FINAL DECISION

United Energy
Distribution Determination
2021 to 2026

Attachment 6
Operating expenditure

April 2021

AUSTRALIAN ENERGY REGULATOR

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Note

This attachment forms part of the AER's final decision on the distribution determination that will apply to United Energy for the 2021–26 regulatory control period. It should be read with all other parts of the final decision.

The final decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

Attachment 12 – Customer Service Incentive Scheme

Attachment 13 – Classification of services

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6 Operating expenditure

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

This attachment outlines our assessment of United Energy’s revised opex proposal for the 2021–26 regulatory control period.

6.1 Final decision

Our final decision is to accept United Energy's total opex forecast of $728.7 million ($2020–21), including debt raising costs, for the 2021–26 regulatory control period.[1] We have tested United Energy's updated revised proposal by comparing it to our alternative estimate of $722.8 million ($2020–21), which is generally consistent with United Energy's updated revised proposal ($5.9 million, or 0.8 per cent, lower). We therefore consider that United Energy's total opex forecast reasonably reflects the opex criteria.[2]

Our final decision opex forecast is:

- $60.9 million (or 7.7 per cent) lower than the opex forecast we approved in our final decision for the 2016–20 regulatory control period[3]
- $85.3 million (or 13.3 per cent) higher than United Energy's actual (and estimated) opex in the 2016–20 regulatory control period
- $69.1 million (or 8.7 per cent) lower than United Energy's initial proposal.

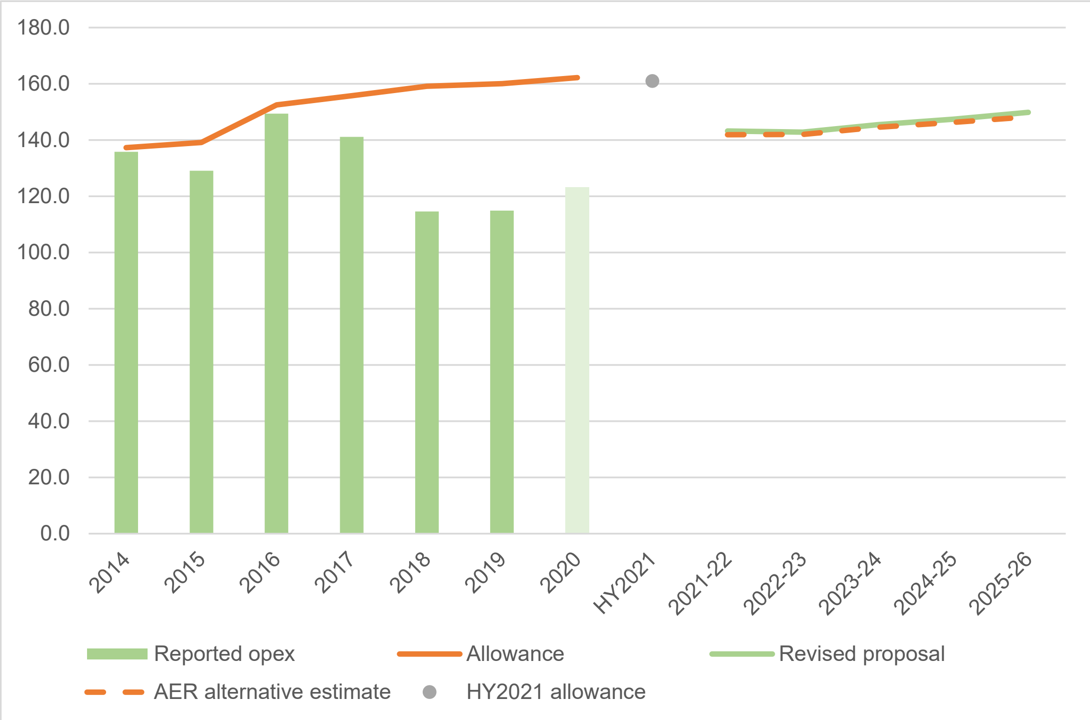
Figure 6.1 shows United Energy’s actual opex, our previous approved forecast opex, proposed opex for the next five years and our alternative estimate for the final decision.

[1] United Energy, *Revised Regulatory Proposal – 2021–26 – MOD 10.06 – Opex*, March 2021

[2] NER, cl.6.5.6(c).

[3] Difference is calculated based on the five year 2016–20 period (not including the HY2021 extension) using unlagged inflation.

Figure 6.1 United Energy's opex over time ($ million, 2020–21)



Source: United Energy, *Revised Regulatory Proposal – 2021–26 - MOD 10.06 - Opex*, December 2020 ; AER, *Final Decision, United Energy distribution determination 2021–26, Opex model*, April 2021; AER, *Final Decision, United Energy distribution determination 2021–26, EBSS model*, April 2021; AER analysis.

Table 6.1 sets out United Energy's revised proposal, its updated revised proposal (which we accept), and our alternative estimate.

Table 6.1 Comparison of United Energy's revised opex proposal and our alternative estimate ($ million, 2020–21)

	United Energy's revised proposal	Updated revised proposal	AER alternative estimate	Difference
Base (reported opex in 2019)	598.8	598.8	598.8	–
Base year adjustments	11.3	11.3	8.0	–3.3
Final year increment	17.9	17.9	21.1	3.2
Trend: Output growth	15.3	15.3	14.7	–0.6
Trend: Real price growth	8.2	8.2	8.1	–0.1
Trend: Productivity growth	–8.6	–8.6	–8.6	0.0
Step changes	58.2	75.3	70.3	–5.0
Net category specific forecasts	5.2	4.4	4.3	–0.0
Total opex (excluding debt raising costs)	**706.4**	**722.6**	**716.8**	**–5.8**

	United Energy's revised proposal	Updated revised proposal	AER alternative estimate	Difference
Debt raising costs	6.1	6.1	6.0	–0.0
Total opex (including debt raising costs)	**712.4**	**728.7**	**722.8**	**–5.9**
Percentage difference to updated revised proposal				–0.8%

Source: United Energy, *Revised Regulatory Proposal - 2021–26 - MOD 10.06 - Opex*, March 2021; AER, *Final Decision, United Energy distribution determination 2021–26, Opex model*, April 2021; AER analysis.

Note: Numbers may not add up to totals due to rounding. The difference is between United Energy's updated proposal and our final decision. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance. Net category specific forecasts captures the net impact of removing these costs from the base year and re-forecasting as a category specific forecast for the 2021–26 regulatory control period.

The following key factors explain the differences in our alternative estimate of total opex, compared to the updated revised proposal, which we have accepted:

- For base adjustments, our alternative estimate is $3.3 million ($2020–21) lower than United Energy's proposal as we have included a lower forecast for Advanced Metering Infrastructure (AMI) communications network.
- Our final year increment is $3.2 million ($2020–21) higher as we have updated for the latest inflation actuals and forecasts.
- Our rate of change is $0.7 million ($2020–21) lower than United Energy's proposal. For labour price growth, we have used more recent forecasts from Deloitte Access Economics. For output growth, we have updated output weights based on our 2020 Benchmarking Report.
- Opex related to step changes is $5.0 million ($2020–21) lower as we have not included demand management programs in our alternative estimate and made an efficiency adjustment to the proposed solar enablement expenditure.

We have included in our alternative estimate a step change for insurance premiums. This reflects our view, on balance, that while there is some uncertainty associated with the forecast insurance premium costs, businesses are best incentivised to achieve efficient cost outcomes for this by including them in the total opex forecast. Subsequently, United Energy provided an updated revised proposal including a step change for insurance premiums of $28.9 million ($2020–21), which we consider is reasonable and we have included this amount in our alternative estimate. As a result, we have not accepted the proposed insurance premiums nominated cost pass through event for the 2021–26 regulatory control period.

6.2 United Energy's revised proposal

United Energy used a 'base-step-trend' approach to forecast opex for the 2021–26 regulatory control period in its revised and updated revised regulatory proposals, consistent with our standard approach.

United Energy proposed a revised total opex forecast of $712.4 million ($2020–21) for the 2021–26 regulatory control period.[4] This included a step change for insurance premium increases known as a result of the latest insurance renewals ($11.8 million ($2020–21)) and a proposed cost pass through for future increases. As set out below, our incentive based framework to achieve efficient outcomes, we consider forecast insurance premium increases are best included in the total opex forecast. Reflecting on this, United Energy submitted an updated total opex forecast of $728.7 million ($2020–21).[5] This included a step change for future insurance premium increases of $28.9 million ($2020–21) and updates to its guaranteed service levels (GSL) forecast.[6]

In applying our base-step-trend approach to forecast opex for the 2021–26 regulatory control period, United Energy:[7]

- used opex in 2019 as the base to forecast ($598.8 million ($2020–21))
- adjusted the base year expenditure to include forecast for activities which are not fully reflected or it considered should be removed in the base year expenditure ($11.3 million ($2020–21))
- added the final year increment from the base year of 2019 ($17.9 million ($2020–21))
- applied a rate of change comprising of:
    - real price escalation ($8.2 million ($2020–21))
    - output growth ($15.3 million ($2020–21))
    - and productivity (–$8.6 million ($2020–21))
- added forecast step changes for the 2021–26 regulatory control period ($75.3 million ($2020–21))
- added category specific forecasts for the 2021–26 regulatory control period ($4.4 million ($2020–21))
- added forecast debt raising costs ($6.1 million ($2020–21)).

United Energy's updated revised total opex proposal is set out in Table 6.2.

4 United Energy, *Revised Regulatory Proposal - 2021–26 - MOD 10.06 - Opex*, December 2020.
5 United Energy, *Revised Regulatory Proposal - 2021–26 - MOD 10.06 - Opex*, March 2021.
6 United Energy, *Revised Regulatory Proposal – 2021–26 – MOD 10.06 – Opex*, March 2021.
7 United Energy, *Revised Regulatory Proposal – 2021–26 – MOD 10.06 – Opex*, March 2021.

Table 6.2 United Energy's proposed opex ($ million, 2020–21)

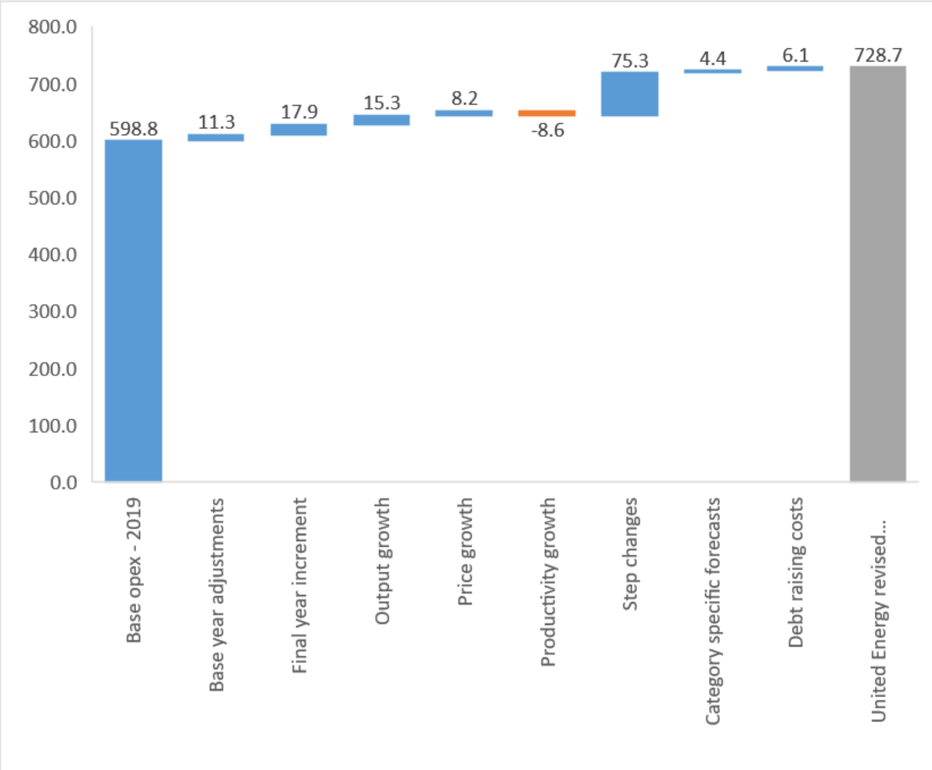
	2021–22	2022–23	2023–24	2024–25	2025–26	Total
Total opex excluding debt raising costs	142.0	141.6	144.2	146.2	148.6	722.6
Debt raising costs	1.2	1.2	1.2	1.2	1.2	6.1
Total opex	143.2	142.8	145.5	147.4	149.8	728.7

Source: United Energy, *Revised Regulatory Proposal – 2021–26 - MOD 10.06 - Opex*, March 2021.

Note: Numbers may not add up to totals due to rounding.

Figure 6.2 shows the different components in United Energy's opex proposal ($ million, 2020–21).

Figure 6.2 United Energy's revised opex forecast ($ million, 2020–21)



Source: AER analysis

6.2.1 Stakeholder views

We received four submissions on United Energy's 2021–26 proposal that raised issues about opex. At a high level, submissions were generally supportive of our draft decision noting concerns of productivity declines over time. Submissions provided commentary on various components of the revised proposals. We have taken these submissions, and any other concerns consumers identified, into account in developing the positions set out in this final decision. A summary of the opex issues raised in submissions is provided in Table 6.3.

Table 6.3 Submissions on United Energy's revised opex proposal

Stakeholder	Issue	Summary
AER Consumer Challenge Panel, sub panel 17 (CCP17), Ausgrid, Victorian Community Organisation (VCO), Energy Consumers Australia (ECA)	Base opex	The VCO suggested that a bottom-up sanity check may be useful in evaluating efficiency as all distributors except United Energy have experienced a decline in productivity over time. Further, that distribution businesses have consistently incurred lower opex costs than their allowance suggesting base opex is not efficient.[8] The CCP17 noted that based on the benchmarking results CitiPower, Powercor and United Energy are the most efficient distribution businesses in Australia for all measures, whereas AusNet Services and Jemena have performed poorly.[9] Consultant for ECA, Spencer&Co, expressed similar concerns about the benchmarking results. It considered the benchmarking results to be highly sensitive to inputs and that this presents risks when setting opex using these results.[10]
VCO	Trend	The VCO considered that to determine price growth the most recent data sources should be used (including the Victorian government's December 2020 estimates) and that the labour / materials weights should be the same across all businesses.[11] The VCO supported the AER's approach for developing output growth forecasts using updated information for the final decisions and to address the issues raised in the NERA and Frontier Economics reports.[12] It considered a detailed review of the forecast growth in outputs is required, including for customer numbers (connections), peak demand and energy throughput. It also sought consistency in approach across all businesses.[13] The VCO considered the 0.5% per annum productivity growth forecast is too low.[14]
CCP17, VCO	Step Changes	The VCO supported the application of materiality as grounds for examining step changes, in particular the proposed Australian Energy Market Operator (AEMO) fees and Energy Safe Victoria (ESV) levy. It was generally supportive of the AER's decisions on the step changes in the draft decision.[15] The CCP17 also supported the application of materiality as a guide for

8 Headberry Partners report to VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 15–16, 50–51.

9 CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, pp. 56–57.

10 Spencer&Co report to ECA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 9.

11 Headberry Partners report to VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 52.

12 Headberry Partners report to VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 52.

13 Headberry Partners report to VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 22.

14 Headberry Partners report to VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 52.

15 Headberry Partners report to VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 54.

Stakeholder	Issue	Summary
		determining if proposed step changes are prudent and efficient and discussed the issues raised by CitiPower, Powercor and United Energy in its revised proposal.[16]
VCO, ECA	ESV Levy	The VCO supported the AER's draft decision that the ESV levy cost should be absorbed by the distribution businesses.[17] Consultant for ECA, Spencer&Co, generally supported the distribution businesses position to include fees and charges levied by regulators in the price control mechanism. It considered these costs cannot be controlled and that it is appropriate to pass the costs on to customers via price controls.[18]
CCP17, VCO, ECA	Solar/Future Grid	The CCP17 supported CitiPower, Powercor and United Energy's solar enablement step change with the caveat that these resources should be largely managed through automated network monitoring over time.[19] The VCO submitted that while some of CitiPower, Powercor and United Energy's counters to the AER's decision to reject their solar step change have some merit, CitiPower, Powercor and United Energy have not demonstrated any net benefit to the consumer.[20] Consultant for ECA, Spencer&Co, supported the AER's positions for the distribution businesses and recommends the AER review the CitiPower, Powercor and United Energy step change to satisfy itself that the cheapest opportunities for capacity expansion and DER facilitation are not being overlooked.[21]
CCP17, ECA	Demand management	The CCP17 was supportive of United Energy's step change proposal to manage peak demand through demand response programs.[22] Consultant for ECA, Spencer&Co, agreed with the AER's decision to amend the forecast to take out the cost of demand management (DM) being initiated on behalf of AusNet Services transmission on the basis that the costs of DM should be borne by the proponent. They suggested the AER re-examine the two DM projects using United's Energy's updated forecasts to ensure that they are not required. They were supportive of United's Energy's commitment to DM.[23]
CCP17, VCO, EUAA, ECA	Insurance Premiums	The VCO supported analysis of the insurance step change and cost pass through proposals to ensure these costs are not double counted. It noted there is support for developing the most efficient bushfire insurance program, with

16 CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, pp. 57–59.

17 Headberry Partners report to VCO*, Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 55.

18 Spencer&Co report to ECA*, Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 18.

19 CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 111.

20 Headberry Partners report to VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, pp. 55.

21 Spencer&Co report to ECA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 13.

22 CCP17*, Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 122.

23 Spencer&Co report to ECA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 23.

Stakeholder	Issue	Summary
		consumers sharing in the increased costs and risks, including general insurance which has not been impacted by the increased bushfire risk.[24] The CCP17 acknowledged that insurance coverage is decreasing while insurance costs are rising rapidly. It viewed the insurance market changes as material and beyond reasonable budget projections (with these changes likely to be sustained over a long period due to climate change). As such, it considered the insurance step changes to be reasonable.[25] Consultant for ECA, Spencer&Co, supported the steps taken by businesses to mitigate the cost impacts of rising insurance premiums on customers. They also considered that the businesses response to insurance premium increases is reasonable in the circumstances.[26]
CCP17, ECA	GSL	The CCP17 contended allowing businesses to recover GSL costs does not incentivise improved services. It believed businesses should bear the costs for GSL payment categories they have control over (e.g. for late or missed appointments or delays to connections) and 30 per cent of the other payment categories. The CCP17 proposed that the AER actively review the extent to which GSL payments should be met by the business rather than passed to customers.[27]
ECA	Metering	Consultant for the ECA, Spencer&Co, was supportive of a reallocation of metering costs where there is no metering competition, as it will make little difference to consumers.[28]

6.3 Assessment approach

Our role is to form a view about whether to accept a business' forecast of total opex. Specifically, we must form a view about whether a business' forecast of total opex 'reasonably reflects the opex criteria'.[29] In doing so, we must have regard to each of the opex factors specified in the National Electricity Rules (NER).[30]

If we are satisfied the business' forecast reasonably reflects the opex criteria, we must accept the proposed forecast.[31] If we are not satisfied, we must not accept the proposed forecast and must substitute an alternative estimate that we are satisfied reasonably reflects the opex criteria.[32] In making this decision, we take into account the reasons for the difference between our alternative estimate and the business'

24 Headberry Partners report to VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 56.

25 CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, pp. 61–63.

26 Spencer&Co report to ECA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 15.

27 CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, pp. 64–67.

28 Spencer&Co report to ECA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 18.

29 NER, cl. 6.5.6(c).

30 NER, cl. 6.5.6(e).

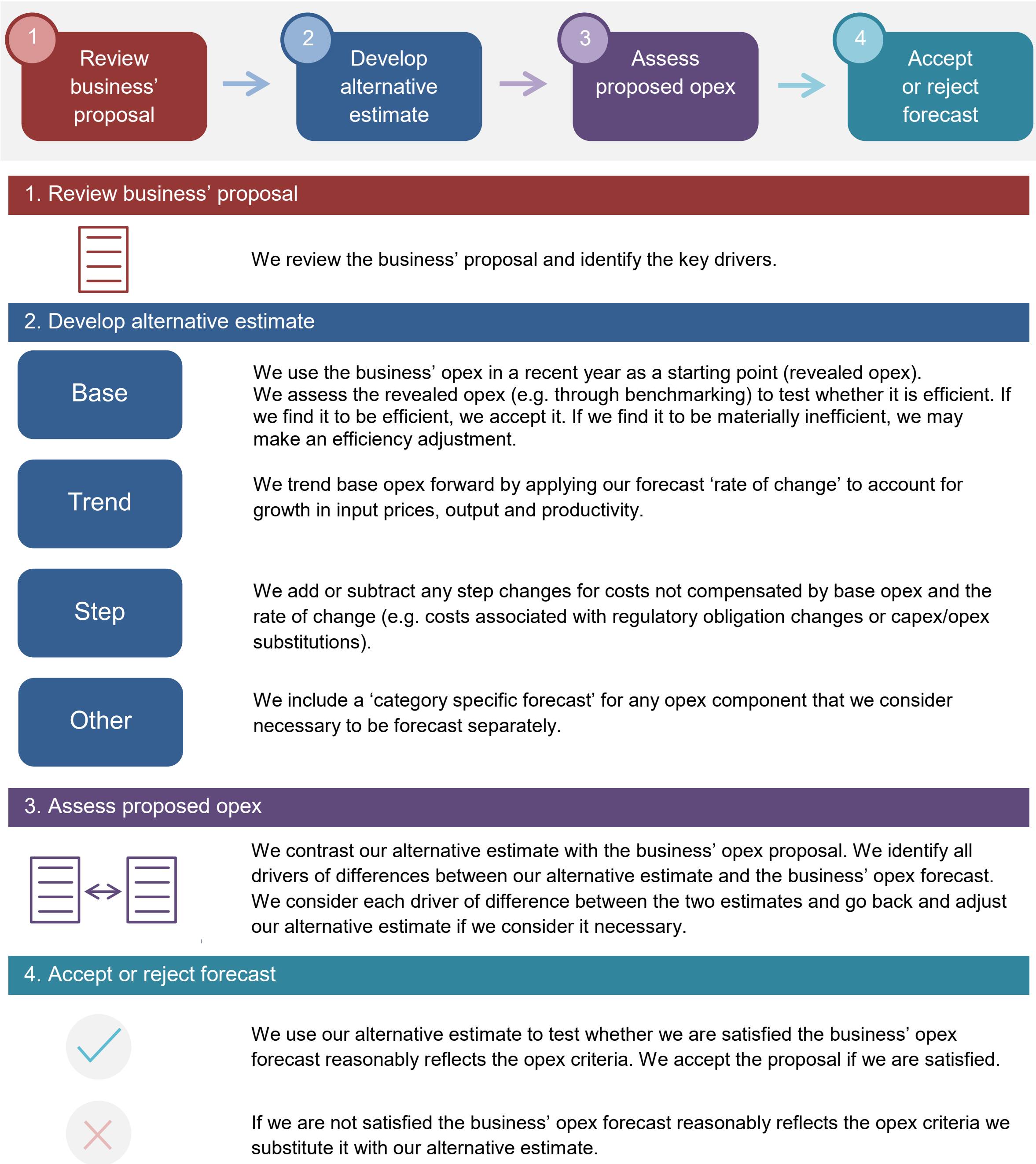
31 NER, cl. 6.5.6(c).

32 NER, cll. 6.5.6(d) and 6.12.1(4)(ii).

proposal, and the materiality of the difference. Further, we are required to consider interrelationships with the other building block components of our decision.[33]

As set out in our draft decision in detail, we generally assess a business' forecast total opex using a 'base-step-trend' approach, as summarised in Figure 6.3.[34]

Figure 6.3 Our opex assessment approach



[33] NEL, s. 16(1)(c).

[34] Our base–step–trend approach is also set out in our expenditure guideline. See AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, pp. 22–24.

6.3.1 Interrelationships

In assessing United Energy's total forecast opex we took into account other components of its proposal and our determination, including:

- the efficiency benefit sharing scheme (EBSS) carryover—the level of opex used as the starting point to forecast opex (the final year of the current regulatory control period (2016–20) should be the same as the level of opex used to forecast the EBSS carryover. This consistency ensures that the business is rewarded (or penalised) for any efficiency gains (or losses) it makes in the final year the same as it would for gains or losses made in other years
- the operation of the EBSS in the 2016–20 regulatory control period, which provided United Energy an incentive to reduce opex in the base year
- the impact of cost drivers that affect both forecast opex and forecast capital expenditure (capex). For instance, forecast labour price growth affects forecast capex and our forecast price growth used to estimate the rate of change in opex
- the approach to assessing the rate of return, to ensure there is consistency between our determination of debt raising costs and the rate of return building block
- concerns of electricity consumers identified in the course of United Energy's engagement with consumers.

6.4 Reasons for final decision

Our final decision is to accept United Energy's total forecast opex of $728.7 million ($2020–21),[35] including debt raising costs, in United Energy's revenue for the 2021–26 regulatory control period. We have tested United Energy's revised proposal by comparing it to our alternative estimate of the total opex forecast of $722.8 million ($2020–21),[36] which is not materially different from ($5.9 million ($2020–21), 0.8 per cent lower than) United Energy's revised proposal. Therefore, we are satisfied that United Energy's proposed forecast reasonably reflects the opex criteria.[37]

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

6.4.1 Base opex

This section provides our view on the prudent and efficient level of base opex that United Energy would need for the safe and reliable provision of electricity services over the 2021–26 regulatory control period.

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35 United Energy, *Revised Regulatory Proposal 2021–26 – MOD 10.06 – Opex*, March 2021

36 Including debt raising costs.

37 NER, cl.6.5.6(c).

For our final decision we have used base opex of $119.8 million ($2020–21) for each year of the 2021–26 regulatory control period or $598.8 million ($2020–21) over five years to form our alternative estimate.

6.4.1.1 Base year

Consistent with its initial proposal, and our draft decision, United Energy's revised proposal used 2019 as the base year for opex.[38]

Our position has not changed since the draft decision and we consider 2019 is an appropriate base year as it is representative of the base opex required for the next regulatory control period. We also note that, due to the interaction with the EBSS, we are generally indifferent to the choice of base year of a distributor provided we find its opex efficient.

6.4.1.2 Efficiency of base opex

As outlined in section 6.3, and in our Expenditure Forecast Assessment Guideline, our standard approach for forecasting opex is to use a revealed cost approach.[39] 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.

Analysis of United Energy's revealed costs, as shown in Figure 6.1, show a relatively stable trend in United Energy's opex over current regulatory control period, and opex has been below our approved forecast for this period.

However, we do not rely on the a priori assumption that the business' revealed opex is efficient. We use our top-down benchmarking tools, and other assessment techniques, to test whether the business is operating efficiently.

As set out in more detail in our draft decision, 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 and opex multilateral partial factor productivity (MPFP) 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.[40] Reflecting our conservative approach, we use a 0.75 comparator point (rather than 1.0) to assess the relative efficiency of distribution businesses.

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38 United Energy, *Revised regulatory proposal 2021–26*, December 2020, p. 113.

39 AER, *Expenditure forecast assessment guideline,* November 2013.

40 AER, *Draft Decision, United Energy distribution determination 2021–26, Attachment 6 Operating expenditure,* September 2020, p. 23.

In our draft decision, we observed that our benchmarking results showed that United Energy has performed relatively well amongst distributors in the National Energy Market (NEM) over the last fourteen years.[41] Our recent *2020 Annual Benchmarking Report*, published after the draft decision, shows United Energy continues to perform well, relative to other distribution businesses in the NEM.[42] In particular, United Energy remains a benchmark comparator business, with an average model score across the 2006–19 period of 0.752 and the 2012–19 period of 0.78, which are above our benchmark comparison point of 0.75. We also observe that United Energy:

- is fourth in terms of 2006–19 period-average multilateral total factor productivity (MTFP) which measures the relationship between total output and total input (i.e. capital assets and opex)[43]
- is fifth in terms of opex efficiency when measured using our econometric models and opex MPFP[44] over the periods 2006–19 and 2012–19[45]
- performed well for various total cost and opex cost category partial performance indicators (PPIs) over the four year period 2015–19.[46]

We consider that these results warrant the use of revealed costs in 2019 as the base year in our alternative estimate, as it provides an efficient base from which to form the 2021–26 regulatory control period opex allowance.

As set out in detail in the Jemena final decision, we recognise the potential impact that varying capitalisation practices (the use and/or reporting of opex versus capital) among the businesses may be having on the above opex benchmarking scores.[47] For the purposes of the Jemena final decision, we were informed by businesses' opex/capital ratios as indicators of capitalisation practices. We note that United Energy's opex/capital ratios are above the comparator average, indicating its opex benchmarking scores are not advantaged by its capitalisation practices.

The base year opex we use in our alternative estimate is $119.8 million ($2020–21). This figure has been updated from the draft decision to reflect updated inflation forecast in the Reserve Bank of Australia’s February 2021 *Statement on monetary policy*[48] for the year ending June 2021.

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41 AER, *Draft Decision, United Energy distribution determination 2021–26, Attachment 6 Operating expenditure*, September 2020, pp. 23–24.

42 AER, *Annual Benchmarking Report, Electricity distribution network service providers,* November 2020, pp. 21–22.

43 AER, *Annual Benchmarking Report, Electricity distribution network service providers,* November 2020, p. 21.

44 MPFP examines the productivity of opex and capital inputs in isolation. Opex MPFP considers the productivity of the distributor's operating expenditure.

45 AER, *Annual Benchmarking Report, Electricity distribution network service providers,* November 2020. pp. 32–33.

46 AER, *Annual Benchmarking Report, Electricity distribution network service providers,* November 2020. pp. 34–43.

47 See AER, *Final Decision, Jemena 2021–26, Attachment 6 Operating expenditure*, April 2021, pp. 33–38.

48 Reserve Bank of Australia, *Statement on monetary policy*, February 2021.

6.4.1.3 Final year increment

Our standard practice to estimate final year opex is to add the difference between the opex forecast for the final year of the preceding regulatory control period and the opex forecast for the base year to the amount of actual opex in the base year.[49] As a result of the six month extension to the current regulatory control period, we have updated our final year increment calculation in our alternative estimate by exchanging the opex forecast for the final year of the preceding regulatory control period to the annualised half year 2021 forecast.

6.4.1.4 Base adjustments

Advanced metering infrastructure (AMI) communications network

Consistent with our draft decision, our alternative estimate includes a base adjustment of $1.4 million ($2020–21) for the reclassification of AMI communications network costs.[50]

Table 6.4 United Energy's Reclassification of AMI Communication costs ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
United Energy’s revised proposal	0.9	0.9	0.9	0.9	0.9	4.6
AER final decision	0.3	0.3	0.3	0.3	0.3	1.4
Difference	–0.7	–0.7	–0.7	–0.7	–0.7	–3.3

Source: United Energy, *Revised Regulatory Proposal 2021–26 – MOD 10.06 – Opex*, March 2021; AER analysis.

Note: Numbers may not add due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

In our draft decision, we did not consider the meter power quality data volumes proposed by United Energy to allocate AMI communications network costs between standard control services (SCS) and alternative control services (ACS) were justified.[51] United Energy proposed an allocation of 88.0 per cent for SCS and 12.0 per cent for ACS based of the proportion of AMI meter data collected for SCS purposes relative to ACS purposes. Our draft decision alternative estimate included an estimate of AMI communications network costs based on an allocation of 25.0 per cent for SCS and 75.0 per cent for ACS.

49 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution,* November 2013. pp. 22–23.

50 AER*, Draft decision, United Energy distribution determination 2021–26, Attachment 6 Operating expenditure,* September 2020*,* p. 28.

51 AER, *Draft decision, United Energy distribution determination 2021–26, Attachment 6 Operating expenditure, September 2020 p.28.* AER*, Draft Decision, United Energy distribution determination 2021–26, Attachment 16 Alternative Control Services,* September 2020, pp. 32–36, 40–42.

United Energy’s revised proposal reproposed allocating 88.0 per cent of their AMI communications network costs from ACS to SCS, based on the findings of an independent review conducted by Operational Technology Solutions.[52] The review assessed which network management activities require AMI meter data and the frequency and population size of AMI meter data required to deliver these activities.

Based on our assessment of the information provided by United Energy, we do not consider that the AMI meter power quality data volumes proposed by United Energy for network management activities are required. For our alternative estimate, we have maintained our draft decision position to allocate AMI communications network costs based on an allocation of 25.0 per cent for SCS and 75.0 per cent for ACS. Further details, including the reasons for our maintaining our approach, are set out in Attachment 16 – Alternative control services.

Wasted truck visits

Consistent with our draft decision, our final decision is to include a base adjustment of $1.1 million ($2020–21) in our alternative estimate for the reclassification of wasted truck visits.[53]

Table 6.5 United Energy’s Wasted Truck Visits ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
United Energy revised proposal	0.2	0.2	0.2	0.2	0.2	1.1
AER final decision	0.2	0.2	0.2	0.2	0.2	1.1
Difference	–	–	–	–	–	–

Source: United Energy, *Revised Regulatory Proposal 2021–26 – MOD 10.06 – Opex*, March 2021; AER analysis.

Note: Numbers may not add due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

In our draft decision, we were satisfied that the proposed reclassification of wasted truck visits for network faults that turn out to be due to faults on the customer's side of the meter was consistent with our Framework and Approach paper.[54] We also considered the costs proposed by United Energy were reasonable as they were based on historical actual costs incurred.[55]

52 United Energy, *Revised Proposal 2021–26 – Supporting document ATT37 – OTS AMI data for network management*, December 2020.

53 AER, *Draft decision*, *United Energy distribution determination 2021–26, Attachment 6 Operating expenditure,* September 2020 pp. 27–28.

54 AER, *Final Framework and Approach for AusNet Services, CitiPower, Jemena, Powercor and United Energy*, January 2019, p. 32.

55 AER, *Draft Decision*, *United Energy distribution determination 2021–26, Attachment 6 Operating expenditure*, September 2020, pp. 27–28.

United Energy's revised proposal accepted our draft decision.[56] We have included this base adjustment in our alternative estimate, updating the costs to account for updated inflation forecasts.[57]

Repair works

Consistent with our draft decision, our final decision is to include a base adjustment of $17.5 million ($2020–21) in our alternative estimate for the reclassification of minor repairs.[58]

Table 6.6 United Energy's reclassification of minor repairs ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
United Energy revised proposal	3.5	3.5	3.5	3.5	3.5	17.5
AER final decision	3.5	3.5	3.5	3.5	3.5	17.5
Difference	–	–	–	–	–	–

Source: United Energy, *2021–26 Revised Regulatory Proposal– MOD 10.06 – Opex*, March 2021; AER analysis.

Note: Numbers may not add due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

In our draft decision, we were satisfied that it was appropriate for most of the types of minor repairs proposed by United Energy to be reclassified as opex.[59] Our consultant, EMCa, independently assessed the proposal and excluded the reclassification of work types which were considered not to be opex.

United Energy's revised proposal accepted our draft decision.[60] We have included this base adjustment in our alternative estimate, updating the costs to account for updated inflation forecasts.

ESV levies

Our final decision is to remove ESV levies from base opex in our alternative estimate as they will be recovered via the price control mechanism over the 2021–26 regulatory control period, following our decision on 19 March 2021 to approve the ESV levy as a

56 United Energy, *Revised regulatory proposal 2021–26,* December 2020, p. 118.

57 Reserve Bank of Australia, *Statement on monetary policy,* February 2021.

58 AER, *Draft decision*, *United Energy distribution determination 2021–26, Attachment 6 Operating expenditure*, September 2020 p.25–27.

59 AER, *Draft decision*, *United Energy distribution determination 2021–26, Attachment 6 Operating expenditure*, September 2020 p.25–27.

60 United Energy, *Revised regulatory proposal 2021–26,* December 2020, p. 118.

jurisdictional scheme.[61] This is consistent with United Energy's updated revised proposal, which removed ESV levy costs from base opex.[62]

Table 6.7 ESV levy ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
United Energy's revised proposal	–2.4	–2.4	–2.4	–2.4	–2.4	–11.9
AER final decision	–2.4	–2.4	–2.4	–2.4	–2.4	–11.9
Difference	–	–	–	–	–	–

Source: United Energy, *Revised Regulatory proposal 2021–26 – MOD 10.06 – Opex*, March 2021; AER analysis.

Note: Numbers may not add due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

United Energy's initial proposal sought a step change for expected increases in ESV levies over the 2021–26 regulatory control. Our draft decision did not include this proposed step change in our alternative estimate for the following reasons:[63]

- base opex already reflects the cost of meeting existing regulatory obligations, including the obligation to pay the ESV levy
- changes in specific costs should be managed within:
  - the existing base as the cost of other projects or programs decline. A rise in a single cost category is not sufficient to justify a step change, and/or
  - the rate of change forecast which escalates base opex to capture real increases in input prices and output growth (net of productivity growth).

In its revised proposal, United Energy proposed to recover the ESV levies through the price control mechanism as it is a cost that is unavoidable, outside of its control and not captured by the rate of change.[64]

The VCO's submission was supportive of our draft decision and considered the ESV levy increases should be absorbed by the distributors.[65] However, ECA's consultant, Spencer&Co, supported moving the ESV levy into the price control mechanism, on the basis that these fees are outside the control of the business.[66]

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61 AER, *Determination on CPU jurisdictional scheme request*, March 2021.

62 United Energy, *Revised Regulatory Proposal 2021–26 – APP08 – L–factor additions,* December 2020, p. 6.

63 AER, *Draft Decision, United Energy distribution determination 2021–26, Attachment 6 Operating expenditure,* September 2020, pp. 56–57.

64 United Energy, *Revised Regulatory Proposal 2021–26 – APP08 – L–factor additions,* December 2020, pp. 6–9.

65 Headberry Partners report to VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26 Submission to Initial Proposals,* January 2021, p. 55.

66 Spencer&Co report to ECA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 18.

On 25 February 2021, CitiPower, Powercor and United Energy submitted an application to request that the AER determine the ESV levy is a jurisdictional scheme.[67] We considered that the ESV levy meets the jurisdictional scheme criteria, and we determined that the ESV levy is a jurisdictional scheme.[68] Further details are in our decision.[69] In this distribution determination, we have also made a decision on how United Energy and the other Victorian businesses are to report to the AER on its recovery of the jurisdictional scheme amounts for the scheme and on the adjustments to be made to pricing proposals to account for over and under recovery.[70] As a result, the ESV levy becomes an approved jurisdictional scheme for United Energy. The scheme amounts are recovered via the price control mechanism and therefore we have removed such costs from total opex in our alternative estimate.

We note that while the ESV levy meets the jurisdictional scheme criteria, we consider from a policy perspective there is a strong case for such costs to remain in base opex. The reasons for this are:

- While there are costs which may be outside the control of the business, neither opex nor the EBSS within our framework distinguishes between controllable and uncontrollable costs. As stated in our explanatory statement for the EBSS to do so would weaken the incentive framework and there is no compelling reason to share the cost of uncontrollable events between consumers and the distributor differently to all other costs faced by the businesses. [71] Uncontrollable costs present both upside and downside risks to businesses, with any material risks able to be managed via pass-through events and contingent projects. So while levies and licence fee costs may be largely out of the control of businesses, this should not preclude them from being included in our total opex forecast and subject to the EBSS.
- While we recognise that licence fees and levy costs may be volatile, our top down approach looks at total opex. As explained in our assessment approach in the draft decision 'even if disaggregated opex categories have high volatility, the total opex varies to a lesser extent because new or increasing components of opex are generally offset by decreasing costs or discontinued opex projects.[72] Further, we expect the regulated business to manage the inevitable 'ups and downs' in the components of opex from year to year—to the extent they do not offset each other—by continually re-prioritising its work program, as would be expected in a workably competitive market. Our incentive-based, revealed cost, framework incentivises them to do so.'

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67 CitiPower. Powercor and United Energy, *Jurisdictional scheme determination request,* February 2021.

68 NER, cll. 6.18.7A(n) and 6.18.7A(x).

69 AER*, Determination on CPU jurisdictional scheme request*, March 2021.

70 NER, cl, 6.12.1(20) and AER, *Final decision, United Energy distribution determination 2021–26, Overview*, April 2021, Appendix A; AER, *Final decision*, *United Energy distribution determination 2021–26, Attachment 14 Control mechanisms,* April 2021, Appendix D.

71 AER, *Explanatory statement – efficiency benefit sharing scheme, November 2013*, pp. 19–21.

72 AER, *Draft Decision, United Energy distribution determination 2021–26, Attachment 6 Operating expenditure,* September 2020, p. 16.

- Increasing the number of items included in the price control mechanism makes it difficult for consumers to know how much tariffs will change year to year if they are subject to numerous adjustments.

United Energy's revised proposal also sought to recover changes in expected Australian Energy Market Operator (AEMO) fees through the price control mechanism for similar reasons it outlined in its revised proposal for ESV levies.[73]

On 26 March 2021, AEMO published its final report on Electricity Fee Structure which determined that distribution network service providers will not be charged participant fees for the next fee period.[74] As a result of AEMO's final report there is no need to include these fees in the price control formula.

6.4.2 Rate of change

Having determined an efficient starting point, or base opex, we trend it forward to account for the forecast growth in prices, output and productivity. We refer to this as the rate of change.[75]

In its revised proposal United Energy applied our standard approach to forecasting the rate of change. Specifically it:

- **output growth:** adopted the output weights, measures and vales we used in our draft decision.[76]
- **price growth:** adopted our input price weightings of 59.2 per cent labour and 40.8 per cent non-labour and an average of Wage Price Index (WPI) price growth forecasts from Deloitte and BIS Oxford Economics for labour price growth.[77]
- **productivity growth:** adopted our productivity growth forecast of 0.5 per cent per year.[78]

The rate of change proposed by United Energy contributes $14.9 million ($2020–21), or 2.0 per cent, to United Energy’s revised proposal total opex forecast of $728.7 million ($2020–21). This equates to opex increasing on average by around 0.9 per cent each year in the next regulatory control period.[79]

We have included a rate of change that on average increases opex by around 0.8 per cent each year in our alternative estimate. We have set out in Table 6.8

[73] United Energy, *Revised regulatory proposal 2021–26 – APP08 – L–factor additions*, December 2020, pp. 6–9.

[74] AEMO, *Final Report and Determination, Electricity Fee Structures,* March 2021, pp. 5, 26.

[75] AER, *Expenditure forecast assessment guideline*, November 2013, pp. 23–24.

[76] United Energy, *Revised regulatory proposal 2021–26* December 2020, pp. 119–120.

[77] United Energy, *Revised regulatory proposal 2021–26* , December 2020, pp. 119–120; United Energy, *Revised regulatory proposal 2021–26 – MOD 10.06 – Opex*, March 2021.

[78] United Energy, *Revised regulatory proposal 2021–26,* December 2020, pp. 119–120.

[79] United Energy, *Revised regulatory proposal 2021–26,* December 2020, pp. 119–120.

United Energy's updated revised proposal and our alternative estimates of each component of the rate of change. We have set out the reasons for our forecast below.

We received one submission, from the VCO, relating to the rate of change. It generally supported our approach to forecast the rate of change in our draft decision, specifically how we accounted for the impact of COVID-19. The VCO stated that we should apply the same approach across all the Victorian businesses.[80] We have considered this submission in making our final decision.

Table 6.8 Forecast rate of change, per cent

	2021–22*	2022–23	2023–24	2024–25	2025–26
United Energy's revised proposal					
Price growth	0.5	0.3	0.4	0.6	0.8
Output growth	0.5	0.9	1.0	1.0	1.0
Productivity growth	0.4	0.5	0.5	0.5	0.5
Overall rate of change	0.6	0.6	0.9	1.1	1.2
AER final decision					
Price growth	0.5	0.4	0.4	0.4	0.6
Output growth	0.5	0.8	1.0	1.0	0.9
Productivity growth	0.4	0.5	0.5	0.5	0.5
Overall rate of change	**0.6**	**0.7**	**0.8**	**0.9**	**1.0**
Overall difference	**–0.0**	**0.1**	**–0.1**	**–0.2**	**–0.2**

* The rate of change for 2021–22 reflects nine months' worth of growth in price, output and productivity to account for the extension of the current regulatory control period (2016–20) by six months to transition the timing of the regulatory control period for Victorian electricity distribution networks from a calendar year basis to a financial year basis. We discuss the reasons for this in our draft decision.

Source: United Energy, *Revised regulatory proposal 2021–26 – MOD 10.06 – Opex*, March 2021; AER analysis.

Note: Numbers may not add up to total due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

6.4.2.1 Forecast price growth

We have included forecast average annual real price growth of 0.4 per cent in our alternative opex estimate. This compares to United Energy's proposed average annual price growth of 0.5 per cent.[81] This increases our alternative estimate of total opex by

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80 Headberry Partners report to VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26 Submission to Initial Proposals*, January 2021, pp. 52.

81 United Energy, *Revised regulatory proposal 2021–26,* December 2020, p. 120.

$8.1 million ($2020–21), instead of $8.2 million ($2020–21) as proposed by United Energy.[82]

Our real price growth forecast is a weighted average of forecast labour price growth and non-labour price growth:

- To forecast labour price growth we use the forecast of growth in the WPI for the Victorian electricity, gas, water and waste services (utilities) industry. Specifically, we have used an average of forecasts from our consultant Deloitte and the BIS Oxford forecasts submitted by United Energy. In our draft decision we did not use the BIS Oxford forecasts submitted by United Energy with its regulatory proposal because we considered they did not account for the COVID–19 pandemic or the legislated changes to the superannuation guarantee.[83] The revised BIS Oxford forecasts submitted by United Energy now account for both of these issues.[84]
- Both we and United Energy applied a forecast non-labour real price growth rate of zero. This is consistent with our draft decision and United Energy's initial and revised proposals.[85]
- We applied benchmark input price weights of 59.2 per cent and 40.8 per cent for labour and non-labour, respectively. These are the weights we use for our econometric modelling in our annual benchmarking report.[86] This is consistent with our draft decision and United Energy's revised proposals.[87]

Consequently, we and United Energy have applied the same approach to forecast price growth. The only differences between our real price growth forecasts and United Energy's is that we have:

- used more recent forecasts of WPI growth from Deloitte[88]
- adjusted BIS Oxford Economics' WPI growth forecast for 2021–22 to reflect the growth between the average WPI value for the first six months of calendar year 2021 and the average value for the 2021–22 financial year. This is to account for the shift from calendar years to financial years and is the same approach we adopted for the draft decision.[89]

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82 United Energy, *Revised regulatory proposal 2021–26 – MOD 10.06 – Opex*, March 2021.

83 AER, *Draft decision, United Energy distribution determination 2021–26, Attachment 6, Operating expenditure*, September 2020, pp. 30–35.

84 United Energy, *Revised regulatory proposal 2021–26,* December 2020, p. 119.

85 AER, *Draft decision, United Energy distribution determination 2021–26, Attachment 6, Operating expenditure*, September 2020, p. 30; United Energy, *Regulatory proposal 2021–26*, January 2020, p. 154; United Energy, *Revised regulatory proposal 2021–26 – MOD 10.06 – Opex*, March 2021.

86 Economic Insights, *Memorandum prepared for the AER on review of reports submitted by CitiPower, Powercor and United Energy on opex input price and output weights,* 18 May 2020, p. 8.

87 AER, *Draft decision, United Energy distribution determination 2021–26, Attachment 6, Operating expenditure*, September 2020, pp. 29, 35–47; United Energy, *Revised regulatory proposal 2021–26 MOD 10.06, Opex*, March 2021.

88 Deloitte Access Economics, *Wage Price Index forecasts*, 1 April 2021, p. xiii.

89 AER, *Draft decision, United Energy distribution determination 2021–26, Attachment 6, Operating expenditure*, September 2020, pp. 43–44.

6.4.2.2 Forecast output growth

We have included forecast average annual output growth of 0.8 per cent in our alternative opex forecast. This increases our alternative estimate of total opex by $14.7 million ($2020–21) instead of $15.3 million ($2020–21) as proposed by United Energy. The difference between us and United Energy is due to updates to output weights, which are discussed below.

United Energy included an average annual output growth forecast of 0.9 per cent in its revised proposal.[90] This reflects a change from the approach it adopted to forecast output growth in its initial proposal.

In its initial proposal, United Energy proposed that we forecast output growth using only the output weights from the results of our two Cobb Douglas econometric models.[91] In our draft decision we outlined reasons why we considered all five of our economic benchmarking models should be used.[92] United Energy adopted the approach we used in our draft decision in its revised proposal.[93]

In our draft decision we stated that we would update the output weights to reflect the results from all five of our economic benchmarking models in the *2020 Annual Benchmarking Report*, which we published in November 2020.[94]

For this final decision, we have used the updated weights derived from the *2020 Annual Benchmarking Report* to forecast our alternative estimate of forecast opex. As set out below, in addition to updating these weights to reflect the results in the most recent benchmarking report, we have also considered the appropriate weights to use in response to feedback received as a part of the Victorian resets. In summary, we have forecast output growth by:

- Calculating the growth rates for three outputs (customer numbers, circuit line length and ratcheted maximum demand). This is a change from our draft decision where we also used energy throughput. United Energy used the output measures we used for our draft decision, including energy throughput.[95]
- Calculating four weighted average overall output growth rates for these three outputs using the output weights from four of the five models presented in our *2020 Annual Benchmarking Report* (see table 6.9). We did not use the opex MPFP model for this final decision. We discuss the reasons for this below.

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90 United Energy, *Revised regulatory proposal 2021–26 – MOD 10.06 – Opex*, March 2021.

91 United Energy, *Regulatory proposal 2021–26*, January 2020, pp. 157–159.

92 AER, *Draft decision, United Energy distribution determination 2021–26, Attachment 6, Operating expenditure*, September 2020, pp. 37–42.

93 United Energy, *Revised regulatory proposal 2021–26,* December 2020, pp. 119–120.

94 AER, *Draft decision, United Energy distribution determination 2021–26, Attachment 6, Operating expenditure*, September 2020, pp. 37–38.

95 United Energy, *Revised regulatory proposal 2021–26,* December 2020, p. 119.

- For our Translog models, we calculated the elasticities at the full sample mean. For our draft decisions we calculated the elasticities at the Australian sample mean, which is the approach that United Energy also adopted in its revised proposal. We discuss the reasons for this change in approach below.
- Averaging the four model specific weighted overall output growth rates.

The output weights that we have used in our alternative estimate for the final decision are set out in Table 6.9.

Table 6.9 Output weights, per cent

	Cobb-Douglas SFA	Cobb-Douglas LSE	Translog LSE	Translog SFA	Average	Draft decision average
Customer numbers	50.9	63.3	49.5	59.3	55.7	52.5
Circuit length	14.9	16.4	16.6	14.2	15.5	20.7
Ratcheted maximum demand	34.2	20.3	33.9	26.5	28.7	25.1
Energy throughput	–	–	–	–	–	1.7

Source: Economic Insights, *Memorandum prepared for the AER on review of reports submitted by CitiPower, Powercor and United Energy on opex input price and output weights*, 18 May 2020, p. 21; AER, *Draft decision, United Energy distribution determination 2021–26, Attachment 6, Operating expenditure*, September 2020, p. 37.

Note Numbers may not add up to 100 per cent due to rounding. Energy throughput is only used in the opex MPFP model.

The difference between our output growth forecasts and United Energy's updated revised proposal is due to us:

- updating output weights to reflect our 2020 annual benchmarking results as stated in the draft decision[96]
- not using the opex MPFP output weights and consequently not including energy throughput in forecasting our output growth (see below)
- using output weights from the Translog opex cost function with data normalised by the full sample means (see below).

The difference between United Energy's updated revised proposal output growth forecast and ours because of these changes is immaterial.

[96] AER, *Draft decision, United Energy distribution determination 2021–26, Attachment 6, Operating expenditure*, September 2020, pp. 37–38.

United Energy accepted our draft decision on the forecast growth of the individual output measures and we have maintained them in developing our alternative estimate.[97]

Exclusion of opex MPFP weights from our alternative output growth forecast

Our standard approach to forecast output growth has been to calculate the average output growth across all of the benchmarking models we have published in our most recent annual benchmarking report. For our draft decision this was four econometric methods (two Cobb-Douglas (CD SFA and CD LSE) and two Translog (TLG SFA and TLG LSE)) and one using the partial productivity index number method (opex MPFP).[98] In its revised proposal as part of the Victorian distribution resets, Jemena and its consultant, CEPA, submitted that it was inappropriate to use the opex MPFP output weights for the purpose of trending opex forward because they reflect drivers of total cost, not relationship between output and opex.[99] CitiPower, Powercor and United Energy also raised concerns with using the opex MPFP weights, although they did use them in their revised proposals.[100]

We agree that we should not include the opex MPFP weights in determining our forecast of output growth because they reflect drivers of, and relationship with total cost, not necessarily opex. This is consistent with our consultant, Economic Insights' view.[101] Consequently, we have not used the output weights from this model or the energy throughput as an output measure in this final decision (as the opex MPFP benchmarking is the only model that includes this output).

Translog cost function weights

For this final decision, we have calculated the Translog elasticities at the full sample mean. In our draft decision, we calculated the output weights from the translog opex cost function models at the Australian average output level rather than at the average output levels of all distributors in the international sample.[102] We adopted this approach in response to concerns raised by Frontier Economics in a report submitted with CitiPower's, Powercor's and United Energy's initial proposals.[103] Frontier Economics

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97 United Energy, *Revised regulatory proposal 2021–26,* December 2020, p. 119.

98 AER, *Draft decision, United Energy distribution determination 2021–26, Attachment 6, Operating expenditure*, September 2020, p. 37.

99 CEPA, *AERs opex benchmarking a review of the impact of capitalisation and model reliability*, December 2020, p. 27; Jemena, *Revised regulatory proposal 2021–26   Attachment 05–01, Operating expenditure*, December 2020, p. 26.

100 United Energy, *Revised regulatory proposal 2021–26,* December 2020, p. 119.

101 Economic Insights, *Economic Benchmarking Results for the Australian Energy Regulator's 2020 DNSP Annual Benchmarking Report*, October 2020, p. 5.

102 AER, *Draft decision, United Energy distribution determination 2021–26, Attachment 6, Operating expenditure*, September 2020, pp. 41–42.

103 Frontier Economics, *Review of econometric models used by the AER to estimate output growth - a report prepared for Citipower, Powercor and United Energ*y, 5 December 2019, pp. 16–18.

considered the elasticities (used to determine the output weights) should be evaluated at output levels that reflect the operating characteristics of Australian distributors.

Our consultant, Economic Insights, agreed there was some merit in normalising output variables in the opex cost function database by the respective means of the Australian sample rather than the means of the full sample as suggested by Frontier Economics.[104] However, in its 2020 Benchmarking report, Economic Insights advised against making this change until there has been sufficient opportunity to review the performance of the Translog models. The inclusion of additional data from 2019 raised a number of monotonicity violation concerns with the Australian distributors.[105] We agree with this advice and we will continue to monitor the performance of our Translog cost function as part our ongoing benchmarking development.[106]

6.4.2.3 Forecast productivity growth

Consistent with our draft decision, we have forecast annual productivity growth of 0.5 per cent.[107] This reduces our alternative estimate of total opex by $8.6 million ($2020–21). United Energy also adopted a productivity growth forecast of 0.5 per cent per year in its revised proposal, consistent with its initial proposal.[108]

6.4.3 Step changes

In its revised proposal, United Energy reproposed six of the nine step changes from its initial proposal (some with minor adjustments).

Table 6.10 summarises the step changes United Energy included in its initial and revised proposals, our draft decision and our alternative estimate for the purpose of the final decision. In its updated revised proposal, United Energy's step changes total $75.3 million ($2020–21).

We have included $70.3 million ($2020–21) for five step changes in our alternative estimate for the final decision. We have examined each step change on its own merit and whether the proposal meets the intent of what step changes should reflect as set out in the *Expenditure Forecast Assessment Guideline*.[109]

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104 Economic Insights, *Memorandum prepared for the AER on review of reports submitted by CitiPower, Powercor and United Energy on opex input price and output weights*, 18 May 2020, p. 20.

105 Economic Insights, *Economic Benchmarking Results for the Australian Energy Regulator's 2020 DNSP Annual Benchmarking Report*, October 2020, p. 13.

106 For more detail about issues on the performance of the Translog cost function of our benchmarking analysis, see: Economic Insights, *Economic Benchmarking Results for the Australian Energy Regulator's 2020 DNSP Annual Benchmarking Report*, October 2020, p. 34.

107 AER, *Draft decision, United Energy distribution determination 2021–26, Attachment 6, Operating expenditure*, September 2020, p. 43.

108 United Energy, *Revised regulatory proposal 2021–26,* December 2020, p. 119; United Energy, *Regulatory proposal 2021–26*, January 2020, p. 160.

109 AER, *Expenditure forecast assessment guideline for electricity distribution,* November 2013, p. 24.

Table 6.10 United Energy's step change proposals and our alternative estimate ($million, 2020–21)

Step change	United Energy initial proposal	AER draft decision	United Energy revised proposal	United Energy updated revised proposal	AER alternative estimate for Final Decision	Difference
Security of critical infrastructure	45.9	32.4	31.2	31.2	31.2	0.0
EPA regulations change	11.8	withdrawn	–			
Demand management programs	8.6	–	3.1	3.1	–	–3.1
IT cloud solutions	4.7	4.5	4.5	4.5	4.5	–0.0
Solar enablement	4.2	–	3.9	3.9	2.1	–1.8
5 minute settlement	3.9	3.7	3.7	3.7	3.7	–0.0
ESV levy	2.5	–	–			
Increasing insurance premiums	2.2	–	11.8	28.9	28.9	–
Financial year RIN	1.8	–	–			
Total step changes	85.6	40.6	58.2	75.3	70.3	–5.0

Source: United Energy, *Regulatory proposal 2021–26, January 2020, pp. 144, 148*; AER, *Draft decision, United Energy distribution determination 2021–26, Attachment 6, Operating expenditure*, September 2020, p. 44; United Energy, *2021–26 Revised Regulatory Proposal- MOD 10.06 - Opex*, December 2020; United Energy, *2021–26 Revised Regulatory Proposal - MOD 10.06 - Opex*, March 2021; AER analysis.

Note: Numbers may not add up to total due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

The following sections sets out the reasons for our alternative estimate of each step change.

6.4.3.1 Security of critical infrastructure

Consistent with our draft decision, our final decision is to include $31.2 million ($2020–21) for compliance with new critical infrastructure requirements in our alternative estimate.[110] This is less than the $32.4 million ($2020–21) included in our draft decision alternative estimate step change.

Table 6.11 United Energy's Security of Critical Infrastructure ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
United Energy's revised proposal	8.5	5.8	5.7	5.6	5.6	31.2
AER final decision	8.5	5.8	5.7	5.6	5.6	31.2
Difference	0.0	0.0	0.0	0.0	0.0	0.0

Source: United Energy, *Revised Regulatory Proposal 2021–26 - MOD 10.06 - Opex*, March 2021; AER analysis.
Note: Numbers may not add due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

In our draft decision we were satisfied that United Energy is subject to new regulatory obligations which require them to comply with new critical infrastructure system and data control requirements.[111] These obligations are expected to impose a major shift in the way United Energy operates its network as it transitions to compliance in accordance with the work plan approved by the Australian Government.[112]

We also noted we were satisfied there was a prudent driver for the step change proposal, but included a lower amount than proposed in our alternative estimate due to our assessment of the confidential information provided. United Energy's revised proposal accepted the reductions in the step change amount. We also noted we expect United Energy to update its step change forecast in its revised proposal following the results of a competitive tender process to ensure the step change forecast reflects the most efficient cost option. United Energy's revised proposal included an updated step change amount in its revised proposal of $31.2 million ($2020–21).[113] This was a reduction of $14.8 million ($2020–21) compared to the forecast included in the initial proposal, reflecting United Energy's assessment of the step change costs in the draft decision and the results of the competitive tender process. We consider United Energy has provided sufficient documentation to demonstrate it has undertaken market testing. We have not identified any other changes which would materially impact our assessment of the costs in the draft decision. On this basis, it is reasonable to include the proposed step change amount in our alternative estimate.

Our final decision includes some mechanical updates for inflation and price growth.

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110 AER, *Draft decision*, *United Energy determination 2021–26, Attachment 6 Operating expenditure,* September 2020 pp.45–46.

111 AER, *Draft decision, United Energy determination 2021–26, Attachment 6 Operating expenditure, September 2020 p.45.*

112 United Energy, *Regulatory proposal 2021–26,* January 2020, p. 145.

113 United Energy, *Revised regulatory proposal 2021–26,* December 2020, p. 121.

6.4.3.2 Demand management

Consistent with our draft decision, our final decision is to not include the step change for Lower Mornington Peninsula (LMP) demand management program in our alternative estimate.[114]

Table 6.12 Demand management step change ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
United Energy revised proposal	0.8	0.6	0.6	0.6	0.6	3.1
AER final decision	–	–	–	–	–	–
Difference	–0.8	–0.6	–0.6	–0.6	–0.6	–3.1

Source: United Energy, *Revised Regulatory Proposal 2021–26 - MOD 10.06 - Opex*, March 2021; AER analysis.

Note: Numbers may not add up to total due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

United Energy's original proposal included a proposed step change of $8.6 million ($2020–21) for three demand management programs. In our draft decision, we did not include the proposed step change in our alternative estimate for a number of reasons, including concerns that the step change would double count costs for the existing LMP demand management program that is already captured by other elements of the opex forecast such as the rate of change.[115] We also noted that the proposed step change amount might have been overstated as it was based on United Energy's demand forecast.[116]

In its revised proposal, United Energy included a revised step change amount of $3.1 million ($2020–21), a reduction of $5.5 million ($2020–21) from in its original proposal, for the incremental costs of continuing the LMP demand management program. United Energy did not re-propose the two other demand management programs. United Energy stated that the proposed incremental expenditure is neither captured by other opex components (e.g. rate of change or base year), nor overstated by reason of inflated demand forecasts.[117] United Energy also stated that our draft decision failed to recognise the opex/capex trade-off, creating a perverse incentive to distributors to proceed with capex even where it can be efficiently deferred.[118] It added

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[114] AER, *Draft decision, United Energy determination 2021–26, Attachment 6 Operating expenditure,* September 2020, pp.47–48.

[115] AER, *Draft decision, United Energy determination 2021–26, Attachment 6 Operating expenditure,* September 2020, pp.47–48.

[116] AER, *Draft decision, United Energy determination 2021–26, Attachment 6 Operating expenditure,* September 2020, pp.47–48.

[117] United Energy, *Revised regulatory proposal 2021–26 – Supporting document BUS 9.06 – Other step changes,* December 2020, pp. 18–19.

[118] United Energy, *Revised regulatory proposal 2021–26 – Supporting document BUS 9.06 – Other step changes,* December 2020, pp. 19–20.

that this would act as a strong disincentive for distributors to continue to develop demand management programs.[119]

United Energy considered that the proposed step change costs were reasonable, based on realistic demand forecasts. United Energy provided evidence to its forecasts for Tyabb Terminal Station (which supplies the LMP) being lower than AEMO's demand forecast for the Tyabb Terminal Station (TBTS).[120]

In its submission, the CCP17 noted that it would support a step change if our analysis can provide confidence that there is a clear link between the operating expense of the proposed demand management program and the deferral of ‘pole and wires’ augmentation’s submission.[121]

We consider our draft decision did not fail to recognise the opex/capex trade-off as our concern was not about this aspect of the step change. Our decision to not include the step change for the LMP demand management program in our alternative estimate was because including the step change in our alternative estimate of total opex would double count costs. As the LMP demand management is an existing program, we considered that:[122]

- base opex already reflects the cost of providing existing LMP demand management requirements, and
- changes in one cost category can be managed within the existing opex base as the cost of other projects or programs decline, or through the trend forecast which rolls forward base opex to capture fluctuating input costs and output growth.

We do not consider United Energy has addressed our concerns that including a step change would result in double counting costs already captured by other opex components. This outcome would be inconsistent with the operating expenditure objectives[123] as set out in the *Expenditure Forecast Assessment Guideline*.[124]

For the reasons set out above, our final decision is to not include the revised step change in our alternative estimate.

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119 United Energy, *Revised regulatory proposal 2021–26 – Supporting document BUS 9.06 – Other step changes,* December 2020, pp. 19–20.

120 United Energy, *Revised regulatory proposal 2021–26 – Supporting document BUS 9.06 – Other step changes,* December 2020, pp. 19–20.

121 CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 122.

122 AER, *Draft decision, United Energy determination 2021–26, Attachment 6 Operating expenditure, September 2020,* pp.47–48.

123 NER, cl. 6.5.6(a).

124 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 24.

6.4.3.3 IT cloud solutions

Consistent with our draft decision, our final decision is to include a step change of $4.5 million ($2020–21) for the migration of a number of ICT applications to cloud hosting in our alternative estimate.[125]

Table 6.13 United Energy's IT Cloud ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
United Energy revised proposal	0.7	0.7	1.0	1.1	1.1	4.5
AER final decision	0.7	0.7	1.0	1.1	1.1	4.5
Difference	0.0	0.0	0.0	0.0	0.0	0.0

Source: United Energy, *Revised Regulatory Proposal 2021–26 - MOD 10.06 - Opex*, March 2021; AER analysis.

Note: Numbers may not add due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

In our draft decision, we concluded that the IT cloud proposal was an efficient capex-opex trade-off and the lowest cost option to meet their ICT infrastructure needs.

United Energy's revised proposal accepted our draft decision position.[126] We have included this step change in our alternative estimate, updating the costs to account for updated inflation forecasts and our forecast of price growth for the final decision.

6.4.3.4 Solar enablement

Our final decision is to include a step change of $2.1 million ($2020–21) in our alternative estimate. This differs from our draft decision to not include this step change in our alternative estimate.[127]

Table 6.14 Solar enablement ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
United Energy revised proposal	0.9	0.8	0.8	0.7	0.8	3.9
AER final decision	0.4	0.4	0.4	0.4	0.4	2.1
Difference	–0.5	–0.3	–0.3	–0.3	–0.4	–1.8

Source: United Energy, *2021–26 Revised Regulatory Proposal - MOD 10.06 - Opex*, March 2021; AER analysis.

Note: Numbers may not add due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

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125 AER, Draft decision, *United Energy determination 2021–26, Attachment 6 Operating expenditure*, September 2020 pp.49–52.

126 United Energy, *Revised regulatory proposal 2021–26*, December 2020, pp. 120–21.

127 AER, *Draft decision, United Energy determination 2021–26, Attachment 6 Operating expenditure,* September 2020 p.52.

In our draft decision, we did not include the proposed $4.2 million ($2020–21) step change in our alternative estimate to tap down distribution transformers to remove voltage constraints, and to undertake a monitoring and compliance regime to improve compliance of inverter settings. This is due to two key reasons:[128]

- Based on advice from our consultant, EMCa, we were not satisfied United Energy had explored cost-effective options to proactively ensure correct inverter settings are applied to address non-compliance.
- We agree with our consultant, EMCa, that while the proposed tapping activities and volume are prudent and reasonable, it did not consider United Energy's unit cost of $1535 ($2020–21) is efficient, concluding that an efficient unit cost for tapping would be under $1000. Based on EMCa's advice, we adjusted United Energy's tapping costs from $3.2 million to $2.1 million or $1.8 million depending on whether a unit cost of $865 or $1000 is used. Our draft decision was that we consider these costs to be immaterial and should be managed within United Energy's total forecast opex.

In its revised proposal, United Energy continued to propose $3.9 million ($2020–21) for this step change, it submitted:[129]

- its original unit rate as it reflects the rate agreed to following a competitive tender process with its provider, Zinfra; and
- its monitoring and compliance program, as it considers the only other alternative means to ensure compliance is costly augmentation
- additionally, United Energy's revised proposal raised concerns that it was inappropriate to not include step changes in our alternative estimate on the basis of materiality in our draft decision.[130] United Energy submitted that our approach in the draft decision was not consistent with the NER, which does not stipulate a materiality threshold in the opex criteria. United Energy considered that the proposed step change represents an efficient capex/opex trade-off, and the rate of change fails to adequately capture the increasing growth in distributed energy resources.[131]

For this final decision, we have included $2.1 million ($2020–21) in our alternative estimate to undertake tapping activities at the downward adjusted cost of $1000 per unit. The reasons for this are:

- Our review of the scope of work statement included in Zinfra's $1535 unit cost found it included 'surveying, installing and removing power quality loggers, phase

[128] AER, *Draft decision, United Energy determination 2021–26, Attachment 6 Operating expenditure,* September 2020 pp.52–54.

[129] United Energy*, Revised regulatory proposal 2021–26 – Supporting document BUS 9.06 – Other step changes,* December 2020, pp. 14-18.

[130] United Energy, *Revised regulatory proposal 2021–26,* December 2020, p. 112.

[131] United Energy, *Revised regulatory proposal 2021–26 – Supporting document BUS 9.06 – Other step changes, December 2020,* p.5.

balancing and tap changing'.[132] This indicates United Energy's proposed unit cost is a blended unit rate which also includes other types of work such as voltage surveys and phase rebalancing work. As the proposed step change only includes tapping activities, we consider the unit rate cost should be adjusted to account for this.

- Based on advice from EMCa for our draft decision, we consider a unit cost for tapping of $1000 is reasonable.[133]

Consistent with our draft decision, we do not consider that United Energy's monitoring and compliance program is prudent and efficient. United Energy has not been able to justify that the proposed solution is the most cost effective option to address non-compliance of solar installations. United Energy submitted that it 'had not modelled a complete cost-benefit analysis of ensuring compliance'.[134]

We did not include this amount in our draft decision on the basis that we considered it immaterial.[135] For clarity, when we consider materiality in the context of step change assessments, what we mean is whether the costs of the step change are double counted in other elements of the opex forecast.[136] In light of the concerns raised by United Energy in relation to materiality, we have re-considered whether this step change should be included in our alternative estimate. We have included this step change in our alternative estimate on the basis that output growth does not fully account for growing distributed energy resources, and in these circumstances it may be appropriate to allow a step change for distributed energy resources management.

Therefore, for the final decision we have included an adjusted step change of $2.1 million ($2020–21) for solar enablement in our alternative estimate.

6.4.3.5 Five minute settlement

Consistent with our draft decision, our final decision is to include $3.7 million ($2020–21) in our alternative estimate.[137]

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[132] United Energy, *Information request 68, Q–3,* 7 January 2021, p.3.

[133] AER*, Draft decision, United Energy determination 2021–26, Attachment 6 Operating expenditure, September* 2020 pp. 53–54.

[134] United Energy, *Information request 68, Q–4(a),* 7 January 2021, pp.3-4.

[135] AER, *Draft Decision, United Energy 2021–26, Attachment 6 Operating expenditure,* September 2020, p. 54.

[136] AER, *Expenditure forecast assessment guideline,* November 2013. p. 24.

[137] AER, *Draft Decision*, *United Energy 2021–26, Attachment 6 Operating expenditure,* September 2020, p. 54.

Table 6.15 Five minute settlement ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
United Energy revised proposal	0.5	0.6	0.7	0.9	1.0	3.7
AER final decision	0.5	0.6	0.7	0.8	1.0	3.7
Difference	0.0	0.0	0.0	0.0	0.0	0.0

Source: United Energy, *2021–26 Revised Regulatory Proposal - MOD 10.06 - Opex*, March 2021; AER analysis.

Note: Numbers may not add due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

In our draft decision, we were satisfied that the proposal was prudent to meet the five minute settlement rule published by the AEMC on 28 November 2017[138] and made minor adjustments to the proposed cost to align with our rate of change decision.[139]

United Energy's revised proposal accepted our draft decision position.[140] We have included this step change in our alternative estimate, updating the costs to account for updated inflation forecasts and our forecast of price growth for the final decision

6.4.3.6 Insurance premiums

Our final decision is to include a step change of $28.9 million ($2020–21) for increases in insurance premiums in our alternative estimate.

Table 6.16 Insurance premiums ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
United Energy's revised proposal	3.3	5.2	6.3	6.8	7.3	28.9
AER final decision	3.3	5.2	6.3	6.8	7.3	28.9
Difference	–	–	–	–	–	–

Source: United Energy, *Revised regulatory proposal 2021–26 – MOD 10.06 – Opex*, March 2021; AER analysis.

Note: Numbers may not add due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

In United Energy's revised proposal, it proposed a combination of a step change and a cost pass through in order to recover costs related to future insurance premium cost increases. This included a step change for insurance premium increases known as a result of the latest insurance renewals ($11.8 million ($2020–21)) from its base year

138 AEMC, *Five Minute Settlement, final determination*, 28 November 2017.

139 AER, *Draft Decision*, *United Energy 2021–26, Attachment 6 Operating expenditure,* September 2020, pp. 54–56.

140 United Energy, *Revised regulatory proposal 2021–26*, December 2020, p. 116.

and a proposed cost pass through for future increases over the 2021–26 regulatory control period.[141]

Our assessment of United Energy's revised proposal revolved around two key, interrelated issues:

- whether we could estimate the prudent and efficient insurance premium forecasts over the 2021–26 regulatory control period and how much certainty there was around these forecasts
- how these costs should be recovered – via a step change or through a cost pass through mechanism.

To better understand these issues, we engaged expert consultant, Taylor Fry, to assist our assessment.[142] We asked them to review United Energy's revised proposal and the additional information that United Energy provided from its insurance brokers (Marsh) in relation to the expected insurance premium price increases over the 2021–26 regulatory control period.

The key conclusions from Taylor Fry's report are that the forecasts provided by Marsh are directionally consistent with Taylor Fry's expectations of future premiums, given its understanding of the prevailing market conditions, and can be considered reasonable. However, the advice also explains there is significant uncertainty and variability in forecasting insurance premiums over a five year period.[143]

On balance, we are of the view that in the current circumstances, while there is some uncertainty associated with forecasting insurance premium increases, we can use the forecasts of future insurance premium increases to include a step change in our alternative estimate. This position reflects our review, taking into account our consultant’s advice, on the reasonableness and likelihood of the insurance premium forecasts. It also aligns with our incentive based regulation framework, where businesses are best incentivised to achieve efficient cost outcomes by including costs in the total opex forecast. We also consider that when the step change is added to the other elements of the opex forecast, the total opex amount meets the opex criteria based on the information we have available. In reaching this position we took into account stakeholder submissions summarised below.

The VCO supported analysis of the insurance premium proposals to ensure that the step change and cost pass through events were not double counted. It noted there is support for developing the most efficient bushfire insurance program for each business with consumers sharing in the increased costs and risks, including general insurance which it considered had not been impacted by the increased bushfire risk.[144]

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[141] United Energy, *Revised regulatory proposal 2021–26*, December 2020, pp. 130.

[142] Taylor Fry, *AER AusNet Services Bushfire Insurance Public summary*, March 2021.

[143] Taylor Fry, *AER United Energy Bushfire Insurance Public summary*, March 2021, p. 3.

[144] Headberry Partners report to VCO, *Submission to Draft Determination and Revised Proposals 2.0,* January 2021, p. 56

The CCP17 submitted it is aware that insurance coverage is decreasing, while insurance costs are rising rapidly for all Australian electricity network businesses. The CCP17 viewed the changes to insurance markets to be material and beyond reasonable budget projections, with these changes likely to be sustained over a long period due to climate change. Consequently, the CCP17 accepted that the higher insurance prices are likely to remain over the coming regulatory control period.[145]

Consultant for ECA, Spencer&Co, supported the steps taken by businesses to mitigate the cost impacts of rising insurance premiums on customers. They also considered that the business' response to insurance premium increases is reasonable in the circumstances.[146]

We acknowledge the benefits of using a cost pass through for businesses to recover insurance premium costs over the next regulatory control period. These include that a cost pass through lessens the need to set a forecast when there is significant uncertainty and customers only pay for higher costs when they are known during the period. However, we consider on balance, that the long term interests of consumers is better served if the appropriate incentives remain with the businesses to actively work to moderate expected increases in insurance premiums over the next regulatory control period.

During our assessment process we shared these views with United Energy, and subsequently United Energy provided an updated revised proposal which included a step change for all insurance premium increases over the 2021–26 regulatory control period of $28.9 million ($2020–21). Based on review, including our consultant's advice, we consider this to be a reasonable forecast for United Energy and have included this amount in our alternative estimate. We also note that the rate of change increases proposed by United Energy over the 2021–26 regulatory control period generally align with the proposals from Powercor, AusNet Services and Jemena. As a result, we have not accepted the proposed insurance premiums event nominated cost pass through for the 2021–26 regulatory control period. See Attachment 15 – Pass through events for further discussion.

6.4.4 Category specific forecasts

We have included two expenditure items, debt raising costs and GSL payments, in our alternative estimate of total opex which we did not forecast using the base-step-trend approach.

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145 CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 61–63.

146 Spencer&Co report to ECA, *Submission and attachment on the Victorian EDPR Revised Proposal and Draft Decision*, January 2021, p. 15.

6.4.4.1 GSL payments

We have included GSL payments of $4.1 million ($2020–21) as a category specific forecast in our alternative estimate. This is consistent with United Energy's revised proposal and is $0.8 million ($2020–21) higher than our draft decision.[147]

The Essential Services Commission of Victoria (ESCV) concluded its review of the consumer protection framework in the Electricity Distribution Code on 16 November 2020. The final decision included updates to the GSL scheme.[148] Notably, there have been changes to the value of payments, payment thresholds and the introduction of exclusions for major event days. We stated in our draft decision that we would update our forecast of GSL payments in this final decision to reflect the revisions made to the GSL scheme by the ESCV.[149]

In its amended revised proposal, United Energy removed the GSL payments it incurred in 2019 from its base opex. It then added a category specific forecast for GSL payments equal to the average of the GSL payments it would have incurred in 2015 to 2019 had the new scheme been in place in those years. [150] We consider this is a reasonable way to forecast the impact of the changes to the scheme. This approach yields a forecast lower than the placeholder amount United Energy initially included in its revised proposal.[151]

We note that AusNet Services proposed a transition amount in addition to its forecast of GSL payments. AusNet Services stated that from 2015 to 2019, it made significant GSL payments for events that were outside of its control. Due to the changes to the GSL scheme, many of these payments were excluded from its backcast payments and thus not included in AusNet Services' forecast GSL payments for the 2021–26 regulatory control period.

We consider a 'transitional amount' is only required when there is a change in the scheme and there are abnormal events in the averaging period used to forecast GSL payments.[152]

We asked United Energy if it considered a 'transitional amount' was required and it stated that it did not.[153] We have reviewed United Energy's outages both at the customer level, and at the feeder level, and are satisfied that the outages on United Energy's network over the period 2015 to 2019 reflect normal conditions.

147 United Energy, *Revised regulatory proposal 2021–26 – MOD 10.06 – Opex*, March 2021.

148 ESC Victoria, *Electricity Distribution Code review - customer service standards, Final decision,* 16 November 2020.

149 AER, *Draft decision, United Energy determination 2021–26, Attachment 6 Operating expenditure, September 2020 p.62.*

150 United Energy, *Revised regulatory proposal 2021–26 – Supplementary revised proposal submission, December 2020,* pp.1- 2.

151 United Energy, *Revised regulatory proposal 2021–26,* December 2020, p. 122.

152 AER, *Final Decision, AusNet Services 2021–26, Attachment 6 Operating expenditure*, April 2020, section 6.4.4.1.

153 United Energy, *Information request #70,* January 2021.

Consequently, we agree that a 'transitional amount' is not necessary in United Energy's circumstances.

6.4.4.2 Debt raising costs

We have included debt raising costs of $6.0 million ($2020–21) in our alternative estimate. This is $0.03 million ($2020–21) less than the $6.1 million forecast ($2020–21) proposed by United Energy.[154]

Debt raising costs are transaction costs incurred each time a business raises or refinances debt. The appropriate 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 for consistency with the forecast of the cost of debt in the rate of return building block.

We used our standard approach to forecast debt raising costs which is discussed further in Attachment 3 to the draft decision.[155]

6.4.5 Assessment of opex factors

In deciding whether or not we are satisfied the service provider's forecast reasonably reflects the opex criteria under the NER, we have regard to the opex factors.[156]

We attach different weights to different factors when making our decision to best achieve the NEO. This approach has been summarised by the AEMC as follows:[157]

> As mandatory considerations, the AER has an obligation to take the capex and opex factors into account, but this does not mean that every factor will be relevant to every aspect of every regulatory determination the AER makes. The AER may decide that certain factors are not relevant in certain cases once it has considered them.

Table 6.17 summarises how we have taken the opex factors into account in making our final decision.

Table 6.17 Our consideration of the opex factors

Opex factor	Consideration
The most recent annual benchmarking report that has been published under rule 6.27 and the benchmark opex that would be incurred by an efficient distribution network service provider over	There are two elements to this factor. First, we must have regard to the most recent annual benchmarking report. Second, we must have regard to the benchmark operating expenditure that would be incurred by an efficient distribution network service provider over the period. The annual

[154] United Energy, *Regulatory Proposal 2021–26,* January 2020 p. 122.

[155] AER, *Draft decision, United Energy distribution determination 2021–26 – Attachment 3 – Rate of return,* September 2020, pp. 9–12.

[156] NER, cl. 6.5.6(e).

[157] AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, Final Rule Determination*, 29 November 2012, p. 115.

Opex factor	Consideration
the relevant regulatory control period.	benchmarking report is intended to provide an annual snapshot of the relative efficiency of each service provider. The second element, that is, the benchmark operating expenditure that would be incurred an efficient provider during the forecast period, necessarily provides a different focus. This is because this second element requires us to construct the benchmark opex that would be incurred by an efficient provider for that particular network over the relevant period. We have used several assessment techniques that enable us to estimate the benchmark opex that an efficient service provider would require over the forecast period. These techniques include economic benchmarking and opex cost function modelling. We have used our judgment based on the results from all of these techniques to holistically form a view on the efficiency of United Energy's proposed total forecast opex compared to the benchmark efficient opex that would be incurred over the relevant regulatory control period.
The actual and expected opex of the Distribution Network Service Provider during any proceeding regulatory control periods.	Our forecasting approach uses the service provider's actual opex as the starting point. We have compared several years of United Energy's actual past opex with that of other service providers to form a view about whether or not its revealed expenditure is efficient such that it can be relied on as the basis for forecasting required opex in the forthcoming period.
The extent to which the opex forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers.	This factor requires us to have regard to the extent to which service providers have engaged with consumers in preparing their regulatory proposals, such that they factor in the needs of consumers.[158] Based on the information provided by United Energy in its proposal and CCP17's advice, we consider that United Energy's opex forecast was developed with the influence of its consumers. We have examined the issues raised by consumers in developing our alternative estimate of opex which includes expenditure to address consumer concerns such as United Energy's consumer advisory panel supporting a conservative approach in forecasting growth due to the impact of COVID-19.[159]
The relative prices of capital and operating inputs	We have considered capex/opex trade-offs in considering United Energy's proposed step changes. For instance, we considered whether a step change for IT cloud is an efficient capex/opex trade-off. We considered the relative capex and opex costs for proposed solutions in considering this step change. We have had regard to multilateral total factor productivity benchmarking when deciding whether or not forecast opex reflects the opex criteria. Our multilateral total factor productivity analysis considers the overall efficiency of networks in the use of both capital and operating inputs with respect to the prices of capital and operating inputs.
The substitution possibilities between operating and capital expenditure.	As noted above, we considered capex/opex trade-offs in considering United Energy's proposed step changes. Some of our assessment techniques examine opex in isolation – either at the total level or by category. Other techniques consider service providers' overall efficiency, including their capital efficiency. We have relied on several metrics when assessing efficiency to ensure we

158 AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, Final Rule Determination*, 29 November 2012, pp. 101, 115.

159 United Energy, *Revised regulatory proposal 2021–26*, December 2020, p.22.

Opex factor	Consideration
	appropriately capture capex and opex substitutability. In developing our benchmarking models we had regard to the relationship between capital, opex and outputs. We also had regard to multilateral total factor productivity benchmarking when deciding whether or not forecast opex reflects the opex criteria. Our multilateral total factor productivity analysis considers the overall efficiency of networks in the use of both capital and operating inputs. Further, we considered the different capitalisation policies of the service providers' and how this may affect opex performance under benchmarking.
Whether the opex forecast is consistent with any incentive scheme or schemes that apply to the Distribution Network Service Provider under clauses 6.5.8 or 6.6.2 to 6.6.4.	The incentive scheme that applied to United Energy's opex in the 2016–20 regulatory control period, the EBSS, was intended to work in conjunction with a revealed cost forecasting approach. We have applied our estimate of base opex consistently in applying the EBSS and forecasting United Energy's opex for the 2021–26 regulatory control period.
The extent the opex forecast is referable to arrangements with a person other than the Distribution Network Service Provider that, in the opinion of the AER, do not reflect arm's length terms.	Our primary tools assess efficiency, with supporting tolls examining the efficiency of both opex and capital and inputs as well as at the category level. Given this, we are not necessarily concerned whether arrangements do or do not reflect arm's length terms. A service provider which uses related party providers could be efficient or it could be inefficient. Likewise, for a service provider who does not use related party providers. If a service provider is inefficient, we adjust their total forecast opex proposal, regardless of their arrangements with related providers. In our assessment we have not identified any such arrangements.
Whether the opex forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b).	This factor is only relevant in the context of assessing proposed step changes (which may be explicit projects or programs). We have not identified any opex project in the forecast period that should more appropriately be included as a contingent project.
The extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network alternatives.	We considered this factor in assessing United Energy's proposed demand management step change. We reviewed whether the proposed non-network costs were prudent and efficient based on the information provided by United Energy, including comparisons between network and non-network options.
Any relevant final project assessment report (as defined in clause 5.10.2) published under clause 5.17.4(o), (p) or (s)	In having regard to this factor, we must identify any regulatory investment test (RIT-D) submitted by the business and ensure the conclusions of the relevant RIT-D are appropriately addressed in the total forecast opex. We note part of the demand management step change proposed by United Energy related to an extension of the demand management solution identified in the Lower Mornington Peninsula RIT-D final project assessment report. Our assessment considered whether a step change was warranted to provide for the incremental cost of extending the demand management arrangements identified as part of the preferred option.
Any other factor the AER considers relevant and which the AER has notified the Distribution Network Service Provider in writing, prior to the submission of its revised proposal under clause 6.10.3, is an operating expenditure factor.	We did not identify and notify United Energy of any other opex factor.

Source: AER analysis.

Shortened forms

Shortened form	Extended form
ACS	alternative control services
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced metering infrastructure
CAM	Cost Allocation Method
capex	capital expenditure
CCP17	Consumer Challenge Panel, sub-panel 17
CPI	Consumer Price Index
distributor	distribution network service provider
EBSS	Efficiency Benefit Sharing Scheme
ECA	Energy Consumers Australia
ESCV	Essential Services Commission Victoria
ESV	Energy Safe Victoria
GSL	guaranteed service level
MPFP	multilateral partial factor productivity
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
NSP	network service provider
opex	operating expenditure
PPI	partial performance indicators
RBA	Reserve Bank of Australia
SCS	standard control services
utilities	electricity, gas, water and waste services
VCO	Victorian Community Organisations
WPI	Wage Price Index