecast ratcheted maximum demand component of our alternative output growth estimate.

We also have concerns with how United Energy included non-data centre block loads, which we consider double counts loads captured in the trend and other components of the modelling. The block load register provided by United Energy included blocks that are substantially lower than the loads of large customers. It may be appropriate to include a block at a particular asset (for example, at the feeder level), but when forecasting demand at the system level, this load may be captured by the trend growth factor (such as population growth or economic growth). We are not satisfied that United Energy sufficiently accounted for the potential overlap between block loads and other components of the modelling for

[17] Specifically, we use non-coincident maximum demand, 50% PoE, forecast at the transmission connection point in MW.

[18] United Energy, *Response to information request IR#019*, 5 May 2025.

[19] Baringa, *Distribution demand forecast assessment, Review of United Energy's 2026–31 regulatory proposal*, July 2025, pp. 8–9.

system-level demand, because it was limited to population-driven block loads. Baringa raised similar concerns, noting that the approaches to block loads at the spatial level compared to the system level, and how they reconcile to each other, was unclear.[20]

We invite United Energy to update its demand forecasts for its revised proposal.

3.3.3.3 Forecast productivity growth

United Energy proposed average productivity growth of 0.5% per year, which decreased its total opex by $11.8 million. We have forecast the same average productivity growth rate, which reflects our standard approach.[21] This decreases our alternative opex estimate by $12.0 million over the 2026–31 period.

3.3.4 Step changes

In developing our alternative estimate for the draft decision, we include prudent and efficient step changes for cost drivers such as new regulatory obligations or efficient capex / opex trade-offs. As we explain in the Guideline, we will generally include a step change if the efficient base opex and the rate of change in opex of an efficient service provider does not already include the proposed cost for such items, and they are required to meet the opex criteria.[22]

United Energy's proposal included 7 step changes totalling $166.1 million, or 20.1% of its proposed total opex forecast.[23] These are shown in Table 3.7 along with our alternative estimate for the draft decision, which is to include step changes totalling $23.5 million. This is $142.6 million lower than United Energy's proposal. While we consider most of these step changes to be prudent, we are not satisfied they reflect the efficient level of expenditure, hence our lower estimate in most cases.

We have also included an additional negative step change to ensure the overestimated insurance premiums included in forecast opex for the current 2021–26 don't impact forecast opex for the 2026–31 period.

We discuss our assessment of each step change below.

Table 3.7 United Energy's proposed step changes and the AER's alternative estimate ($million, 2025–26)

Step change	United Energy's proposal	AERs alternative estimate	Difference
Customer assistance package	14.7	–	–14.7
Vegetation management	72.3	–	–72.3

20 Baringa, *Distribution demand forecast assessment, Review of United Energy's 2026–31 regulatory proposal*, July 2025, p. 33.

21 AER, *Opex productivity growth review 2018 – Final decision*, 8 March 2019.

22 *AER,* Final decision, Expenditure forecast assessment guideline – electricity distribution*, October 2024*, pp. 24–25.

23 United Energy, *Regulatory Proposal 2026-31 – Part B – Explanatory Statement*, January 2025, pp. 79–81.

Step change	United Energy's proposal	AERs alternative estimate	Difference
CER integration	18.9	13.5	–5.5
Cloud services	24.3	3.9	–20.4
ICT modernisation	31.6	28.9	–2.7
Network and community resilience	4.4	–	–4.4
Fleet electrification	–0.2	–0.2	–
Insurance	–	–22.5	–22.5
Total step changes	**166.1**	**23.5**	**–142.6**

Source: United Energy, *UE MOD 1.05 – Opex*, January 2025; AER analysis.

3.3.4.1 Customer assistance package

United Energy proposed $14.7 million (1.5% of forecast opex) for its customer assistance package, which aims to improve services to customers experiencing vulnerability.[24] The package combines 5 programs, as follows:[25]

- Energy Care ($1.4 million)
- Community Energy Fund ($3.5 million)
- Vulnerable Customer Assistance Program ($4.3 million)
- Energy Advisory Services ($1.5 million)
- First Peoples Program ($4.0 million).

Based on our review, we have included a lower amount of $8.7 million for the customer assistance package in our alternative estimate of total opex. This is 41% lower than United Energy's proposal. We have also treated this as a category specific forecast. Our alternative forecast of annual costs is provided in the category specific forecast section 3.3.5.3.

Table 3.8 United Energy's customer assistance step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
United Energy's proposal	2.9	2.9	2.9	3.0	3.0	14.7
AER alternative estimate	–	–	–	–	–	–
Difference	**–2.9**	**–2.9**	**–2.9**	**–3.0**	**–3.0**	**–14.7**

Source: United Energy, *UE MOD 1.05 - Opex*, January 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

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24 United Energy, *UE BUS 9.02 – Customer assistance package*, January 2025, p. 5.

25 United Energy, *UE MOD 9.03 – Opex step changes*, January 2025

Assessment

We have had regard to United Energy's consumer engagement in our assessment of the customer assistance package. We note that the customer assistance package was developed with input from, and is strongly supported by, both customers and United Energy's Consumer Advisory Panel (CAP). For example, the CAP submitted:[26]

> *We are particularly pleased about increases in the regional and rural supply program and the customer assistance package, as well as the commitment to create a vulnerability strategy with an emphasis on partnerships with community organisations who already support people in vulnerable circumstances.*

The CAP emphasised that United Energy should adopt a partnership-based approach, underpinned by a vulnerability strategy, and focus on areas where it is uniquely positioned to have the greatest impact in assisting vulnerable customers on its network.[27] We agree these are important factors in considering whether the proposed costs are prudent, efficient, and provide incremental benefits to consumers.

Vulnerable customer costs do not meet our standard step change categories (i.e. new regulatory obligation, capex/opex trade-off, material change in external market factors). However, we recognise these programs represent new incremental costs (not covered by base/trend opex) and we have provided for similar costs in other recent determinations on the basis of strong customer support and detailed analysis. We also note the Consumer Challenge Panel's view that:[28]

> *strong customer support, along with regulator and government expectations, are close enough to meeting step change criteria for this proposal to be actively considered.*

We have assessed each proposed program separately, based on the cost breakdown provided by United Energy in its step change model, as well as the objectives of each program outlined in the proposal. We set out our conclusions on each program, which forms part of the overall vulnerable customer package step change below. The key considerations we have had regard to in our assessment are whether the proposed programs align with a partnership-based approach to assisting vulnerable customers, are not duplicative of existing programs or costs, and reflect activities where a distribution network is specifically or uniquely well placed to assist.

We further consider that vulnerable customer package costs should be treated as a category specific forecast, rather than an opex step change. This treatment is consistent with our approach in recent determinations, and means incurred costs will not be automatically rolled into base opex. We consider a review of the outcomes of the programs, with ongoing input and oversight from consumers, is warranted.

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[26] Customer Advisory Panel, *CPU Customer Advisory Panel – Submission – United Energy electricity distribution proposal 2026–31*, April 2025, p. ii.

[27] Customer Advisory Panel, *CPU Customer Advisory Panel – Submission – United Energy electricity distribution proposal 2026–31*, April 2025, pp. 3, 26–27, 33.

[28] CCP32, *Submission – United Energy electricity distribution proposal 2026–31*, May 2025 p. 25.

Table 3.9 summarises United Energy's proposal for its customer assistance package, our alternative estimates, and draft decisions for each program. As the 3 businesses CitiPower, Powercor and United Energy proposed essentially the same programs for the customer assistance package across each network, the full detail of our reasoning for these draft decision positions is in the CitiPower and Powercor draft decision opex attachments.

Table 3.9 Customer assistance package draft decision summary ($million, 2025–26)

Program	Proposal	Alternative Estimate	Draft Decision	Comment
Energy Care	1.4	0.4	Partially accepted	Accept costs for partnership delivery and areas of unique positioning, avoiding duplication
Community Energy Fund	3.5	–	Not accepted	United Energy is not uniquely positioned to provide this service. Overlap with other organisations
Vulnerable Customer Assistance Program	4.3	4.3	Accepted	Accept as a placeholder; subject to United Energy confirming CAP support detailed program costs
Energy Advisory Service	1.5	–	Not accepted	Not a new service; potential double-counting with CER Data Visibility program
First Peoples Program	4.0	4.0	Accepted	Accept as a placeholder; seek further evidence that FPAC supports net benefits of program
Total	**14.7**	**8.7**	**41% reduction**	

Source: United Energy, *UE MOD 1.05 – Opex*, January 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of

3.3.4.2 Vegetation management

United Energy proposed a $72.3 million step change (7.3% of forecast total opex), for increased vegetation management costs.[29] We have not included a step change for vegetation management in our alternative estimate of total opex. United Energy has made substantial progress in addressing vegetation management compliance issues over the last 2 years. We consider based on the information available that United Energy's total base opex, and the rate of change, provides sufficient opex for United Energy to comply with its electric line clearance obligations in the 2026–31 period. This view is based on our own independent analysis, which aligns with, and is supported by, EMCa's advice. We expect United Energy to consider our feedback, and account for updated base year expenditure and the current status of its cutting program, when considering its revised proposal.

[29] United Energy, *UE MOD 1.05 – Opex*, January 2025.

Table 3.10 Vegetation management step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
United Energy's proposal	7.1	10.8	17.8	18.1	18.4	**72.3**
United Energy's amended forecast	12.7	15.8	16.0	16.1	16.2	**76.8**
AER alternative estimate	–	–	–	–	–	**–**
Difference	**–7.1**	**–10.8**	**–17.8**	**–18.1**	**–18.4**	**–72.3**

Source: United Energy, *UE MOD 1.05 – Opex*, January 2025; United Energy, *Response to information request IR014*, 22 April 2025; AER analysis.

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

United Energy's proposal

United Energy stated that in recent years it has introduced helicopter mounted LiDAR technology to inspect its electricity lines for compliance against its obligations under the Electricity Safety (Electric Line Clearance) Regulations. Prior to using LiDAR, it relied on visual inspections. It stated that using LiDAR provides increased accuracy and precision that has shown previously unidentified non-compliance. It stated it needs increased opex (as a step change) to address this non-compliance.[30] Of note, Jemena and AusNet, which are subject to the same regulations, did not proposed similar step changes for vegetation management.

We have identified several concerns with the proposed vegetation management step change. While we consider that United Energy will need to make further improvements to its vegetation management practices to ensure compliance with its vegetation management obligations, we are not satisfied, based on the evidence provided, that an increase in opex beyond that provided in base opex and the rate of change is required.

In response to an information request, United Energy provided an amended forecast of its vegetation management step change to reflect more up to date information.[31] We have based our assessment on this more recent forecast.

Stakeholder engagement on the vegetation management step change

United Energy stated that it designed its regulatory proposals with Victorian electricity consumers in mind, and had consulted on this step change with its CAP. It stated that the CAP was supportive of it receiving additional expenditure to comply with its safety related regulatory obligations, and in turn minimise bushfire risk.

The CCP32, however, stated that if the need for increased opex was due to United Energy underspending consistently over recent years, and needing to get back to the levels forecast, then this would not be a reason for a step change. Otherwise, it considered a step change may be appropriate, subject to the appropriate level being considered by the AER.

30 United Energy, *UE ATT 9.02 – Vegetation management step change*, January 2025, pp. 2–4.

31 United Energy, *Response to information request IR014*, 22 April 2025.

The Victorian Greenhouse Alliances considered that the DNSPs should be required to implement more frequent pruning cycles, to reduce unnecessary destruction of mature trees.

United Energy's regulatory obligations

United Energy's regulatory obligations are set by the *Electricity Safety Act 1998*, and the Electricity Safety (Electric Line Clearance) Interim Regulations 2025. The Code of Practice for Electric Line Clearance is a schedule to the Regulations.

There has been no substantive change to the Electric Line Clearance Regulations or the Code of Practice in the 2021–26 period. The current Regulations are due to expire on 25 June 2026. We are not expecting the new regulations to include any material changes from the existing regulations or the Code of Practice.

Although there has been no change to the regulations, United Energy submitted that it is subject to a new regulatory obligation. It stated that it is now using LiDAR technology to inspect vegetation clearances, and this is identifying non-compliance that it was not able to identify previously. Once it identifies non-compliance, it must address that non-compliance. United Energy stated that this has the effect of increasing the standard of compliance.[32]

As required under the Regulations, United Energy prepared and submitted to Energy Safe Victoria a management plan in September 2022 outlining how it will comply with the Code.[33] United Energy noted that the Regulations require that it 'must not contravene a requirement of the management plan if the management plan is approved by Energy Safe Victoria' (ESV). Consequently, United Energy stated that once its management plan was approved by ESV it became a regulatory obligation.[34]

Regardless of whether the management plan itself is a regulatory obligation, we are satisfied that United Energy must meet all the requirements of its plan. Accordingly, the forecast total opex we approve must be sufficient for United Energy to meet all the requirements in its approved management plan, as well as its regulatory obligations under the relevant Act, Regulations and Code of Practice.

United Energy also noted that it 'was prosecuted for the first time in 2023' for Code non-compliance, as well as receiving a number of fines. It stated this reflects the higher standard of compliance now required.[35]

EMCA's assessment

We engaged EMCa to provide an expert view on United Energy's proposed vegetation management step change. EMCa was satisfied that LiDAR data has identified additional

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32 United Energy, *UE ATT 9.02 – Vegetation management step change, January 2025*, p. 10.

33 CitiPower, Powercor and United Energy, *UE ATT 9.04 – 2021–2026 Electric Line Clearance (Vegetation) Management Plan*, September 2022.

34 United Energy, *UE ATT 9.02 – Vegetation management step change*, January 2025, p. 10.

35 United Energy, *UE ATT 9.02 – Vegetation management step change*, January 2025, p. 7.

cutting is required for United Energy to meet its obligations. However, EMCa's other key points were:[36]

- indications from data provided by United Energy that the LiDAR program has identified a smaller vegetation management program than what United Energy has proposed
- the cutting volume for 2024–25 is higher than the estimate relied upon by United Energy to forecast the uplift in volumes it requires. When combined with a smaller total volume to achieve compliance, this means United Energy has overestimated the uplift it requires
- a lack of justification for the proposed uplifts in contractor liaison and hazard trees costs
- unit rates are amongst the highest in Victoria, and higher than the revealed costs, without sufficient justification
- relatively new application of LiDAR technology, which amongst other things will require several years to be refined including updating of the vegetation management systems to establish a stable vegetation management program. Once stabilised, this can be expected to enable efficiencies to be realised which are not currently included in the forecast of opex requirements. EMCa considers these efficiencies can be material.

EMCa undertook sensitivity analysis and found that only conservative corrections to the underlying assumptions resulted in the need for the step change falling away. Given this, EMCa concluded that United Energy does not need a step change in opex to comply with its vegetation management obligations.

Our assessment of United Energy's vegetation management step change

EMCa's findings are broadly consistent with our own analysis. We found several flaws in the United Energy modelling that suggest the opex required for it to comply with its vegetation management obligations cannot be justified on the current information. We also have concerns that the proposed step change may be inconsistent with the intended opex incentive framework.

Overall, we have considered whether United Energy's base year expenditure, plus the rate of change, is sufficient for it to comply with its regulatory obligations. United Energy's proposed base year is 2024–25.

We have assessed United Energy's vegetation management from both a top-down perspective as well as doing a bottom-up assessment. In terms of our top-down assessment, we looked at United Energy's vegetation management costs over time. We also looked at how United Energy's vegetation management opex compared to its Victorian peers, who operate under the same regulatory framework, albeit in different parts of Victoria.

United Energy has reduced its vegetation management opex over the past 15 years

We note that United Energy's vegetation management opex rose significantly from 2011, as shown in Figure 3.6. This followed a significant increase in its obligations imposed following the Black Saturday bushfires in 2009. From 2013, United Energy reduced its vegetation management opex. After introducing its LiDAR program, and identifying significant

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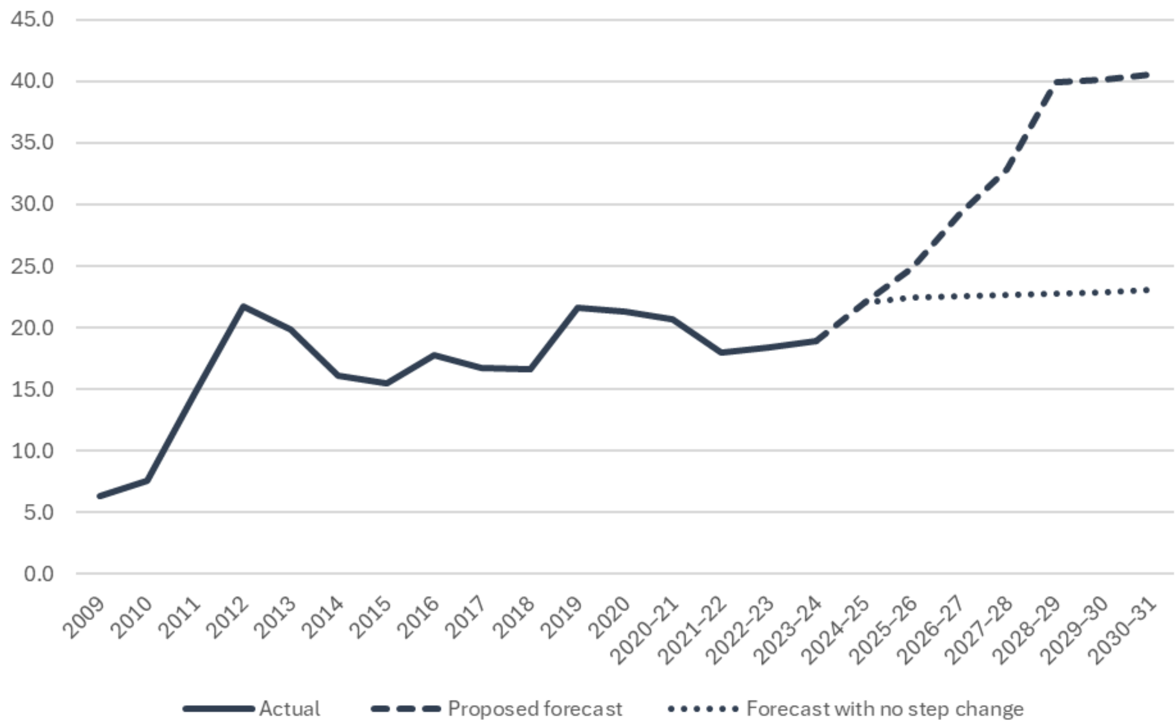
36 EMCa, *United Energy 2026–2031 Regulatory Proposal, Review of certain aspects of proposed expenditure on augex and vegetation management*, August 2025, pp. 55–58.

non-compliance, United Energy's vegetation management opex started to increase from around 2022–23.

United Energy's forecast vegetation management opex for the 2026–31 period is 79% more than its actual and estimated vegetation management opex for the 2021–26 period, and 94% more than the 2016–2020 period.

Without a step change, base year vegetation opex, plus the rate of change, would provide United Energy 11% more than its actual and estimated vegetation management opex for the 2021–26 period, and 21% more than the 2016–2020 period.

Figure 3.6 United Energy's vegetation management opex ($million, 2025–26)



Source: United Energy, *Category analysis RINs, Table 2.1.2*; AER analysis.

Our bottom-up assessment shows that United Energy has overestimated the opex required to comply with its regulatory obligations

In addition to this top-down analysis, we also looked closely at the model United Energy used to forecast its vegetation management step change.[37] We have identified concerns with several of the underlying assumptions.

The model forecasts the number of spans to be cut each year. This included both regular maintenance cuts and rectification cuts, which are required when vegetation is found within the minimum clearance space. It applied different unit rates to these volumes, with rectification cuts typically more expensive. For spans in a high bushfire risk area (HBRA) United Energy separately forecast cuts made in the fire danger period and those outside the

37 United Energy, *Response to information request IR#014*, 22 April 2025.

fire danger period. This is because United Energy's management plan requires it to cut non-compliant spans quicker within the fire danger period.

As noted by EMCa, United Energy proposed a volume of cutting that is significantly higher than its own LiDAR program identified as necessary in 2024. United Energy provided information showing that had it completed its full program of maintenance cuts in 2024, and cleared all spans that were found to have vegetation in the minimum clearance space, it would have needed to do 39,357 cuts. However, United Energy proposed to increase the number of cuts to around 43,080 from 2027–28. We have identified 2 forms of double counting that explain this difference, and which thus do not justify the volume of cutting required.

Further, we consider the 39,357 number also does not justify the volume of cutting needed once it achieves compliance because this volume likely includes a backlog of non-compliant spans. We discuss these issues in greater detail below.

United Energy double counted rectification cuts

United Energy separately forecast rectification cuts in its HBRA areas made in the fire danger period and outside of that period. This reflects the different timeframes it has to rectify non-compliant spans in those periods. We consider United Energy has double counted rectification cuts by doing this. All else equal, every rectification cut done prior to the start of the fire danger period avoids a cut that needs to be made in the fire danger period. This reflects the fact that the LiDAR inspections are completed prior to the start of the fire danger period.

United Energy's weekly status reports show the total count of non-compliant spans in United Energy's high bushfire risk areas over time.[38] VP1 spans are the highest priority with vegetation closest to the powerline. VP3 is the lowest priority with vegetation only just within the clearance space.

United Energy forecast the number of rectification cuts it needs to make in the fire danger period based on the maximum VP counts in 2024. However, this peak occurs outside the fire danger period and most, if not all, of these non-compliant spans were rectified prior to the start of the fire danger period. For example, United Energy was able to rectify all VP1 and VP2 spans before the end of the year in 2024. However, despite rectifying all its VP2 spans in 2024, United Energy is forecasting that it will need to do an additional 850 VP2 cuts in the bushfire danger period because its VP2 count peaked around 850 in 2024. Similarly, it forecast it will need to do an additional 1,400 VP3 cuts in the bushfire danger period. In this way we consider United Energy has over forecast the volume of rectification cuts it will need to do by 2,250 cuts. United Energy provided no reason to explain why the peak of its VP counts was a reasonable basis to forecast the additional number of rectification cuts required within the bushfire season.

United Energy double counted cuts in its base and uplift volumes

United Energy forecasts the volume of cuts it will need to do by forecasting a base volume plus an 'uplift'. As discussed above, it forecasts the uplift based on its cutting volumes for

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[38] United Energy, *Response to IR014 – vegetation management opex step change*, 24 April 2025

2024, when it completed 34,157 cuts. But to forecast the base volume it used its estimated volume for 2025, which is 35,635. This double counts 1,478 cuts.

These 2 forms of double counting explain the difference between the 39,357 total cuts required in 2024 and the 43,080 United Energy has forecast from 2027–28.

United Energy has assumed that the number of spans with vegetation inside the minimum clearance space will not improve from the high level of 2024

United Energy assumed that the number of non–compliant spans it will have in the 2026–31 period will not improve from what it was able to achieve in 2024. This is despite also forecasting an increase in the number of maintenance spans it will cut, which should reduce the number of non-compliant spans that need rectifying. United Energy has already significantly reduced the number of non-compliant spans it has identified in 2025. This can be seen in its weekly status reports where the number of non-compliant spans in HBRA areas has fallen significantly over the past 2 years, with some improvement in 2024 and further improvement in 2025. While we do not yet have a complete picture of 2025, it appears possible that United Energy will have no remaining non-compliant spans in its HBRA areas before the start of the next bushfire danger period.

The bushfire danger period is an important deadline in United Energy's management plan. Prior to the start of the bushfire danger period United Energy has 6 months, or until the start of the fire danger period, to rectify any non-compliance under its approved management plan. Once the fire danger period starts, it must rectify non-compliant spans within 2 days to 2 weeks, depending on how close the vegetation is to the powerline.[39]

Compliance is lagging in LBRA areas

We consider United Energy has already significantly improved its compliance in its HBRA areas, which it has prioritised. It is less advanced in its low bushfire risk areas (LBRA). In Figure 3.7, we show the number of cuts made and the remaining non-compliant spans in its LBRA areas. We can see that United Energy had more cuts remaining at the end of 2024. The darker shaded columns in the stacks represent the cuts made. The lighter shaded columns reflect the spans that remained uncut at the end of the year.

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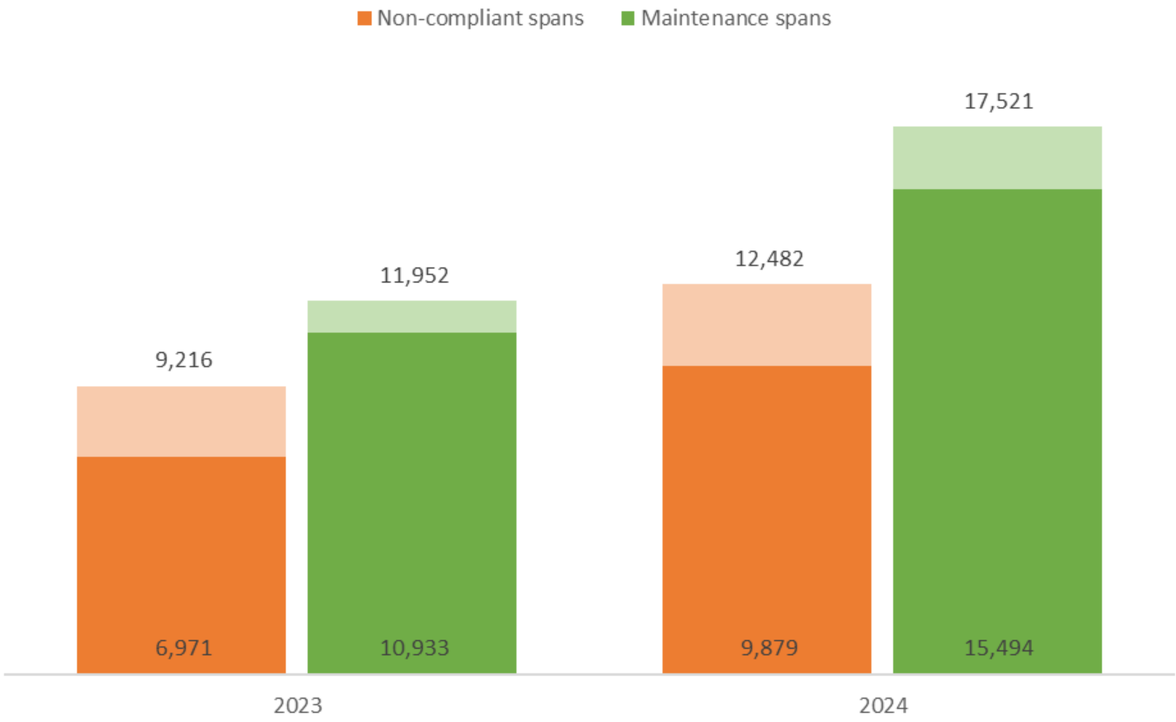
[39] United Energy, *UE ATT 9.05, CitiPower, Powercor and United Energy 2021–2026 Electric Line Clearance (Vegetation) Management Plan*, September 2022, pp. 26–27.

Figure 3.7 LBRA spans cut and remaining, 2023 to 2024



Source: United Energy, *Response to information request IR#014*, 22 April 2025; AER analysis.

United Energy forecast cut volumes for the 2026–31 period based on the 'total' cuts in 2024, the sum of cuts made and 'remaining' cuts. We were concerned that this may overestimate the number of cuts that will be required once compliance is achieved, since 2024 appears to include a backlog of non-compliant spans. To test this, we compared the ratio of rectification cuts to maintenance cuts in United Energy's LBRA areas compared to it HBRA areas. In its HBRA areas, United Energy's total rectification cuts (cut and remaining) were 43% of its total maintenance cuts (cut and remaining) in 2024. But in its LBRA areas, total rectification cuts (cut and remaining) were 71% of its total maintenance cuts (cut and remaining) in 2024. We would expect this to reduce once United Energy achieves compliance.

We also note that United Energy's total number of maintenance spans (cut and remaining) was significantly higher in 2024 than in 2023 in its LBRA areas. We reviewed the maintenance span volumes that United Energy reported in its category analysis RIN (in table 2.7.1) and note that the number of spans that United Energy reported for urban and CBD areas varies significantly from year to year. Given this, using the cut volumes (cut and remaining) from a single year may not reasonably reflect the volumes United Energy needs to cut each year going forward for its LBRA areas.

Hazard trees

United Energy included additional opex of $10.7 million to increase the frequency of hazard tree inspections from every 5 years to every 3 years. United Energy stated that its management plan specifies a 3-year cycle.[40] This 3-year cycle was included in the management plan United Energy submitted in June 2020.[41]

Within its model, United Energy calculates the uplift in its hazard tree program as the difference between a hard-coded value of $3 million and its hazard tree costs in 2022–23. It also accounts for increased real prices. It provides no explanation for the proposed increase other than to say that it estimates it will need to carry out approximately double the hazard tree inspections per year than it is currently carrying out.[42]

We are not satisfied that United Energy requires additional opex to inspect for hazard trees at the frequency set out in its management plan. We consider that there is sufficient opex in United Energy's base opex and the rate of change. Further, United Energy has not explained the basis for the proposed increase. The 2 times increase is more than would be required to undertake the same work in a 3-year period compared to a 5-year period (which would require 1.7 times increase in inspection costs).

We also note that United Energy appears to have increased its total cost for hazard tress, not just its inspection costs. United Energy gave no reason why increasing the frequency of hazard tree inspections would increase its hazard tree mitigation costs. Increasing the inspection frequency will not change the number of hazard trees, only the timing of when they are identified.

United Energy did not account for the impact of the rate of change on base year expenditure

United Energy calculated its proposed step change as the difference between its forecast of vegetation management costs in a given year and the amount it estimated for the base year (2024–25). In forecasting its vegetation management costs it accounted for forecast price growth. However, in calculating the step change it did not account for the application of the rate of change to base year opex. This, in effect, double counts the impact of the rate of change on United Energy's vegetation management base year opex.

United Energy's proposed step change may not share efficiency gains and losses symmetrically

Since 2010, the Electricity Safety (Electric Line Clearance) Regulations, and the underlying Code of Practice, have not changed significantly. In that time United Energy has not increased its opex to a level that United Energy considers it needs to comply with those obligations. Under the opex incentive framework, United Energy retains incremental efficiency gains (and losses) for 6 years. This means that if United Energy reduces its ongoing level of opex, its revenue (forecast opex and EBSS carryovers) doesn't reduce to the lower level until 6 years later. In this way United Energy benefited from not increasing its vegetation management opex for 6 years. If we provide a step change for United Energy to comply with its vegetation management obligations, it will not need to wait 6 years for its revenues to increase to the level it needs to comply with its regulatory obligations.

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40 United Energy, *UE ATT 9.02, Vegetation management step change*, p. 16.

41 United Energy, *UE ATT 9.04, 2020–2021 Electric Line Clearance (Vegetation) Management Plan*, June 2020, p. 25.

42 United Energy, *UE ATT 9.02, Vegetation management step change*, p. 16.

One of the opex factors we must have regard to when deciding whether forecast opex meets the opex criteria, is whether the opex forecast is consistent with any incentive scheme that applies. Consequently, we must have regard to the EBSS when considering forecast opex.

In implementing the EBSS, we must have regard to the desirability of both rewarding distributors for efficiency gains and penalising distributors for efficiency losses. Consistent with this, we consider that the opex incentive framework should operate in a symmetric way. That is, United Energy should be penalised for any additional costs it needs to incur to meet its regulatory obligations in the same way it has been rewarded for not increasing its opex to a level that would allow it to meet those obligations.

However, while the NER requires us to have regard to the EBSS, we must ensure the forecast opex is sufficient for United Energy to comply with all its regulatory obligations. We cannot reject a step change on the grounds it should be paid for by EBSS rewards. That said, both the *Expenditure forecast assessment guideline* and the EBSS allow for non-recurrent efficiency gains in the base year.

We are considering whether United Energy's non-compliance with its vegetation management obligations constitutes a non-recurrent efficiency gain. We would welcome stakeholders' views on this issue. If we were to consider the additional opex required to comply with vegetation management obligations was a non-recurrent efficiency gain, then the additional opex would be recognised in the EBSS. This would penalise United Energy for the additional opex it needs to incur to meet its regulatory obligations in the same way it has been rewarded for not increasing its opex to a level that would allow it to meet those obligations.

3.3.4.3 Consumer Energy Resource (CER) integration step changes

We have included $13.5 million for CER integration in our alternative estimate of total forecast opex for the draft decision. This is $5.5 million less than the amount proposed by United Energy, and reflects that we are not satisfied that the full proposed costs are prudent and efficient.

Table 3.11 United Energy's CER integration step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
United Energy's proposal	1.1	4.1	4.2	4.6	4.9	18.9
AER alternative estimate	0.9	2.8	2.9	3.3	3.5	13.5
Difference	**–0.3**	**–1.3**	**–1.3**	**–1.3**	**–1.3**	**–5.5**

Source United Energy, *UE MOD 1.05 – Opex*, January 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding.

United Energy proposed $18.9 million (1.9% of forecast total opex) for consumer energy resources (CER) integration to support its broad CER strategy, which it considered is required to meet the needs of an evolving network undergoing a fundamental energy transition.[43] United Energy submitted this change is driven by factors including a customer-led change to the interaction with energy services, such as CER, the government's net-zero commitment, growing renewable generation and battery deployment, and the anticipated electrification of transport and gas.[44] United Energy further submitted that although the CER and electrification investments will come at some cost to customers in the short-term, these will be materially outweighed by the resulting benefits in the long-term.[45] United Energy's CER integration step change broadly consists of 3 key programs:

1. Flexible services ($13.5 million) – investments to transition from static CER controls to flexible CER operation and management
2. Non-network procurement platform ($3.6 million) – development of a non-network marketplace
3. Network data visibility ($1.8 million) – development of a customer portal.

The above programs also relate to investments proposed in United Energy's capital expenditure proposal. We have jointly assessed this proposal, including through the information provided in the respective business cases and models for the 3 programs, the responses received to our information requests, and information obtained through an onsite workshop. We also engaged EMCa to provide technical advice on the prudency and efficiency of the proposed expenditure for both opex and capex.

We provide details on each of these programs, our assessment and the reasons for our decisions on United Energy's respective programs (both opex and capex), in **Attachment 2** of our draft decision for CitiPower. [46] We have provided details in CitiPower's attachment only, because the proposals are largely consistent across CitiPower, Powercor and United Energy. We have therefore completed a joint assessment both across opex and capex, and across all 3 businesses. [47] In summary, we have included costs as proposed for flexible services.

3.3.4.4 Cloud services and ICT modernisation step changes

We have included $32.8 million for the Cloud services and ICT modernisation & new capabilities step changes in our alternative estimate of total forecast opex for the draft decision. This is $23.2 million less than the amount proposed by United Energy, and reflects that we are not satisfied that the full proposed costs and programs are prudent and efficient.

We have combined these 2 step changes as they largely reflect the recurrent (ICT modernisation & new capabilities) and non-recurrent (Cloud services) costs of the respective programs within the 2 step changes.

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43 United Energy, *Regulatory Proposal 2026–31 – Part B – Explanatory Statement,* January 2025, pp. 14, 19–30; United Energy, *UE MOD 8.03 – Opex step changes,* January 2025.

44 United Energy, *Regulatory Proposal 2026–31 – Part B – Explanatory Statement, January 2025*, pp. 19–20.

45 United Energy*, Regulatory Proposal 2026–31 – Part B – Explanatory Statement,* January 2025, p. 14.

46 AER, *Attachment 2 – Capital expenditure – Draft decision –CitiPower distribution determination 2026–31*, September 2025.

47 AER, *Attachment 2 – Capital expenditure – Draft decision –CitiPower distribution determination2026–31*, September 2025.

Table 3.12 United Energy's Cloud services step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
United Energy's proposal	1.0	1.0	8.4	10.5	3.4	24.3
AER alternative estimate	0.8	0.4	0.6	1.3	0.8	3.9
Difference	**–0.2**	**–0.6**	**–7.8**	**–9.2**	**–2.6**	**–20.4**

Source United Energy, *UE MOD 1.05 – Opex*, January 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

Table 3.13 United Energy's ICT modernisation step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
United Energy's proposal	0.5	4.7	8.2	8.4	9.7	31.6
AER alternative estimate	1.9	4.8	6.9	7.0	8.3	28.9
Difference	**1.3**	**0.1**	**–1.4**	**–1.4**	**–1.4**	**–2.7**

Source United Energy, *UE MOD 1.05 – Opex*, January 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding.

United Energy proposed these step changes (5.6% of total forecast opex) for additional opex to support new ICT programs, and for the reclassification of cloud services from capex to opex, consistent with the change in accounting treatment. United Energy submitted these costs consist of the following programs:[48]

1. Cyber security ($18.8 million) – investment to maintain prudent cyber maturity and protection
2. Enterprise resourcing planning and billing systems ($23.2 million) – upgrade its current systems reaching end-of-life and to achieve convergence across the other businesses
3. Infrastructure refresh ($10.9 million) – transition to cloud-based services
4. Market interface technology enhancements (MITE) ($3.1 million) – AEMO compliance-driven reforms.

The above programs relate to investments proposed in United Energy's capital expenditure proposal. We have jointly assessed this proposal, including through the information provided in the respective business cases and models for the 4 programs, the responses received to our information requests, and information obtained through an onsite workshop. We also engaged EMCa to provide technical advice on the prudency and efficiency of the proposed expenditure for both opex and capex.

We provide details on each of these programs, our assessment and the reasons for our decisions on United Energy's respective programs (both opex and capex) in **Attachment 2** of our draft decision for CitiPower. We provided details in CitiPower's attachment only, because the proposals are largely consistent across CitiPower, Powercor and United Energy.

48 United Energy, *Regulatory Proposal 2026–31 – Part B – Explanatory Statement,* January 2025, p. 81; United Energy, *UE MOD 8.03 – Opex step changes*, January 2025.

We have therefore completed a joint assessment both across opex and capex, and across all 3 businesses. In summary, we have included costs, as proposed, for cyber security, infrastructure refresh and for MITE.

3.3.4.5 Network and community resilience

We have not included the $4.4 million network and community resilience step change in our alternative estimate. We consider United Energy's total base opex and the rate of change provide sufficient opex for United Energy to undertake these activities in the 2026–31 period.

Table 3.14 United Energy's Network and community resilience step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
United Energy proposal	0.8	0.9	0.9	0.9	0.9	4.4
AER alternative estimate	–	–	–	–	–	–
Difference	**–0.8**	**–0.9**	**–0.9**	**–0.9**	**–0.9**	**–4.4**

Source United Energy, *UE MOD 1.05 – Opex*, January 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

United Energy proposed the same network and community resilience programs as Powercor. Our detailed assessment and reasoning for not including this step change in our alternative estimate of total opex is the same for United Energy as for Powercor. Refer to **Attachment 3** of our Powercor draft decision for further detail, and **Attachment 2** of our Powercor draft decision for further detail on related capex programs.

3.3.4.6 Fleet electrification

United Energy proposed a negative step change of -$0.2 million (0.03% of forecast opex) related to fleet electrification. United Energy stated this was in response to an expected reduction in its vehicle operating costs due to its proposed electric vehicle transition program. Consistent with our capex position, which has accepted United Energy's fleet electrification program, we have included this step change in our alternative estimate, without adjustment. More detail can be found in **Attachment 2** of our draft decision.

Table 3.15 United Energy's fleet electrification step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
United Energy's proposal	–	–0.0	–0.0	–0.1	–0.1	–0.2
AER alternative estimate	–	–0.0	–0.0	–0.1	–0.1	–0.2
Difference	**–**	**–**	**–**	**–**	**–**	**–**

Source United Energy, *UE MOD 1.05 – Opex*, January 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

3.3.4.7 Insurance

We have included a negative step change of –$22.6 million (2.3% of forecast opex) to ensure the overestimated insurance premiums included in forecast opex for the current 2021–26 period do not impact forecast opex for the 2026–31 period.

Table 3.16 United Energy's insurance step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
United Energy's proposal	–	–	–	–	–	–
AER alternative estimate	–4.5	–4.5	–4.5	–4.5	–4.5	–22.6
Difference	**–4.5**	**–4.5**	**–4.5**	**–4.5**	**–4.5**	**–22.6**

Source United Energy, *UE MOD 1.05 – Opex*, January 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

Our final decision for the 2021–26 regulatory period included a $28.9 million ($2020–21) step change for forecast increases in insurance premiums in our alternative estimate. In that decision, we considered that the forecast increases qualified as a step change because they were driven by a major external factor outside of the control of the business and were not captured in base opex or trend.

Under our framework when we approve a step change, we assume the expenditure is required in perpetuity. Our standard approach to forecast total opex, applies a final year increment to roll forward any additional expenditure required from the final year approved forecast to base year approved forecast. This results in United Energy's proposed final year increment including the difference between the forecast insurance premiums (insurance step change) in the final year (2025–26) and base year (2024–25), which equates to $0.7 million or $3.3 million over the 2026–31 regulatory control period.

We asked United Energy to provide its actual insurance premiums in the current period. These showed that the forecast of significant insurance premiums did not eventuate, and it significantly underspent the forecast insurance premiums.[49]

Under the NER we must accept or not accept a network business's proposed opex forecast.[50] This choice depends on whether we consider the proposed forecast reasonably reflects the opex criteria. The criteria provide that the forecast must reasonably reflect the efficient costs that a prudent operator would require to meet expenditure objectives, given a realistic forecast of demand and cost inputs. In making this decision we must have regard to the opex factors.

One of the opex factors we must have regard to is whether an opex forecast is consistent with any incentive schemes that apply to a network.[51] The NER requires that we must

49 United Energy, *Response to information request IR#018*, 5 May 2025.

50 NER clause 6.5.6(c)–(d).

51 NER clause 6.5.6(e)(8).

develop and publish an EBSS that provides a fair sharing of efficiency gains and losses between network businesses and network users.[52]

Including the insurance premium component ($3.3 million) of the final year increment assumes insurance premiums would rise significantly more than required. We now know these increases will not occur and reflecting them in our alternative estimate of total forecast opex would not meet the opex criteria. That is, forecast opex would be materially higher than that required by a prudent operator.

We also consider, this would not provide a fair sharing of efficiency gains or losses under the EBSS and that the previously approved 2021–26 insurance step changes are not a recurrent step up in costs required in perpetuity (that is, we consider they are non-recurrent). Including this insurance component of the final year increment results in network users waiting 6 years before the previously forecast insurance premium increases are no longer reflected in allowed revenues.

To remove the insurance premium component of the final year increment, our alternative estimate for the draft decision includes a combination of a negative insurance step change and a non-recurrent efficiency gain. This ensures our alternative estimate of total forecast opex meets the opex criteria and the EBSS provides a fair sharing of efficiency gains and losses between network businesses and network users.

The negative step change, calculated as the difference between the final year premium allowance and actual premium, removes the expected over forecasting of insurance premiums in 2025–26, thus ensuring this over forecasting isn't continued into the 2026–31 period. It then sets the non-recurrent efficiency gain in the base year equal to the insurance underspend in the base year. Together, this results in:

- forecast opex equal to that required by a prudent operator.
- network businesses returning all the 2021–26 insurance premium underspends through EBSS decrements 6 years later (treating the underspends as non-recurrent efficiency gains). The NSP retains its share of the insurance premiums underspend as it retains the time value of holding the underspends for 6 years.

3.3.5 Category specific forecasts

United Energy's proposal included 3 category specific forecasts, which were not forecast using the base-step-trend approach. These were for:

- Innovation fund ($6.0 million)
- GSL payments ($9.2 million)
- debt raising costs ($8.0 million).

Additionally, as discussed in section 3.3.5.3, we have reclassified United Energy's customer assistance package step change ($8.7 million – our lower amount) as a category specific forecast in our alternative estimate.

52 NER clause 6.5.8(a).

3.3.5.1 Innovation Fund

We have included $1.7 million for the innovation fund in our alternative estimate of total forecast opex for the draft decision. This is $4.2 million less than the estimate proposed by United Energy, and reflects that we are not satisfied that the full proposed costs and programs are prudent and efficient.

Table 3.17 Innovation Fund ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
CitiPower proposal	1.5	1.5	1.0	1.0	1.0	6.0
AER alternative estimate	0.3	0.3	0.3	0.3	0.3	1.7
Difference	**–1.1**	**–1.1**	**–0.6**	**–0.6**	**–0.6**	**–4.2**

Source: United Energy, *UE MOD 1.05 – Opex*, January 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding.

United Energy proposed $6.0 million (0.6% of forecast total opex) for a network innovation fund, which the business submitted will ensure it continues to keep pace with changes underway in the energy market and to meet the expectations placed on network in this environment.[53] The business submitted that without explicit innovation funding, new approaches and the associated benefits are unlikely to be realised, particularly for customer focused innovation programs. It therefore considered its innovation allowance will deliver projects that will contribute long term customer value.[54] In total, United Energy's proposal included 12 individual projects, broadly grouped into 3 categories:

1. Assisting the energy transition
2. Improving customer experiences
3. Developing sustainable networks.

United Energy proposed to self-fund 10% of the total program, and to further exclude the innovation expenditure from the EBSS. However, United Energy also raised concerns with our requirements for forecasting innovation expenditure, including the requirement to specify all the proposed innovation projects, and to provide supporting cost-benefit analysis data for these projects.[55]

The above program also contains corresponding capital expenditure costs. We have jointly assessed the above programs with United Energy's capital expenditure proposal, including through the information provided in its initial proposal and through subsequent the responses received to our information requests.

We provide details on each of these programs, our assessment and the reasons for our decisions of United Energy's respective programs (both opex and capex), in **Attachment 2**

53 United Energy, *UE BUS 10.01 – Innovation allowance*, January 2025, p. 9.

54 United Energy, *UE BUS 10.01 – Innovation allowance*, January 2025, p. 12.

55 United Energy, *UE BUS 10.01 – Innovation allowance*, January 2025, pp. 10–12.

of our draft decision for CitiPower.[56] We provided details in CitiPower's attachment only, because the proposals are largely consistent across all 3 businesses (CitiPower, Powercor and United Energy). We have therefore completed a joint assessment both across opex and capex, and across all 3 businesses.

For our alternative estimate of total forecast opex for the draft decision, and for the reasons discussed in **Attachment 2**, we have included a lower amount of $1.7 million.

3.3.5.2 Guaranteed Service Level (GSL) payments

United Energy also included a category specific forecast for GSL payments of $9.2 million in its proposal. These are payments United Energy makes to customers who experience reliability less than the specified performance thresholds in the Electricity Distribution Code. We have made one adjustment to the forecast we have included in our alternative estimate. United Energy increased the GSL payments by 15% in the expectation that the Essential Services Commission (ESC) will update the GSL payment rates, which it typically does every 5 years. The ESC, however, has not updated the GSL scheme. We will update the GSL payment amounts in our final decision to reflect any amendments the ESC makes to the scheme prior the final decision.

We also note that the proposed forecast of GSL payments was calculated using an estimate of outages for 2024–25. We expect that United Energy will update the forecast in its revised proposal using actual outage data for 2024–25.

Table 3.18 GSL payments ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
United Energy proposal	2.0	1.9	1.8	1.8	1.7	9.2
AER alternative estimate	1.7	1.7	1.6	1.6	1.5	8.1
Difference	**–0.3**	**–0.2**	**–0.2**	**–0.2**	**–0.2**	**–1.2**

Source United Energy, *UE MOD 1.05 – Opex*, January 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding.

3.3.5.3 Customer assistance package

As discussed in section 3.3.4.1, we have reclassified United Energy's proposed customer assistance package step change ($14.7 million) as a category specific forecast for our lower alternative estimate of $8.7 million.

Table 3.19 Customer assistance package ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
United Energy proposal	-	-	-	-	-	-
AER alternative estimate	1.7	1.7	1.7	1.8	1.8	8.7

[56] AER, *Attachment 2 – Capital expenditure – Draft decision – CitiPower distribution determination 2026–31*, September 2025.

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Difference	1.7	1.7	1.7	1.8	1.8	8.7

Source United Energy, *UE MOD 1.05 - Opex*, January 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

3.3.5.4 Debt raising costs

We have included debt raising costs of $7.7 million in our alternative estimate. This is $0.2 million less than the amount proposed by United Energy.

Table 3.20 Debt raising costs ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
United Energy proposal	1.6	1.6	1.6	1.6	1.6	8.0
AER alternative estimate	1.6	1.6	1.5	1.5	1.5	7.7
Difference	**0.0**	**–0.0**	**–0.0**	**–0.1**	**–0.1**	**–0.2**

Source United Energy, *UE MOD 1.05 – Opex*, January 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding

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

Shortened forms

Term	Definition
AER	Australian Energy Regulator
CAP	Consumer Advisory Panel
capex	capital expenditure
CCP32	Consumer Challenge Panel, sub-panel 32
CER	Consumer energy resource
DNSP	distribution network service provider
distributor	distribution network service provider
EBSS	efficiency benefit sharing scheme
ESC	Essential Services Commission
FPAC	First Peoples Advisory Committee
Guideline	Expenditure Forecast Assessment Guideline for Electricity Distribution
GSL	guaranteed service levels
HBRA	High bushfire risk area
LBRA	Low bushfire risk areas
MTFP	Multilateral total factor productivity
MPFP	Multilateral partial factor productivity
NEM	national electricity market
NER or the rules	national electricity rules
NSP	network service provider
opex	operating expenditure
PPI	partial performance indicator
PTRM	post-tax revenue model
RBA	Reserve Bank of Australia
RIN	regulatory information notice
SCS	standard control services