Draft Decision

Ergon Energy Electricity Distribution Determination 2025 to 2030

(1 July 2025 to 30 June 2030)

Attachment 20
Metering Services

September 2024

AUSTRALIAN ENERGY REGULATOR

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20 Metering Services

This attachment sets out our draft decision for the 2025–30 regulatory control period (period) for type 5 (interval) and type 6 (accumulation) metering services for assets owned by Ergon 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, Ergon 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 Ergon 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 Australian Energy Market Commission's (AEMC) review of the regulatory framework for metering services (the AEMC's metering review) on this draft decision (section 20.1).[2]
- Set out our draft decision (section 20.2), which draws on the reasons in Appendix A.
- Summarise Ergon Energy's proposal (section 20.3).
- Set out the reasons for our draft decision (Appendix A).

Mount Isa-Cloncurry Network

Ergon Energy also services networks and communities that are not connected to the national electricity market (NEM). Of these networks, only services delivered to the customers of the

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1 AER, *Final Framework and Approach - Ergon and Energex 2025–30*, June 2023, p. 30.

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

Mt Isa-Cloncurry (MI-C) network are classified as a regulated service (see Attachment 13 – Classification of services). As the MI-C network is not connected to the NEM, the Power of Choice reforms and the AEMC's metering review do not apply. This means Ergon Energy is the monopoly provider of metering services to the MI-C network and is responsible for the installation of new meters (including smart meters).

We set out our draft decision and relevant considerations for metering services for the MI-C network under separate sub-headings throughout this attachment.

For the avoidance of doubt, electricity services provided to customers in other local community electricity networks that are not connected to the NEM other than the MI-C network are unregulated services, and the relevant metering services are not considered in this decision (see Attachment 13 – Classification of services). However, we note that like the MI-C network, we consider that Ergon Energy should endeavour to transition these customers to smart meters by 2030, as recommended across the NEM by the AEMC's metering review.[3]

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.[4] New standards mean only smart meters (mostly type 4 meters for residential customers) with remote communications may now be installed.

The take up of smart meters across the NEM has generally been slow. Ergon Energy has forecast a legacy meter population of over 555,590 meters in 2024–25, being 42% of the legacy metering asset base when the reforms were introduced.[5]

In August 2023, the AEMC completed its metering review. The AEMC's metering review looked at how to expedite the uptake of smart meters. The AEMC noted that smart meters provide whole-of-system benefits which should be realised as soon as possible.[6]

As such, the AEMC's metering review recommended 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.[7]

To achieve this outcome, the AEMC proposed a framework where the distributors develop legacy meter retirement plans (LMRPs) in consultation with retailers, metering parties, and

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3 AEMC, *Final report Metering review*, August 2023, p. i.

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

5 AER analysis; Ergon Energy, *10.02 - Metering Expenditure Model 2025-30*, January 2024; AER, *Final decision – Ergon Energy distribution determination 2020–25 - Metering PTRM*, June 2020.

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

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

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.

Through this process, customers may have little choice as to when their legacy meter will be replaced, as this will be determined by the distributors and other providers.

If distributors maintained the 2020–25 regulatory settings for metering services with costs allocated to a declining customer base, 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:

- A 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 the average distance travelled between each meter increases.

The AEMC is scheduled to announce its final determination for the accelerated smart meter deployment rule change on 28 November 2024, after the release of this draft decision. We will consider any further impacts from this rule change as part of our final decision.

Mount Isa-Cloncurry Network

As the Power of Choice reforms and the AEMC's metering review do not apply to the MI-C network, Ergon Energy is the monopoly provider of metering services. This means that Ergon Energy is responsible for the transition to smart metering for these customers.

Despite being outside the AEMC's metering review, we consider that the transition to smart meters in the MI-C network should reflect that of the NEM.

20.1.2 Changes to regulatory settings

Our draft decision had regard to the AEMC's metering review and how to address potential inequity in recovering metering service costs because of the metering transition. It applies the following regulatory settings:

- The reclassification of most legacy metering services (maintenance, reading, and data services) from alternative control services (ACS) to standard control services (SCS) and use of a revenue cap. For more information see Attachment 13 - Classification of services and Attachment 14 – Control mechanisms.
- A revenue cap which recovers legacy metering costs through a flat per customer charge to all low voltage (LV) customers, rather than separate recovery of capital and non-capital costs from different customer types as per the 2020–25 period.
- The legacy metering asset base is subject to accelerated depreciation to fully depreciate the asset base within the 2025–30 period. This reflects a change in the remaining life of the assets due to the AEMC's metering review.

- The forecast meter replacement rate will not achieve 100% deployment by the end of the 2029–30 financial year due to sites that are scheduled to be replaced after 1 July 2030 or sites where the replacement is scheduled but unable to be completed.[8]

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 as a result of 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.

We consider the recommendations of the metering review to be a material change in circumstances that supports a departure from the classification of services and the form of control set in the Framework and Approach paper (F&A).[9] We consider it important that a reclassification of metering services as SCS needs to retain the current level of transparency through the continued use of the standardised metering models.

Mount Isa-Cloncurry Network

We consider it appropriate to apply the same regulatory settings to the MI-C network, and to group the recovery of MI-C metering services costs with the recovery of those costs in respect of Ergon Energy's NEM-connected customers. This ensures consistency in application, equitable treatment and costs regardless of location, and reduces administrative burden that would result from managing separate asset bases or maintaining MI-C network metering services as ACS.

20.2 Draft decision

Given the above noted changes to the regulatory settings, our draft decision is to not accept Ergon Energy's proposal as submitted. Our draft decision is to:

- Accept Ergon Energy's proposal for no capital expenditure (capex).
- Substitute an alternate forecast metering operating expenditure (opex) applying a bottom-up approach based on information received from Ergon Energy.
- Accept Ergon Energy's application of accelerated depreciation to the regulated asset base.
- Substitute our annual revenue requirement, which applies our substitute inputs as noted above.
- Accept Ergon Energy's reclassification to SCS and application of a revenue cap form of control.
- Accept Ergon Energy's proposed recovery of costs through a flat per customer charge to LV customers, regardless of customer, tariff, or meter type.

Mount Isa-Cloncurry Network

Our draft decision relates to both NEM-connected legacy metering services and MI-C network metering services. This includes the reclassification of MI-C network metering

8 Ergon, *Attachment 19 - Legacy Metering,* January 2024, p. 10.

9 NER, cl. 6.12.3(b).

services to SCS and the application of a revenue cap (See Attachment 13 – Classification of Services and Attachment 14 – Control Mechanisms).

20.3 Ergon Energy's proposal

Ergon Energy proposed to reclassify legacy metering services as SCS and for such services to be regulated under a revenue cap.

Mount Isa-Cloncurry Network

Ergon Energy proposed to include the MI-C network as metering SCS even though they are not subject to the Power of Choice reforms. Ergon Energy reasoned it would be administratively burdensome to treat the MI-C network differently as the metering costs for the MI-C network (1% of Ergon Energy's customers) are immaterial relative to the overall metering costs.

20.3.1 Metering revenue

Ergon Energy proposed a total annual revenue requirement (ARR) of $179.7 million ($nominal, smoothed) for the 2025–30 period.[10] To determine its proposed revenue requirement, Ergon Energy used the AER's standardised metering models which apply the building block approach to determine allowable revenue. Ergon Energy's proposed ARR and building blocks are set out in Table 20.1.

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

Building block component	2025–26	2026–27	2027–28	2028–29	2029–30	Total
Return on capital	2.6	2.1	1.7	1.2	0.6	8.1
Return of capital (regulatory depreciation)	7.5	7.9	8.4	8.9	9.4	42.2
Operating expenditure	25.4	25.6	25.8	26.1	26.1	128.9
Revenue adjustments	-	-	-	-	-	-
Net tax allowance	-	-	-	-	-	-
ARR (unsmoothed)	**35.4**	**35.6**	**35.9**	**36.1**	**36.1**	**179.2**
ARR (smoothed)	**33.9**	**34.9**	**35.9**	**37.0**	**38.1**	**179.7**

Source: Ergon Energy, *10.04 – Metering PTRM 2025–30*, January 2024.

20.3.1.1 Capital expenditure

Ergon Energy did not propose any direct capex because Ergon Energy is not allowed to install new meters.

[10] Ergon Energy, *10.04 – Metering PTRM 2025–30*, January 2024.

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Ergon Energy proposed to forego capex related to the MI-C network. Ergon Energy noted in a response to an information request that they had considered treating capex for the MI-C network as a direct expense under opex. However, due to these amounts being approximately $12,000 per year they decided to forego including this expenditure in the cost recovery build-up.[11]

20.3.1.2 Operating expenditure

Ergon Energy's proposed opex of $128.9 million ($nominal) for the 2025–30 period includes the costs of performing meter maintenance as well as routine meter reading and testing.[12] Ergon Energy proposed an opex forecast using the 'base-step-trend' approach, consistent with the standardised models, the approach for SCS, and the approach used in the 2020–25 period.

Ergon Energy's proposal did not include any adjustments to its base opex or any step changes over the 2025–30 period. In response to a request for additional information, Energex provided a bottom-up calculation of opex that was used to determine annual opex over the 2025–30 period and, subsequently, to calculate the trend factors required to reproduce that opex in the AER's standardised model.[13] This bottom-up opex forecast included components that would otherwise be considered as base adjustments and step changes in a top-down opex approach.

20.3.1.2.1 Legacy meter retirement rates

Ergon Energy forecast to retire 68% of its legacy meters over the 2025–30 period (compared to remaining legacy meters in 2024–25), leaving 177,351 legacy meters in place in 2029–30.[14]

Ergon Energy has proposed to replace 10% to 17% of legacy meters each year during the period.[15] Based on evidence from the Victorian smart meter rollout, Ergon Energy anticipates 15% of sites will not be upgraded by the end of June 2030.[16]

Mount Isa-Cloncurry Network

Ergon Energy proposed to continue to group opex related to the MI-C network with opex related to the NEM-connected network.[17] This includes incorporating the MI-C network meters in proposed legacy meter retirement rates above.

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11 Ergon Energy, *Information request #043 – Legacy Metering,* June 2024.

12 Ergon Energy, *10.04 – Metering PTRM 2025–30*, January 2024.

13 Ergon Energy, *Information request #051 – Legacy Metering,* June 2024.

14 Ergon Energy, *10.02 - Metering expenditure model 2025–30*, January 2024.

15 AER analysis; Ergon Energy, *10.02 - Metering expenditure model 2025–30*, January 2024.

16 Ergon Energy, *2025–30 Regulatory proposal*, January 2024, p. 185.

17 Ergon Energy, *2025–30 Regulatory proposal*, January 2024, p. 183.

20.3.1.3 Regulatory depreciation

Ergon Energy proposed straight line accelerated depreciation for the opening regulatory asset base (RAB) in the 2025–30 period.[18] Ergon Energy proposed accelerating the depreciation for its metering RAB to help manage the overall costs for consumers of the smart meter rollout, in line with the AER's guidance.[19] The asset base is proposed to be fully depreciated by the end of the 2025–30 period.

Mount Isa-Cloncurry Network

Ergon Energy proposed to continue to group the MI-C network metering assets with the NEM-connected network metering assets,[20] and therefore to apply the same approach to regulatory depreciation for all metering assets.

20.3.2 Pricing

Ergon Energy proposed to calculate its revenue cap for legacy metering services using the building blocks from the post tax revenue model (PTRM). Ergon Energy proposed to recover the relevant revenue cap from LV customers through a flat per customer charge, as per our guidance and 2024–29 determinations.[21]

Mount Isa-Cloncurry Network

Ergon Energy proposed to continue to socialise cost recovery across both the MI-C and NEM-connected networks.[22]

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18 Ergon Energy, *2025–30 Regulatory proposal*, January 2024, p. 185.

19 AER, *Legacy metering services - guidance for revised proposals*, November 2023.

20 Ergon Energy, *2025–30 Regulatory proposal*, January 2024, p. 183.

21 Ergon Energy, *10.05 - Metering pricing model 2025–30*, January 2024.

22 Ergon Energy, *2025–30 Regulatory proposal*, January 2024, p. 183.

A Reasons for draft decision

A.1 Classification and form of control

Our draft decision accepts Ergon Energy's proposal to reclassify its legacy metering services from ACS to SCS and recover costs through the revenue cap form of control. Under a revenue cap, we set the maximum revenue Ergon Energy can earn for metering services for the first year of the 2025–30 period. For all subsequent years of the 2025–30 period, revenues will be adjusted by the applicable control mechanism formula set out in Attachment 14. This mechanism adjusts revenue caps annually for inflation, an X factor, and any other relevant adjustments. We also support the recovery of metering costs through a flat per customer charge to LV customers.

In our final F&A, we classified legacy metering services as ACS. We also noted that our draft determinations for the New South Wales, Australian Capital Territory, Tasmania, and Northern Territory distributors along with the final outcomes of the AEMC's metering review would constitute a 'material change in circumstances' that would allow a departure from the F&A.[23] As such, we accept Ergon Energy's proposal to depart from the F&A by reclassifying metering as SCS. Consistent with the reasoning in our guidance,[24] this approach mitigates inequitable price increases that some customers could have experienced and supports the transition to the whole of system benefits that smart meters will provide.

Ergon Energy has broad stakeholder support for its approach. The Reset Reference Group (RRG), Master Electricians Australia (MEA), and CCP30 supported the proposed changes to the recovery of metering costs to provide a fair and equitable outcome for consumers.[25] The RRG also noted that the proposed charging arrangement supports the objectives of the smart meter rollout,[26] and that customers supported the proposed changes during pre-lodgement engagement.[27]

We also accept Ergon Energy's revised proposal to recover metering costs through a flat per customer charge to LV customers. We consider this approach to be equitable and transparent and is also consistent with the reasoning in our guidance.[28]

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23 AER, *Final Framework and Approach - Ergon and Energex*, June 2023, pp. 6 & 30.

24 AER, *Legacy metering services - guidance for revised proposals*, November 2023.

25 Energy Queensland Regulatory Reset Group, *RRG Independent Engagement Report Energex Final*, June 2024, p. 26; Master Electricians Australia, *Submission - 2025–30 Electricity Determination – Ergon Energy*, May 2024, p. 4; Master Electricians Australia, *Submission - 2025–30 Electricity Determination – Ergon Energy*, May 2024, p. 4.

26 Energy Queensland Reset Reference Group, *Submission on Ergon Energy and Energex electricity distribution regulatory proposals 2025–30 and the Australian Energy Regulator's Issues Paper*, May 2024, p. 68.

27 Energy Queensland Reset Reference Group, *Submission on Ergon Energy and Energex electricity distribution regulatory proposals 2025–30 and the Australian Energy Regulator's Issues Paper*, May 2024, p. 68.

28 AER, *Legacy metering services - guidance for revised proposals*, November 2023.

We consider that transparency recovering metering costs over the 2025–30 period is important. As such, Ergon Energy will report metering charges separately to other SCS charges in its annual pricing proposals to maintain this transparency.

Mount Isa-Cloncurry Network

Our draft decision accepts Ergon Energy's proposal to reclassify MI-C metering services from ACS to SCS and recover costs through the revenue cap form of control. We also accept Ergon Energy's proposal to continue to combine recovery of these costs with the legacy metering services for NEM-connected customers.

We consider that the AEMC's metering review being a 'material change in circumstances' for the NEM-connected legacy meters also applies to the MI-C metering services. We agree with Ergon Energy that this treatment will reduce administrative burden. We also consider that consistency in treatment produces the most equitable outcome for all customers regardless of location and aligns with the objectives of the AEMC's metering review and the Queensland Government's targets related to smart meter deployment across all of Queensland. [29]

The RRG and CCP30 supported aligning the approach for MI-C metering services with that of the NEM-connected legacy metering services to reduce burden and to ensure MI-C customers were not left behind in the rollout. However, both the RRG and CCP30 were concerned about the lack of customer engagement undertaken on the proposed approach to the MI-C network.[30] We encourage Ergon Energy to consult with all affected stakeholders in future processes.

A.2 Annual revenue requirement

Our draft decision is for a total ARR of $170.9 million ($nominal, smoothed) for Ergon Energy over the 2025–30 period.[31] This is a decrease of $8.8 million ($nominal) or -4.91% from Ergon Energy's proposed total ARR of $179.7 million ($nominal, smoothed) for this period. This reflects the impact of our draft decision on the various building block costs listed in Table A.2.

Our draft decision applies a flat real price path for years 2–5. This is done by applying 0% X factors in these years. This means that any real price movement is applied in the 2025–26 year. We consider this provides the most certainty and will best support the likely increases in metering costs in the retail component as the rollout is delivered.

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29 Queensland Government, *Queensland energy and jobs plan*, September 2022, p. 37.

30 Energy Queensland Reset Reference Group, *Submission on Ergon Energy and Energex electricity distribution regulatory proposals 2025–30 and the Australian Energy Regulator's Issues Paper*, May 2024, pp. 68; CCP30, *Response EQL Issues Paper and proposal*, May 2024, p. 39.

31 AER, *Draft decision – Ergon Energy distribution determination 2025–30 - Metering PTRM*, September 2024.

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

Annual revenue requirement	2025–26	2026–27	2027–28	2028–29	2029–30
Ergon Energy initial proposal	35.4	35.6	35.9	36.1	179.2
Draft decision	35.7	34.5	33.5	33.2	33.2
Draft decision (smoothed)	32.3	33.2	34.2	35.1	36.1

Source: Ergon Energy, *10.04 - Metering PTRM 2025–30*, January 2024; AER, *Draft decision - Ergon Energy distribution determination 2025–30 - Metering PTRM*, September 2024.

We assessed Ergon Energy's metering proposal by analysing the metering 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 2025–30 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 – initial proposal	Total – draft decision	Section where element is discussed
Return on capital	8.1	8.0	A.4
Return of capital (regulatory depreciation)	42.2	42.0	A.5
Operating expenditure	128.9	120.0	A.7
Revenue adjustments	-	-	-
Net tax allowance	-	-	-
Revenue requirement	**179.1**	**170.0**	**A.2**

Source: Ergon Energy, *10.04 - Metering PTRM 2025–30*, January 2024; AER, *Draft decision - Ergon Energy distribution determination 2025–30 - Metering PTRM*, September 2024.

Mount Isa-Cloncurry Network

Our draft decision for the annual revenue requirement as detailed above covers both NEM-connected legacy metering services and MI-C network metering services.

A.3 Regulatory asset base

Our draft decision accepts Ergon Energy's asset roll forward and calculation method, but we have substituted values based on updated inflation inputs. We expect that in the revised proposal both the opening RAB and treatment of the RAB in the 2025–30 period will be updated to reflect any revised inputs available.

The value of the RAB impacts Ergon 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 2025
- the forecast closing RAB as at 30 June 2030
- 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	Initial proposal	Draft decision
Opening RAB	42.2	42.0
Net capex (total nominal)	-	-
Regulatory depreciation (total nominal)	-45.9	-45.7
Inflation on opening RAB (total nominal)	3.7	3.7
Forecast closing RAB	0.0	0.0

Source: Ergon Energy, *10.04 - Metering PTRM 2025–30*, January 2024; AER, *Draft decision - Ergon Energy distribution determination 2025–30 - Metering PTRM*, September 2024.

We use the RFM to roll forward Ergon Energy's RAB over from the 2020–25 period to arrive at an opening RAB value at 1 July 2025. 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 2025–30 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.

Mount Isa-Cloncurry Network

Our draft decision accepts Ergon Energy’s proposal to continue to combine the MI-C metering services assets and the NEM-connected legacy metering service assets in the same RAB to reduce administrative burden.

A.4 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. This includes updated rates for return on debt, inflation, and equity raising costs.

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.5 Regulatory depreciation

Our draft decision accepts the depreciation schedules proposed by Ergon Energy, with straight-line accelerated depreciation to depreciate the asset base within the 2025–30 period.

Depreciation is the return of capital over the economic life of the asset. In deciding whether to approve the depreciation schedules submitted by Ergon Energy, we make determinations on the indexation of the RAB and depreciation building blocks for Ergon Energy's 2025–30 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.[32]

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. Ergon Energy adopted our standard assumption to wind up the metering asset base in the 2025–30 period.

The RRG supported this approach given the small bill impact over the 2025–30 period.[33]

Mount Isa-Cloncurry Network

Our draft decision for regulatory depreciation as detailed above applies to both NEM-connected legacy metering services and MI-C network metering services.

A.6 Capital expenditure

Our draft decision is to accept Ergon Energy’s proposed zero capex.[34]

Mount Isa-Cloncurry Network

Our draft decision is to accept Ergon Energy’s proposal to forego the recovery of capex for MI-C network metering assets. We consider this outcome to be advantageous for consumers, and reduces the administrative burden involved in maintaining an asset base for such a small number of assets.

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32 NER, cl. 6.5.5(a).

33 Energy Queensland Regulatory Reset Group, *RRG Independent Engagement Report Ergon Final*, June 2024, p. 26.

34 Ergon Energy, *10.04 - Metering PTRM 2025–30*, January 2024.

A.7 Operating expenditure

Our draft decision is to not accept Ergon Energy's proposal forecast opex of $128.9 million ($nominal).[35] Our draft decision includes an alternate estimate of $120.0 million ($nominal) reflecting a bottom-up estimate provided by Ergon Energy, as well as updates to labour cost escalation and inflation.[36]

Ergon Energy's proposal provided a top-down forecast opex for the 2025–30 period in line with the base-step-trend approach in the AER's standardised metering model. In response to a request for additional information, Ergon Energy provided a bottom-up forecast opex that was used to determine trend factors for the top-down approach.[37] We have used this bottom-up forecast opex for our draft decision, as discussed below.

We note there is uncertainty around opex. This is because it depends both on the content of the LMRPs (which distributors have not yet developed) and the actual rate of meter replacement. Hence the draft decision also includes a true up mechanism for opex.

Table A.4 below compares our draft decision opex to Ergon Energy's proposed forecast opex.

Table A.4 Proposal and draft decision meter volumes and opex

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
Meter volumes (accepted)	461,030	366,471	290,823	234,087	177,351	
Ergon Energy's proposed opex ($million, nominal)	25.4	25.6	25.8	26.1	26.1	128.9
Draft decision opex ($million, nominal)	25.7	24.5	23.5	23.2	23.2	120.0

Source: Ergon Energy, *10.04 Metering PTRM 2025–30,* January 2024; AER, *Draft decision – Ergon Energy distribution determination 2025–30 - Metering PTRM*, September 2024.

Mount Isa-Cloncurry Network

Our draft decision accepts the inclusion of forecast metering opex for the MI-C network in the proposed metering opex forecast. This inclusion ensures consistency with our approach for other building blocks. We are satisfied that inputs that sit within the forecast, including the unit cost, are applicable to both the MI-C network and the NEM.

Base-step-trend opex forecast

We raised concerns regarding the rates of change applied in the trend component of Ergon Energy's proposal.[38] We were concerned that the economies of scale and the variable costs factors did not align with the factors from our 2024–29 determinations for other networks with similar characteristics. We were also concerned that the factors set out in Ergon Energy's proposal were the same for both the Energex and Ergon Energy networks, despite being

35 Ergon Energy, *10.04 - Metering PTRM 2025–30*, January 2024.

36 AER, *Draft decision - Ergon Energy distribution determination 2025–30 - Metering PTRM*, September 2024.

37 Ergon Energy, *Information Request #051 – Legacy metering*, July 2024.

38 AER, *Information Request #051 – Legacy metering*, June 2024.

quite different in geographical characteristics. We requested further information from Ergon Energy to support these factors.

Ergon Energy provided a bottom-up calculation of opex that was used to determine annual opex over the 2025–30 period, and subsequently the trend factors required to reproduce that opex in the AER's standardised model.[39] Ergon Energy noted its proposal used this approach to be consistent with the AER's standardised metering expenditure model. Given this context, we consider it more appropriate to assess the bottom-up opex approach that underlined Ergon Energy's proposal in our draft decision, rather than assess the top-down approach Ergon Energy provided in its proposal.

Bottom-up opex forecast

In its bottom-up opex forecast, Ergon Energy provided additional information on unit rates for contracted services, trend factors for those unit rates over declining volumes, and breakdowns of activities and relevant expenditure over the 2025–30 period.[40] Ergon Energy also provided context on their procurement processes and other relevant considerations affecting its bottom-up opex forecast.[41]

Based on our analysis and the supporting information, we consider these forecasts are prudent and efficient. Ergon Energy's opex per customer is lower than that approved for Essential Energy. We consider Essential Energy to be the most comparable network for Ergon Energy based on geographical characteristics, being a key factor relating to the economies of scale in metering opex.

Legacy meter replacement rates

Our draft decision accepts the legacy meter replacement rates as proposed.

Ergon Energy's proposal is to replace 10% to 17% of legacy meters each year during the period.[42] Ergon Energy anticipated there will be 15% of sites exempted and not upgraded by the end of June 2030.[43] This is based on the Victorian smart meter roll out. We consider Ergon Energy's forecast to be appropriate and within expectations of the AEMC's metering review.

MEA suggested introducing alternative incentives to stimulate increased adoption of smart meters to ensure the shared cost does not demotivate those who are yet to adopt smart meters from doing so.[44] We consider that the AEMC's metering review has appropriately addressed incentives for the rollout of smart meters.

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39 Ergon Energy, *Information Request #051 – Legacy metering*, July 2024.

40 Ergon Energy, *Information Request #061 – Legacy metering*, August 2024.

41 Ergon Energy, *Information Request #061 – Legacy metering*, August 2024.

42 AER analysis; Ergon Energy, *10.02 - Metering expenditure model 2025–30*, January 2024.

43 Ergon Energy, *2025–30 Regulatory proposal*, January 2024, p. 185.

44 Master Electricians Australia, *Submission - 2025–30 Electricity Determination – Ergon Energy*, May 2024, p. 4.

Mount Isa-Cloncurry Network

Our draft decision accepts Ergon Energy's proposal to accelerate the rollout of smart meters across the MI-C network on the same timeline as the accelerated smart meter rollout for the NEM.

Ergon Energy is working with metering coordinators and other providers on an agreement to give effect to this. While the agreement has been established, the details of the replacement plan is yet to be finalised. Ergon Energy expected the non-NEM rollout plan to be drafted in July/August 2024, and the program to begin in early 2025.[45]

The Queensland Farmers Federation's (QFF) submission supported the roll-out and deployment of smart meters by 2030 in principle, aligning with the target under the Queensland Energy and Jobs Plan.[46] They stressed that their support lies in supporting their members' individual strategies for digital meter installations in their respective regions. The QFF also stressed that the affordability of installation costs is paramount.

True-up mechanism for opex

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). For the avoidance of doubt, no components of opex other than meter volumes will be updated through this true-up mechanism.

To give form to this true-up mechanism, Ergon Energy will need to provide an amended bottom-up opex model in their revised proposal that makes relevant components of the cost build-up a product of volumes. This will allow forecast volumes to be updated for actual volumes for the purposes of this true-up adjustment.

45 Ergon Energy, *Information request #057 – Legacy Metering*, July 2024.

46 QFF, *Submission to AER - AER Issues Paper 2025-30 Regulatory Proposals Provided by Ergon and Energy Queensland*, June 2024, p. 10.

Shortened forms

Term	Definition
ACS	alternative control services
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
ARR	annual revenue requirement
capex	capital expenditure
CCP30	Consumer Challenge Panel Sub-Panel 30
LMRP	legacy meter retirement plan
LV	low voltage
MEA	Master Electricians Australia
MI-C	Mt Isa-Cloncurry
NEM	national electricity market
NER	national electricity rules
opex	operating expenditure
PTRM	post-tax revenue model
QFF	Queensland Farmers' Federation
RAB	regulatory asset base
RFM	roll forward model
RRG	Regulatory Reset Group
SCS	standard control services