Final Decision

Ergon Energy Electricity Distribution Determination 2025 to 2030

(1 July 2025 to 30 June 2030)

Attachment 20
Metering Services

April 2025

AUSTRALIAN ENERGY REGULATOR

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1	30 April 2025	13

List of attachments

This attachment forms part of the Australian Energy Regulator’s (AER's) final decision on the distribution determination that will apply to Ergon Energy for the 2025–30 period. It should be read with all other parts of the final decision.

As a number of issues were settled at the draft decision stage or required only minor updates, we have not prepared all attachments. Where an attachment has not been prepared, our draft decision reasons form part of this final decision. The final decision attachments have been numbered consistently with the equivalent attachments to our draft decision.

The final decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

Attachment 13 – Classification of services

Attachment 14 – Control mechanisms

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Attachment 18 – Connection policy

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Attachment 20 – Metering services

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20 Metering Services

This attachment sets out our final decision for the 2025–30 regulatory control period (period) for type 5 (interval) and type 6 (accumulation) metering service assets owned by Ergon Energy.

Metering services include 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. We are responsible for setting revenues for Ergon Energy's 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. These are the subject of this final decision.
- 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.[2]

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 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 (metering review) on this final decision (section 20.1).[3] We also provide a summary of our draft decision.
- Set out our final decision (section 20.2), which draws on the reasons in Appendix A.
- Summarise Ergon Energy's revised proposal (section 20.3).
- Set out the reasons for our final decision (Appendix A).

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

2 Other new meters (type 8 and type 9) are being considered to replace type 7 meters, which are reduced capability smart meters intended to manage predictable loads like public lighting connections.

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

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 Mt Isa-Cloncurry (MI-C) network are subject to economic regulation by the AER under Chapter 6 of the NER and therefore classified by the AER[4] (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 final 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 local community electricity networks that are not connected to the NEM other than the MI-C network are not subject to economic regulation by the AER under Chapter 6 of the NER. As a result the relevant metering services in those areas are not considered in this decision (see Attachment 13).

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.[5] 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 forecast a legacy meter population of 555,590 meters in 2024–25, being 42% of the legacy metering asset base when the reforms were introduced in 2017.[6]

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.[7] The review focussed on 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.[8]

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4 Section 10, *Electricity - National Scheme (Queensland) Act 1997*

5 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.

6 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.

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

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

As a result of the metering review, the AEMC made the *Accelerating smart meter deployment* rule change determination on 28 November 2024. This established a program to deliver an efficient rollout of smart meters to all customers by 2030.[9]

To achieve this outcome, the AEMC's final rule established a clear target in the NER for the accelerated deployment of smart meters by 30 November 2030. To facilitate industry collaboration on the delivery of these smart meters, the rule established the Legacy Meter Replacement Plan (LMRP) mechanism and new obligations on retailers in relation to the LMRP and related targets.[10] It is expected the LMRPs will schedule bulk meter replacements (retailers to replace legacy meters with smart meters) on a geographical basis to leverage economies of scale.[11]

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 accelerated 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.

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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, including the 2030 timeframe.

20.1.2 Our draft decision

While the *Accelerating smart meter deployment* rule change determination had not been made, our draft decision had regard to the metering review and how to address potential inequity in metering service costs resulting from the metering transition. It applied the following regulatory settings:[12]

[9] AEMC, *Final rule determination, Accelerating smart meter deployment*, 28 November 2024, pp. 1–2.

[10] AEMC, *Final rule determination, Accelerating smart meter deployment*, 28 November 2024, p. 9.

[11] AEMC, *Final rule determination, Accelerating smart meter deployment*, 28 November 2024, p. 124.

[12] AER, *Draft Decision Attachment 20 - Metering Services - Ergon Energy - 2025–30 Distribution revenue proposal*, September 2024, pp. 3–4.

- The reclassification of legacy metering services from alternative control services (ACS) to standard control services (SCS). For more information see Attachment 13 – Classification of services.
- Application of 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 in the 2020–25 period). For more information see Attachment 14 – Control mechanisms.
- The accelerated depreciation of the regulated asset base 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.
- A forecast meter replacement that reflected that 100% deployment by the end of the 2029–30 financial year would not be achieved 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.

The central goal of these changes was to ensure that customers who may experience vulnerability are protected from rising costs. We considered these changes ensured no customer would be worse off as a result of when their legacy meter is replaced under an LMRP. Further, it ensured a more equitable contribution to the roll out of smart meters by all customers since all customers benefit from the transition.

Our draft decision considered the recommendations of the metering review a material change in circumstances that supported a departure from the classification of services and the form of control set in the Framework and Approach paper (F&A).[13] We also considered it important that a reclassification of metering services as SCS retain the current level of transparency through the continued use of the standardised metering models.

Noting all of the above, our draft decision accepted Ergon Energy's proposal for no capital expenditure (capex) and application of accelerated depreciation, as well as the reclassification of metering to SCS with a revenue cap form of control. We substituted an alternate forecast metering operating expenditure (opex) and annual revenue requirement. We also accepted Ergon Energy's proposed cost recovery approach.[14]

Mount Isa-Cloncurry Network

Our draft decision applied the same regulatory settings to the MI-C network and grouped recovery of MI-C metering services costs with the recovery of those costs associated with Ergon Energy's NEM-connected customers.[15] This ensured 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.

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13 NER, cl. 6.12.3(b).

14 AER, *Draft Decision Attachment 20 - Metering Services - Ergon Energy - 2025–30 Distribution revenue proposal*, September 2024, p. 4.

15 AER, *Draft Decision Attachment 20 - Metering Services - Ergon Energy - 2025–30 Distribution revenue proposal*, September 2024, pp. 4–5.

20.2 Final Decision

Our final decision is to not accept Ergon Energy's revised proposal as submitted. Our final decision is to:

- Maintain our draft decision capex[16] forecast which Ergon Energy accepted in its revised proposal.
- Substitute a revised metering opex forecast to apply updates to forecast inflation.
- Maintain our draft decision to apply accelerated depreciation to the regulated asset base,[17] which Ergon Energy accepted in its revised proposal.
- Substitute our annual revenue requirement to apply updates to forecast inflation and inputs related to the 2022 rate of return instrument, as well as our substituted opex forecast.
- Maintain our draft decision to reclassify metering as SCS and apply a revenue cap form of control[18] which Ergon Energy accepted in its revised proposal.
- Maintain our draft decision to recover costs through a flat per customer charge to LV customers, regardless of customer, tariff, or meter type[19] which Ergon Energy accepted in its revised proposal.

The reasons for our final decision are provided at Appendix A.

Mount Isa-Cloncurry Network

Our final decision relates to both NEM-connected legacy metering services and the MI-C network metering services. This includes the reclassification of MI-C network metering services to SCS and the application of a revenue cap (See Attachment 13 – Classification of Services and Attachment 14 – Control Mechanisms).

We have not provided additional reasoning for our final decisions as they relate to the MI-C network in Appendix A. Our draft decision provides reasoning for our decisions as they relate to the MI-C network. Our reasoning is unchanged for our final decision.

20.3 Ergon Energy's revised proposal

Ergon Energy accepted our draft decision, with some updates to inputs (rates of return) to reflect the latest information available.[20] This included accepting the reclassification of legacy metering services as SCS and for metering services to be regulated under a revenue cap. [21]

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16 AER, *Draft Decision Attachment 20 - Metering Services - Ergon Energy - 2025–30 Distribution revenue proposal*, September 2024, p. 12.

17 AER, *Draft Decision Attachment 20 - Metering Services - Ergon Energy - 2025–30 Distribution revenue proposal*, September 2024, p. 12.

18 AER, *Draft Decision Attachment 20 - Metering Services - Ergon Energy - 2025–30 Distribution revenue proposal*, September 2024, pp. 8–9.

19 AER, *Draft Decision Attachment 20 - Metering Services - Ergon Energy - 2025–30 Distribution revenue proposal*, September 2024, pp. 8–9.

20 Ergon Energy, *2025–30 Revised Regulatory proposal*, November 2024, p. 118.

21 Ergon Energy, *2025–30 Revised Regulatory proposal*, November 2024, p. 129; Ergon Energy, *2025–30 Revised Regulatory proposal*, November 2024, p. 131.

Mount Isa-Cloncurry Network

Ergon Energy's revised proposal applied the settings we accepted in our draft decision, which was to combine cost recovery for MI-C customers with NEM-connected customers.

20.3.1 Metering revenue

Ergon Energy proposed a total annual revenue requirement (ARR) of $170.7 million ($nominal, smoothed) for the 2025–30 period.[22] 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 revised proposal 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	2.5	2.0	1.6	1.1	0.6	7.8
Return of capital (regulatory depreciation)	7.4	7.9	8.4	8.9	9.4	42.0
Operating expenditure	25.7	24.5	23.5	23.2	23.2	120.0
Revenue adjustments	-	-	-	-	-	-
Net tax allowance	-	-	-	-	-	-
ARR (unsmoothed)	**35.6**	**34.4**	**33.5**	**33.1**	**33.1**	**169.8**
ARR (smoothed)	**32.3**	**33.2**	**34.1**	**35.1**	**36.1**	**170.7**

Source: Ergon Energy, *10.03 - Metering PTRM 2025–30*, November 2024.
Note: Amounts are inclusive of the MI-C network.

20.3.1.1 Capital expenditure

Ergon Energy accepted our draft decision for a total net capex of $0.0 million ($2024–25) for the 2025–30 period.[23] Ergon Energy did not propose any direct capex because direct capex relates to investment in new assets and Ergon Energy is not allowed to install new meters.

Mount Isa-Cloncurry Network

Ergon Energy maintained the approach accepted in our draft decision to forego capex related to the MI-C network. Ergon Energy noted in a response to an information request before our draft decision that it 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.[24]

22 Ergon Energy, *10.03 - Metering PTRM 2025–30*, November 2024.

23 Ergon Energy, *10.03 - Metering PTRM 2025–30*, November 2024.

24 Ergon Energy, *Information request #043 - Legacy Metering,* June 2024.

20.3.1.2 Operating expenditure

Ergon Energy substituted our draft decision for opex with a new estimate of $110.5 million ($2024–25) for the 2025–30 period, reflecting the latest information available.[25] Ergon Energy provided a revised opex model in its revised proposal that set out the unit rates for opex at different volumes of meters serviced. This will allow forecast volumes to be updated for actual volumes within the 2025–30 period to enact the true-up mechanism.

Mount Isa-Cloncurry Network

Ergon Energy's revised proposal applied our draft decision to group opex related to the MI-C network with opex related to the NEM-connected network.[26]

25 Ergon Energy, *10.03 - Metering PTRM 2025–30*, November 2024.

26 Ergon Energy, *2025–30 Revised Regulatory Proposal*, November 2024, Public, p. 117.

A Reasons for final decision

A.1 Classification and form of control

Our final decision maintains our draft decision to accept Ergon Energy’s proposal to reclassify its legacy metering services from ACS to SCS and recover costs through the revenue cap form of control. The reasons for these decisions are set out in Attachment 13 and 14.

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.

CCP30 noted that Ergon Energy had accepted the AER’s draft decision, including the reclassification from ACS to SCS. CCP30 supported this position and found it consistent with Ergon Energy’s consumer engagement outcomes, following what it considered was transparent and clear discussion.[27] Queensland Farmers’ Federation noted its support for the affordable rollout and deployment of smart meters by 2030, in line with the Queensland Energy and Jobs Plan.[28]

We also maintain our draft decision to accept Ergon Energy’s proposal to recover metering costs through a flat per customer charge to LV customers. We consider this approach to be equitable and transparent, and that it also consistent with the reasoning in our guidance we provided in response to the AEMC’s metering review.[29]

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

A.2 Annual revenue requirement

Our final decision is for a total ARR for metering services of $170.7 million ($nominal, smoothed) for Ergon Energy over the 2025–30 period.[30] This is an increase of $0.01 million ($nominal) or 0.005% from Ergon Energy's proposed total ARR of $170.7 million ($nominal, smoothed) for this period.[31] This reflects the impact on our final decision of the various building block costs listed in Table A.2.

Our final 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

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27 CCP30, Response DD and Final proposal - ERGON - Final, January 2025, p. 36.

28 QFF, *Submission to AER - Draft Decision Energy Queensland (Ergon Energy and Energex) Determination 2025-30*, January 2025, p. 10.

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

30 AER, *Final Decision - Ergon Energy - 2025–30 Distribution revenue proposal - Metering PTRM*, April 2025.

31 AER analysis; Ergon Energy, *10.03 - Metering PTRM 2025–30*, November 2024.

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.

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

Annual revenue requirement	2025–26	2026–27	2027–28	2028–29	2029–30	Total
Ergon Energy initial proposal	35.4	35.6	35.8	36.1	36.1	179.1
Draft decision	35.7	34.5	33.5	33.2	33.2	170.0
Ergon Energy revised proposal	35.6	34.4	33.5	33.1	33.1	169.8
Final decision	35.6	34.5	33.5	33.1	33.0	169.8
Final decision (smoothed)	32.3	33.2	34.1	35.0	36.0	170.7

Source: Ergon Energy, *10.04 - Metering PTRM*, January 2024; AER, *Draft decision - Ergon Energy - 2025–30 Distribution revenue proposal - Metering PTRM*, September 2024; Ergon Energy, *10.03 - Metering PTRM 2025–*30, November 2024; AER, *Final decision - Ergon Energy - 2025–30 Distribution revenue proposal - Metering PTRM*, April 2025.
Note: Amounts are inclusive of the MI-C network.

The AER's post tax revenue model (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 component and total building block costs that form the ARR and where discussion on the components that drive these costs can be found within this final decision.

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

Building block component	Total – Ergon Energy's revised proposal	Total – final decision	Section where element is discussed
Return on capital	7.8	8.0	A.4
Return of capital (regulatory depreciation)	42.0	41.7	A.5
Operating expenditure	120.0	120.0	A.7
Revenue adjustments	-	-	-
Net tax allowance	-	-	-
Revenue requirement	**169.8**	**169.8**	**A.2**

Source: Ergon Energy, *10.03 - Metering PTRM 2025*–30, November 2024; AER, *Final decision - Ergon Energy - 2025–30 Distribution revenue proposal - Metering PTRM*, April 2025.
Note: Amounts are inclusive of the MI-C network.

A.3 Regulatory asset base

Our final decision accepts Ergon Energy's asset roll forward and calculation method, with our final decision substitute values based on updated inflation inputs.

The value of the regulatory asset base (RAB) impacts Ergon Energy's revenue requirement, and the price consumers ultimately pay. Other things being equal, a higher RAB increases both the return on capital and return of capital (depreciation) components of the distribution determination. This final decision sets out in Table A.3:

- 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.5

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

Summary of asset roll forward	Ergon Energy's revised proposal	Final decision
Opening RAB on 1 July 2025	42.0	41.7
Net capex (total nominal)	-	-
Regulatory depreciation (total nominal)	-45.7	-45.3
Inflation on opening RAB (total nominal)	3.7	3.5
Forecast closing RAB on 30 June 2030	0.0	0.0

Source: Ergon Energy, *10.03 - Metering PTRM 2025*–30, November 2024; AER, *Final decision - Ergon Energy - 2025–30 Distribution revenue proposal - Metering PTRM*, April 2025.
Note: Amounts are inclusive of the MI-C network.

We use the roll forward model (RFM) to roll forward Ergon Energy's RAB from the 2020–25 period to arrive at an opening RAB value as of 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 actual 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 final 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.

A.4 Rate of Return

Our final 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 final 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 final decision including rates for return on debt, inflation, and equity raising costs.

A.5 Regulatory depreciation

Our final decision maintains our draft decision to accept the depreciation schedules proposed by Ergon Energy, with straight-line accelerated depreciation to depreciate the asset base (inclusive of MI-C network assets) within the 2025–30 period. Ergon Energy accepted our draft decision in its revised proposal.

A.6 Capital expenditure

Our final decision maintains our draft decision to accept Ergon Energy's proposal forecast capex of $0.0 million ($2024–25).[32] Ergon Energy accepted our draft decision in its revised proposal.

A.7 Operating expenditure

Our final decision is to not accept Ergon Energy's revised proposal forecast opex of $110.5 million ($2024–25).[33] Our final decision includes an alternate estimate of $111.0 million ($2024–25) reflecting a bottom-up estimate provided by Ergon Energy, as well as updates to forecast inflation.[34]

Our final decision reflects Ergon Energy's revised proposal approach to include the unit rates for opex at different volumes of meters serviced. This will allow forecast volumes to be updated for actual volumes for the purposes of the metering true-up adjustment.

Ergon Energy's approach and underlying inputs, other than those mentioned above, have not changed since our draft decision. . As a result, our assessment of the approach and inputs remains as set out in the draft decision, where we considered the forecasts efficient and prudent. Our draft decision considered the breakdown of activities and related expenditure, contracted unit rates for particular services, and Ergon Energy's procurement processes.[35] We also considered how unit rates and diseconomies of scale compared to Essential Energy, who we consider to be the most comparable network based on geographical characteristics.[36] No new proposals or considerations have emerged to change our draft decision assessment.

More information on our consideration of the bottom-up opex forecast, legacy meter replacement rates, and the true-up mechanism for opex, can be found in our draft decision.[37] Table A.4 below compares our final decision opex to Ergon Energy's revised proposal forecast opex. It also includes information on the initial proposal and draft decision opex.

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32 AER, *Final Decision - Ergon Energy - 2025–30 Distribution revenue proposal - Metering PTRM*, April 2025.

33 Ergon Energy, *10.03 - Metering PTRM 2025–30*, November 2024.

34 AER, *Final Decision - Ergon Energy - 2025–30 Distribution revenue proposal - Metering PTRM*, April 2025.

35 AER, *Draft Decision Attachment 20 - Metering Services - Ergon Energy - 2025–30 Distribution revenue proposal*, September 2024, p. 14.

36 AER, *Draft Decision Attachment 20 - Metering Services - Ergon Energy - 2025–30 Distribution revenue proposal*, September 2024, p. 14.

37 AER, *Draft Decision Attachment 20 - Metering Services - Ergon Energy - 2025–30 Distribution revenue proposal*, September 2024, pp. 14–15.

Table A.4 Revised proposal and final 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 ($million, 2024–25)	24.7	24.2	23.7	23.3	22.7	118.7
Draft decision opex ($million, 2024–25)	25.0	23.2	21.6	20.7	20.1	110.5
Ergon Energy's revised proposal opex ($million, 2024–25)	25.0	23.2	21.6	20.7	20.1	110.5
Final decision opex ($million, 2024–25)	25.0	23.2	21.7	20.8	20.3	111.0

Source: Ergon, *10.01 - Metering Opex Model 2025-30*, November 2024; Ergon Energy, *10.04 - Metering PTRM*, January 2024; AER, *Draft decision - Ergon Energy - 2025–30 Distribution revenue proposal - Metering PTRM*, September 2024; Ergon Energy, *10.03 - Metering PTRM 2025*–30, November 2024; AER, *Final decision - Ergon Energy - 2025–30 Distribution revenue proposal - Metering PTRM*, April 2025.
Note: Amounts are inclusive of the MI-C network.

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
MI-C	Mt Isa-Cloncurry
NEM	national electricity market
NER	national electricity rules
opex	operating expenditure
PTRM	post-tax revenue model
RAB	regulatory asset base
RFM	roll forward model
RRG	Regulatory Reset Group
SCS	standard control services