Draft Decision

Essential Energy Electricity Distribution Determination 2024 to 2029

(1 July 2024 to 30 June 2029)

Attachment 20
Metering Services

September 2023

AUSTRALIAN ENERGY REGULATOR

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Contents

20 Metering Services

This attachment sets out our draft decision for the 2024–29 regulatory control period for type 5 (interval) and type 6 (accumulation) metering services for assets owned by Essential Energy.

Metering services include the maintenance, reading, data services, and the recovery of capital costs related to meters. Since the introduction of the Power of Choice reforms on 1 December 2017, Essential Energy is no longer responsible for installation of new meters and may not install any type 5 or type 6 meters from 1 April 2018. We are responsible for setting prices for Essential Energy's non-installation metering services.

Metering assets are used to measure electrical energy flows at a point in the network to record consumption for the purposes of billing. Not all customers have the same type of meter. There are different types of meters which each measure electricity usage in different ways:[1]

- Type 1 to 4 meters have a remote communication ability. We refer to these as smart meters. Type 1 to 4 metering services are contestable and therefore not regulated.
- Type 5 meters are interval meters and Type 6 meters are accumulation meters. We refer to these as legacy meters, which are being progressively replaced by smart meters.
- Type 7 metering services are unmetered connections with a predictable energy consumption pattern (for example, public lighting connections). Type 7 metering services are a monopoly provided service and are covered by our determination on standard control services.

Distributors also provide some non-routine metering services which are charged to customers when requested, such as meter disconnection. These non-routine metering services are fee-based Ancillary Network Services, which are discussed in attachment 16.

In this attachment, we:

- Provide a background to recent changes affecting metering services, including the decision framework, and the impacts of the AEMC's metering review on this draft decision (section 20.1). It applies to all distributors in NSW, ACT and Tasmania.
- Set out our draft decision (section 20.2), which draws on the reasons in Appendix A.
- Summarise Essential Energy's proposal (section 20.3).
- Set out the reasons for our draft decision (Appendix A).
- Set out our draft decision price caps for type 5 (interval) and type 6 (accumulation) routine metering services (Appendix B).

1 AER, *Final framework and approach for Ausgrid, Endeavour Energy and Essential Energy for the 2024-29 regulatory control period*, July 2022, pp. 28–29.

20.1 Background

20.1.1 Transition to smart metering

The 2017 Power of Choice reforms removed the distributors' ability to provide new meters to customers and intended to introduce competition for providing and servicing meters by other meter providers in the NEM.[2] New standards mean only smart meters (mostly type 4 meters for residential customers) with remote communications may now be installed.

However, the take up of smart meters has been slow. Essential Energy has forecast a legacy meter population of just over one million meters in 2023–24 being 81% of the legacy metering asset base when the reforms were introduced.[3]

In August 2023, the Australian Energy Market Commission (AEMC) completed its review of the regulatory framework for metering services (the metering review). The AEMC review looked at how to expedite the uptake of smart meters. The AEMC's report noted that smart meters provide whole-of-system benefits which should be realised as soon as possible.[4]

As such, the metering review recommends a target of universal take-up of smart meters by 2030 in NEM jurisdictions. This recommendation would have the most impact in New South Wales, the Australian Capital Territory, Queensland and South Australia. Tasmania has a program in place to accelerate smart meter deployment by 2026. Victoria has already achieved a near universal uptake of smart meters.[5]

To achieve this outcome, the AEMC has proposed a framework where distributers to develop legacy metering retirement plans (LMRPs) in consultation with retailers, metering parties, and other stakeholders. It is envisaged the LMRPs will schedule bulk meter replacements (retailers to replace legacy meters with smart meters) on a geographical basis to leverage economies of scale. Customers may have little choice as to when their legacy meter will be replaced as the replacement process will be determined by the distributors and other providers.

With metering services classified as ACS and costs allocated to a declining customer base, Essential Energy's customers with meters replaced later in the deployment may be charged inequitably higher costs for metering services than customers with meters replaced earlier, even though there is no change in the service they receive. This arises because:

- Large fixed-cost base will be recovered over a rapidly declining number of customers (e.g. systems and IT, base labour force)
- Per unit costs to read a meter increase as it is further to travel between each meter.

2 This does not apply to the Northern Territory and Victorian customers are covered by state regulation that places responsibility for metering with the distributors.

3 Essential Energy, *13.02.06 Standardised Metering Pricing Model Public,* 31 January 2023.

4 AEMC, *Final report Metering review*, August 2023, p. 13.

5 AEMC, *Final report Metering review*, August 2023, p. iii.

- Some costs that are necessary for the transition, such as site remediation, may also occur within the 2024–29 period. As the rate of replacement increases, more of the sites requiring remediation will be brought forward into the 2024–29 period.

20.1.2 Changes to regulatory settings

In making our draft decision, we have had regard to the metering review and how to address potential inequity in metering service costs as a result of the metering transition. For our draft decision, we have retained the current classification for metering service costs but set price caps to reflect 100% smart meter deployment by 2030 and also protect customers from price shocks. However, as discussed below, we consider changes to the classification and form of control for metering service costs are likely to be more appropriate in the revised proposals. Our draft decision applies the following regulatory settings:

- The classification as alternative control services is retained.
- The price cap form of control is retained, which sets the maximum fixed prices distributors can charge per customer.
- The price caps are set with the expectation that distributors will recover costs from all low voltage customers who have had a legacy meter, instead of an ever-decreasing population of customers with legacy meters.
- The price caps are set to recover the revenue requirement as a whole (one price), rather than separate capital and non-capital components for recovery from different customer bases as per the approach in the 2019–24 period.
- The legacy metering asset base is subject to accelerated depreciation to fully depreciate the asset base within the 2024–29 regulatory period. This reflects a change in the remaining life of the assets due to the metering review.
- It is assumed that the meter replacement rate will accelerate along a straight line from 2025 to achieve 100% deployment at the end of the 2029–30 financial year.[6]

The central goal of this change is to ensure that potentially vulnerable customers are protected from rising costs. This change ensures no customer is worse off due to when their legacy meter is replaced. It also ensures a more equitable contribution to the roll out of smart meters by all customers, since all customers benefit from the transition.

However, we consider a reclassification of legacy metering services as standard control services (SCS) and with costs recovered through the revenue cap is likely to be more appropriate in the revised proposals in order to reduce material price impacts for customers through the metering transition. Contribution by all customers is appropriate as all energy users will recognise the network benefits of this transition.

We consider the recommendations of the metering review to be a material change in circumstances that supports a departure from the F&A.[7] We encourage the distributors to

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6 We set this path based on the best information available to us at the time of our draft decision. We expect actual rates of replacement to be different to this linear path, and for some exceptions to be made for meters with complicating factors.

7 AER, *Final framework and approach for Ausgrid, Endeavour Energy and Essential Energy for the 2024-29 regulatory control period*, July 2022, p. 29.

engage with stakeholders in considering this change in classification and form of control for their revised proposals. We consider it important that a reclassification of metering services as SCS would need to retain the current level of transparency through the continued use of the standardised metering models.

20.2 Draft decision

Given the above noted changes to the regulatory settings, our draft decision is to not accept Essential Energy's proposed prices for type 5 (interval) and type 6 (accumulation) routine metering services for the following reasons:

- We do not accept Essential Energy's metering opex, particularly relating to the trend component. We apply an updated trend of metering volumes, weighting of volume trend, labour cost escalation, and inflation.[8]
- We substitute our depreciation schedules to apply accelerated depreciation of both the RAB and new capex allocated during the 2024–29 period.
- We do not accept Essential Energy's annual revenue requirement, which needs to be revised to reflect the updated building blocks.
- We do not accept Essential Energy's price cap calculation for legacy metering services, and substitute our price cap calculation which reflects the recovery of costs through a fixed fee charged to a wider customer base.

We expect Essential Energy to submit a revised proposal that reflects the outcomes of the metering review, including the metering volume trends and opex step changes.

[8] AER, *Rate of Return Instrument 2022*. The 2022 Rate of Return Instrument was amended in August 2023. See https://www.aer.gov.au/publications/guidelines-schemes-models/rate-of-return-instrument-2022/final-decision.

20.3 Essential Energy's proposal

Consistent with our F&A Paper, Essential Energy proposed that legacy metering services be classified as alternative control services (ACS) and regulated under a price cap (see Appendix A.1).

As the provision of these services is subject to the progressive retirement of legacy meters Essential Energy's proposal is based on the historical rate of replacement. Essential Energy proposed to retire 26% of its legacy meters, leaving 787,447 legacy meters in place in 2028–29.[9]

20.3.1 Metering revenue

Essential Energy proposed a total expected revenue of $198.5 million ($nominal) for the 2024–29 period. To determine its proposed revenue requirement Essential Energy used the AER's standardised metering models which applies the building block approach to determine allowable revenue. Essential Energy's proposed annual revenue requirement and building blocks are set out in Table 20.1.

Table 20.1 Essential Energy's proposed building blocks and annual revenue requirement ($million, nominal)

Building block component	2024–25	2025–26	2026–27	2027–28	2028–29	Total
Return on capital	4.5	4.2	3.9	3.6	3.2	19.4
Return of capital (regulatory depreciation)	8.0	8.6	9.2	9.8	10.4	45.9
Operating expenditure	25.2	25.7	25.9	26.1	26.2	129.2
Revenue adjustments	–	–	–	–	–	–
Net tax allowance	0.7	0.8	0.8	0.8	0.9	4.0
Annual revenue requirement (unsmoothed)	**38.5**	**39.2**	**39.8**	**40.2**	**40.7**	**198.5**

Source: Essential Energy, *13.02.03 Metering PTRM*, January 2023

Capex

Essential Energy proposed total net capex of $11.9 million ($2023–24) for the 2024–29 period.[10] This includes the cost of assets such as depots and communications technology which enable Essential Energy to deliver these services.[11] Essential Energy did not propose any direct capex because direct capex relates to investment in new assets and Essential Energy is not allowed to install new meters.

[9] Essential Energy, *13.02.06 Standardised Metering Pricing Model Public,* January 2023.

[10] Essential Energy, *13.02.03 Metering PTRM Public,* January 2023.

[11] A relevant allocation of this indirect capex to legacy metering services is calculated in line with Essential Energy's applicable Cost Allocation Methodology. Essential Energy, *Cost Allocation Methodology,* October 2022.

Opex

Essential Energy's proposed opex of $119.8 million ($2023–24) for the 2024–29 period includes the costs of performing routine meter reading activities, routine testing and maintaining meters. Essential Energy developed its opex forecast using the 'base-step-trend' approach, consistent with the standardised models, the approach for SCS, and the approach used in the 2019–24 period. Essential Energy included an adjustment to its base opex but no step changes to its opex.[12]

To establish the trend in opex over the 2024–29 period, Essential Energy applied the following factors:[12]

- declining number of meters
- real price changes in labour costs
- an adjustment reflecting the growing diseconomies of scale
- an adjustment for annual productivity improvements
- a weighting of 61% variable and 39% fixed costs.

Regulatory depreciation

Essential Energy proposed straight line depreciation for both the opening RAB and capex incurred in the 2024–29 period. The forecast closing metering regulatory asset base is a mix of metering and shared assets, totalling 45.9 million ($nominal).[13] Essential Energy did not propose accelerated depreciation for the metering asset base.

20.3.2 Pricing

Essential Energy proposed to calculate its price caps for metering services using the AER's standardised metering pricing model and the building blocks from the post tax revenue model. The standardised metering pricing model separated the building block components across the capital and non-capital categories, and then smooths these amounts over the 2024–29 period. The model determines the relevant price caps for the capital and non-capital charging components of each tariff.

The table below shows Essential Energy's proposed metering price caps for selected customer types (and volume weighted average) in the 2024–29 period.

12 Essential Energy, *13.02.02 Standardised Metering Capex and Opex Model,* January 2023.

13 Essential Energy, *13.02.03 Metering PTRM Public,* January 2023.

Table 20.2 Essential Energy's proposed price cap per meter, selected customer types ($p.a. nominal)

Customer type	Component	2024–25	2025–26	2026–27	2027–28	2028–29
Non ToU (Residential and Small Business)	Non-capital	37.94	41.97	46.43	51.36	56.81
	Capital	12.47	12.77	13.07	13.38	13.70
ToU (Residential and Small Business)	Non-capital	56.91	62.95	69.63	77.02	85.20
	Capital	18.16	18.59	19.03	19.48	19.94
Volume weighted average (all tariffs)	Non-capital	25.19	27.11	29.05	30.93	32.67
	Capital	10.08	10.32	10.57	10.82	11.08

Source: Essential Energy, *13.02.06 Standardised Metering Pricing Model*, January 2023.

A. Reasons for draft decision

A.1 Classification and form of control

Our draft decision retains the classification of metering as ACS and the form of control as price caps.

In our Final F&A, we classified legacy metering services as ACS and noted we would depart from these settings if the metering review constituted a “material change in circumstances”. As such, the ACT, NSW and TAS distributors’ initial proposals are based on F&A settings with the view that they would be reviewed following the release of the AEMC’s final metering review report.[14]

We consider the metering review has resulted in a material change in circumstances, due to the requirement to replace all legacy meters by 2030, as well as the changes to regulated expenditure to support the metering transition. We therefore consider that it would be appropriate to reclassify legacy metering services as SCS in the revised proposals. In the interim, we have proposed changes to the regulatory settings as noted in section 20.1.2. Since these changes affect inputs in the calculation, we have substituted alternative calculations for the affected building blocks, which will need to be updated in the revised proposal. As noted in section 20.1.1, if we do not make any changes to how price caps are determined some customers may experience inequitable price increases as more meters are replaced. As such, our draft decision seeks to mitigate the inequitable price increases to individual customers by recovering costs across a wider customer base. This is achieved by recovering costs from all low voltage customers who have or have had a legacy meter. Our draft decision also reflects the recommendations of the metering review, which will accelerate the transition, reinforcing the necessity to mitigate the inequitable effects in the 2024–29 period.

However, the most equitable solution appears to be recovery of legacy metering costs across all customers. We consider cost recovery for the metering transition across all customers appropriate as all customers will receive the whole-of-system benefits the smart meters will provide. This would be done by reclassifying metering services as SCS. That said, we have chosen to maintain legacy metering services as ACS in our draft decision due to the timing of the AEMC’s final decision as we need additional time to work through the implications of a reclassification to SCS.

We engaged with distributors on this reclassification and they were supportive of the proposal to reclassify metering services as SCS. We encourage the distributors to now engage with stakeholders in considering this change in settings for their revised proposals. As we progress toward our final decision, we will work with all distributors and stakeholders to establish guidance on a common approach to reclassification as SCS.

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14 AEMC, *Final report Metering review*, August 2023.

If legacy metering services are reclassified as SCS, we would seek to maintain use of the standardised metering models to provide transparency of the metering costs for stakeholders and for other processes.

A.2 Smart meter deployment rates

Our draft decision is to maintain historical legacy meter replacement rates until 2024–25 when the acceleration program begins, then apply a linear profile to reflect the target 100% deployment by 2030. For our draft decision we have had consideration of the recommendation from the metering review to accelerate the replacement of legacy meters to target 100% deployment by 2029–30.

The metering review recommendations require the distributors to develop LMRPs which come into effect in 2024–25. As such, although some acceleration is already occurring, we have elected to maintain historical rates of replacement until the acceleration program begins in 2024–25. This is due to the planning required as well as sourcing of materials and resources to support the accelerated replacements to target full deployment by 2030.

Our application of a linear profile between 2024–25 and 2029–30 leads to 20% of 2024–25 meters remaining at the end of the 2024–29 period. When we engaged with distributors about the effects of the metering review draft report and the possibility of reclassification to SCS, some distributors proposed lower rates of replacement. Distributors submitted alternative rates of replacement to the end of the 2024–29 period ranging from 62% to 89%, which they noted are dependent on a number of assumptions such as the inclusion of a true-up mechanism. These rates were estimated before the metering review final report was released, based on acceleration, and expected refusal rates. In Essential Energy's proposal, 78% of 2024–25 legacy meters will remain in 2028–29.[15]

Our analysis shows that, generally, there is no significant variance in bill impacts between 100% deployment by 2029–30 and the distributors alternative churn rates. At most, reducing the target as proposed by distributors would only result in a 2% increase in prices, relative to our preferred replacement profile.

Because of the remaining uncertainty around actual rates, rather than adopting case-by-case assumptions, we prefer to apply a standardised input for our draft decision. We expect the rate of replacement to be different in the revised proposals to account for exceptions that the metering review recommendations allow for.

A.3 Annual revenue requirement

Our draft decision is for a total annual revenue requirement (ARR) of $226.2 million ($nominal) for Essential Energy over the 2024–29 period. This is an increase of $27.7 million ($nominal) or 13.9% to Essential Energy's proposed total ARR of $198.5 million ($nominal) for this period. This reflects the impact of our draft decision on the various building block costs.

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15 Essential Energy, *13.02.06 Standardised Metering Pricing Model*, January 2023.

Table A.1 Annual revenue requirement (unsmoothed, $million nominal)

Annual revenue requirement	2024–25	2025–26	2026–27	2027–28	2028–29
Essential Energy initial proposal	38.5	39.2	39.8	40.2	40.7
Draft decision	45.4	48.1	47.2	45.0	40.4

Source: Essential Energy, *13.02.03 Metering PTRM*, 31 January 2023; AER, *Draft decision - Essential Energy distribution determination 2024–29 - Metering PTRM*, September 2023.

We assessed Essential Energy's metering proposal by analysing the metering Post-tax Revenue Model (PTRM) and the roll-forward model (RFM). In doing this we had regard to the outcomes of the AEMC’s metering review which might affect inputs into the elements of the PTRM and RFM.

The AER’s PTRM calculates the ARR for each year of the 2024–29 period. This unsmoothed ARR for each year is the sum of the building block costs.

Table A.2 shows the total building block costs that form the ARR and where discussion on the elements that drive these costs can be found within this draft decision.

Table A.2 Metering building block components ($million nominal)

Building block component	Total – Essential Energy's proposal	Total – draft decision	Section where element is discussed
Return on capital	19.4	15.3	A.5
Return of capital (regulatory depreciation)	45.9	90.3	A.6
Operating expenditure	129.2	116.6	A.8
Revenue adjustments	–	–	–
Net tax allowance	4.0	3.9	–
Revenue requirement	**198.5**	**226.2**	**A.3**

Source: Essential Energy, *13.02.03 Metering PTRM*, 31 January 2023; AER, *Draft decision - Essential Energy distribution determination 2024–29 - Metering PTRM*, September 2023.

A.4 Regulatory asset base

Our draft decision accepts Essential Energy’s asset roll forward and calculation method, but we have substituted values based on updated inputs, including capex and inflation. We expect that in the revised proposal both the opening RAB and treatment of the RAB in the 2024–29 period will be updated to reflect revised inputs.

The value of the RAB impacts Essential Energy's revenue requirement, and the price consumers ultimately pay. Other things being equal, a higher RAB would increase both the return on capital and return of capital (depreciation) components of the distribution determination. This draft decision sets out:

- the opening RAB as at 1 July 2024
- the forecast closing RAB as at 30 June 2029
- a profile of accelerated depreciation as set out in section A.6.

Table A.3 Summary of asset roll forward ($million nominal)

Summary of asset roll forward	Essential Energy's proposal	Draft decision
Opening RAB	79.6	79.5
Net capex (total nominal)	13.0	13.1
Regulatory depreciation (total nominal)	54.4	97.5
Inflation on opening RAB (total nominal)	8.5	7.2
Forecast closing RAB	46.6	2.4

Source: Essential Energy, *13.02.03 Metering PTRM*, 31 January 2023; AER, *Draft decision - Essential Energy distribution determination 2024–29 - Metering PTRM*, September 2023.

We use the RFM to roll forward Essential Energy's RAB over from the 2019–24 period to arrive at an opening RAB value at 1 July 2024. This roll-forward calculation accounts for inflation, the weighted average cost of capital, actual net capex and actual depreciation. The amounts are estimated based on forecasts where actuals data is not available.

The opening RAB may also be adjusted to reflect any changes in the use of the assets, with only assets used to provide metering services to be included in the RAB. No such adjustments were included in the draft decision.

The PTRM used to calculate the annual revenue requirement for the 2024–29 period generally adopts the same RAB roll-forward approach as the RFM, although the annual adjustments to the RAB are based on forecasts, rather than actual amounts.

A.5 Rate of Return

Our draft decision on legacy metering services applies the same rate of return as applied throughout our determination, which is set out in Attachment 3.

Attachment 3 states that the draft decision uses the 2022 rate of return instrument, which was used along with placeholder interest rates by Essential Energy to develop its regulatory proposal.

We have used updated rates in our draft decision, and we expect that the rates used in the revised proposal will also be updated to reflect the latest information available. This includes rates for return on debt, inflation, and equity raising costs.

A.6 Regulatory depreciation

Our draft decision rejects the depreciation schedules proposed by Essential Energy, and substitutes depreciation schedules with straight-line accelerated depreciation to fully depreciate the asset base within the 2024–29 period. Our draft decision updates the asset life of the opening RAB to 5 years and substitutes a standard asset life of 1 year for all capex incurred in the 2024–29 period. This reflects our consideration that the economic life of metering assets has effectively been reduced.

Depreciation is the return of capital over the economic life of the asset. In deciding whether to approve the depreciation schedules submitted by Essential Energy, we make determinations on the indexation of the RAB and depreciation building blocks for Essential Energy's 2024–29 period. The regulatory depreciation amount is the depreciation less the indexation of the RAB.

We determine the regulatory depreciation amount using the PTRM. The calculation of depreciation in each year is governed by the value of assets included in the RAB at the beginning of the regulatory year, and by the depreciation schedules.[16]

Our standard approach to calculating depreciation is to employ the straight-line method set out in the PTRM, but other methods are also considered. We must consider whether the proposed depreciation schedules conform to the following key requirements:[17]

- the schedules depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets.
- the sum of the real value of the depreciation that is attributable to any asset or category of assets must be equivalent to the value at which that asset or category of assets was first included in the RAB for the relevant distribution system.

To the extent that a distributor's building block proposal does not comply with the above requirements, then we must determine the depreciation schedules for the purpose of calculating the depreciation for each regulatory year.[18]

We assess Essential Energy's proposed standard asset lives against:

- the approved standard asset lives in the distribution determination for the 2019–24 period
- the standard asset lives of comparable asset classes approved in our recent distribution determinations for other service providers
- the appropriate economic lives of the assets.

Our standard approach for depreciating a distributor's existing assets in the PTRM uses the remaining asset lives at the start of a regulatory control period as determined in the RFM.

In this case we consider that the appropriate economic life of the metering asset base may be different to the standard asset lives due to the accelerated deployment of legacy meters. Our standard assumption is to wind up the metering asset base in the 2024–29 period. Asset

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16 NER, cl. 6.5.5(a).

17 NER, cl. 6.5.5(b).

18 NER, cl. 6.5.5(a)(2)(ii).

lives should fit within this timeframe, which is to say less than 5 years' remaining life for all assets at the start of the regulatory control period.

Applying accelerated depreciation over the 2024–29 period to our draft distribution determinations for the ACT, NSW and TAS results in a low-level increase (up to $8 per annum) in prices for some distributors. These impacts are within a reasonable expectation of short-term cost increases in order to deliver the benefits of the transition to smart metering.

A.7 Capital expenditure

Our draft decision is to accept Essential Energy's proposed forecast capex of $11.9 million ($2023–24).[19]

This estimate is based on the allocation of shared expenditure, and our expectation is that the revised proposal will include updated allocations of this expenditure.

A.8 Operating expenditure

Our draft decision is to not accept Essential Energy's proposed forecast opex of $119.8 million ($2023–24).[20] Our draft decision includes an alternate estimate of $107.8 million ($2023–24).[21]

Our draft decision and Essential Energy's proposal both use the base-step-trend method to calculate forecast opex for the 2024–29 period. Due to the uncertainty around opex, which depends both on the content of the LMRPs that have not yet been developed and the actual rate of replacement by all actors involved, the draft decision also includes a true up mechanism for opex.

Base opex

If we find the business is operating efficiently, our preferred methodology is to use the business's historical or 'revealed' costs in a recent year as a starting point for our opex forecast. For the draft decision the base opex is taken to be the opex in 2022–23, and we accept the proposed adjustment to the base opex of $0.10 million. This base opex is based on forecasts and our expectation is that it will be updated for actual opex in the revised proposal.

Rate of Change

We trend base opex forward by applying our forecast 'rate of change'. We estimate the rate of change by forecasting the expected growth in input prices, outputs and productivity.

We forecast input price growth using a combination of labour and non-labour price change forecasts. Labour costs represent a significant proportion of a distributor's costs.[22] We use input price weights between labour and non-labour components consistent with SCS.

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19 Essential Energy, *13.02.02 Standardised Metering Capex and Opex Model,* January 2023.

20 Essential Energy, *13.02.02 Standardised Metering PTRM Public,* January 2023.

21 AER, *Draft decision – Essential Energy distribution determination 2024–29 Metering PTRM*, September 2023.

22 AER, *Expenditure forecast assessment guideline –distribution*, August 2022, pp. 25–26.

We forecast the change in output (number of meters) to account for the annual change in operational costs to provide metering services. Our draft decision accepts Essential Energy's proposed weighting of 61% variable and 39% fixed costs. The change in variable costs is determined based on the change in output using a productivity factor. In addition to this weighting, an issue has been identified with the formulation of the productivity factor calculation, where the calculated change in costs is less accurate for larger relative changes in output. Distributors may wish to address this issue in their revised proposals.

As more legacy meters are retired, the average metering cost per customer is expected to rise due to higher travel costs of individual meter reads. For Essential Energy, the proposed opex is compared with our draft decision opex to illustrate the impact of the changes in volumes in Table A.4.

Table A.4 Forecast opex and national metering indicator (NMI)

	2024–25	2025–26	2026–27	2027–28	2028–29	Total
Essential Energy's proposed NMI volumes	540,907	489,990	438,167	385,438	331,804	–
Essential Energy's proposed opex ($million, 2023–24)	24.6	24.4	24.1	23.6	23.2	119.8
Draft decision NMI volumes	548,861	439,089	329,317	219,544	109,772	–
Draft decision opex ($million, 2023–24)	25.2	24.2	22.7	20.3	15.5	107.8

Source: Essential Energy, *13.02.02 Standardised Metering Capex and Opex Model*, 31 January 2023; AER, *Draft decision - Essential Energy distribution determination 2024–29 - Metering expenditure model*, September 2023
Note: Both our draft decision and Essential Energy's proposal apply a weighting of 61% variable and 39% fixed costs. NMI volumes, rather than meter volumes, are used to trend opex in line with Essential Energy's proposal.

Step changes

Lastly, we add or subtract any components of opex that are not appropriately compensated for in base opex or the rate of change, but which should be included in the forecast total opex to meet the opex criteria.[23]

Our draft decision accepts Essential Energy's proposal of no step changes. In the revised proposal step changes are expected to reflect the recommendations of the metering review. An example of costs that may be included or reclassified and included are bulk remediation activities within the 2024–29 period made necessary by the adoption of the 100% deployment target by 2030.

True-up mechanism for opex

The draft decision applies a straight-line profile to replace all remaining meters between 2025 and 2030, as described in section A.2.

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

Although the distributors are responsible for making the LMRPs, the actual replacement in a retailer-led smart meter roll out is out of their control. A key concern is that the LMRPs will not be finalised before our final decisions are made. The replacement profiles in our final decision may not align with the LMRPs, and the actual replacement rates may not reflect the profiles from the LMRPs. This exposes the distributors to a misalignment in cost recovery.

We will apply a true-up of total metering opex through the price cap formulae to manage this misalignment (see Attachment 14). This is similar to other opex true ups for expenditure that is out of the control of the distributor (e.g., Tasmanian licence fees, small customer gas abolishment costs).

A.9 Price caps

Our draft decision does not accept Essential Energy's price cap calculation for the recovery of legacy metering costs. Our draft decision substitutes the price caps presented in Appendix B. These price caps reflect the revised revenue requirement and the recovery of costs from a wider customer base through the use of a fixed fee charged to all low voltage historical legacy metering customers.

Price caps are determined based on the unsmoothed annual revenue requirement. In the process of setting price caps an iterative calculation is used to 'smooth' and flatten the price paths for cost recovery across the 2024–29 period. We set a real price path on revenues and front load the annual change to reduce price volatility over the period. This flattened price path is consistent with our current approach to ACS, and will help to manage the price increases that may eventuate at the retail level as a result of the accelerated deployment of smart meters.

Cost recovery customer base

The draft decision maintains the tariff structure but allocates costs across all low voltage customers who have or have had a legacy meter.

At the network level, recovering legacy metering costs from a wider customer base will mean that some consumers will pay significantly less while others pay slightly more than they otherwise would. We consider this outcome is appropriate for two reasons:

- First, as noted by the AEMC, the accelerated smart meter deployment seeks to provide system wide benefits to all consumers.[24] As such, we consider it appropriate that all consumers contribute to the realisation of these system wide benefits.
- Second, it mitigates the inequitable legacy metering costs incurred by those who have their legacy meters replaced late in LMRP implementation. Essential Energy's proposal would result in an increase of metering charges for remaining customers from $31.97 per meter in 2023–24 to $43.74 per meter in 2028–29. This effect is then exponentially greater at the tail end of the deployment in the following years.

The current framework for the cost recovery of legacy meters involves a separation of metering charges into capital and non-capital charges. These are charged to relevant individual customers and are regulated under a price cap. Customers who have had a

[24] AEMC, *Final report Metering review*, 30 August 2023, p. iii.

distributor-owned meter historically are subject to capital charges. Customers who continue to use a distributor-owned meter are subject to both capital and non-capital charges.[25] New dwellings do not incur legacy metering charges from the distributor.

Cost recovery for legacy metering in our draft decision covers both capital and non-capital components of building block expenditure, and is applied to a common customer base. Our draft decision metering revenue is to be recovered across all low voltage customers who have or have had a legacy meter. If legacy metering services are classified as SCS in the revised proposals then costs will be recovered across all customers.

The impacts of changing the population for cost recovery on selected price paths in the draft decision are illustrated in Table A.5.

Table A.5 The effect of cost recovery changes, selected customer types ($p.a. nominal)

Customer type		2023–24	2024–25	2025–26	2026–27	2027–28	2028–29
Non ToU (Residential and Small Business) – capital and non-capital	Approved	42.44					
	Proposed		50.41	54.74	59.50	64.74	70.51
	Draft decision		**43.58**	**44.80**	**46.05**	**47.34**	**48.67**
ToU (Residential and Small Business) – capital and non-capital	Approved	63.17					
	Proposed		75.07	81.54	88.66	96.50	105.14
	Draft decision		**64.87**	**66.68**	**68.55**	**70.47**	**72.44**
Volume weighted average – capital and non-capital	Calculated	31.97					
	Proposed		35.27	37.44	39.62	41.75	43.74
	Draft decision		**32.82**	**33.74**	**34.69**	**35.66**	**36.66**

Source: Essential Energy, *13.02.06 Standardised Metering Pricing Model*, 31 Jan 2023; AER, *Draft decision - Essential Energy distribution determination 2024–29 - Metering PTRM*, September 2023.

Residential and small business consumers in the ACT, NSW and Tasmania that still have legacy meters in the final year of the 2024–29 period will save up to $65 due to legacy metering costs being recovered from historical legacy metering customers as set out in the draft decision.[26] This may represent an important saving for vulnerable customers.

It should be noted that these bill impacts may not be experienced by all consumers as retailers often recover the combined legacy and smart metering charges across their

25 There may be some customers who have obtained a legacy meter from another party than the distributor and may only pay the non-capital charges for the ongoing services related to maintaining this meter.

26 This is compared to outcomes of our draft decision if costs were not recovered across a wider customer base, and includes smoothing of costs over the period. If compared to a scenario where both smoothing and cost recovery basis changes were not applied, the savings would be much greater, up to $600 in the final year.

customer base. Recovering these costs from all customers at the network level will ensure a more equitable outcome across all customers, irrelevant of retailer.

We note that maintaining metering as ACS but recovering costs from a wider customer base is considered a transitional solution to support the accelerated deployment of legacy meters as the number of customers who have a legacy becomes much smaller. We consider it appropriate to integrate metering services into SCS at some point in time. At the very least this would be residuals in a future regulatory period but could also be in the revised proposal, which would also allow cost recovery across all customers, rather than only historical legacy metering customers.

B. Metering price caps

Table B.1 X factors for each year of the 2024–29 regulatory control period for metering services, draft decision (per cent)

	2025–26	2026–27	2027–28	2028–29
X factor	0%	0%	0%	0%

Note: We apply 0% X-factors as we set a real flat price path for years 2–5 to reduce volatility of prices.

Table B.2 Draft decision metering price caps ($p.a. nominal)

Metering tariff	2024–25 price cap
Residential Non ToU	$43.58
Residential ToU	$64.87
Controlled load	$13.22
Small Business Non ToU	$43.58
Small Business ToU	$64.87

Shortened forms

Term	Definition
ACS	alternative control services
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
ARR	annual revenue requirement
capex	capital expenditure
MAR	maximum allowed revenue
NEM	national electricity market
NER	national electricity rules
NSP	network service provider
opex	operating expenditure
PV	photovoltaic
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
RIN	regulatory information notice
RFM	roll forward model
SCS	standard control services
STPIS	service target performance incentive scheme
TNSP	transmission network service provider
WACC	weighted average cost of capital