Draft Decision

Energex 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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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 Energex.

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, Energex 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 Energex'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 Energex's proposal (section 20.3).
- Set out the reasons for our draft decision (Appendix A).

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

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

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 national electricity market (NEM).[3] 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. Energex has forecast a legacy meter population of nearly 1,214,076 meters in 2024–25, being 51% of the legacy metering asset base when the reforms were introduced.[4]

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.[5]

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.[6]

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 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).

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3 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.

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

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

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

- 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.

20.1.2 Changes to regulatory settings

Our draft decision has 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.[7]

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).[8] 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.

20.2 Draft decision

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

- Accept Energex'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 Energex.

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7 Energex, *Attachment 19 - Legacy Metering,* January 2024, p. 10.

8 NER, cl. 6.12.3(b).

- Accept Energex's application of accelerated depreciation to the regulated asset base.
- Substitute our annual revenue requirement, which applies our substitute inputs as noted above.
- Accept Energex's reclassification to SCS and application of a revenue cap form of control.
- Accept Energex's proposed recovery of costs through a flat per customer charge to LV customers, regardless of customer, tariff, or meter type.

20.3 Energex's proposal

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

20.3.1 Metering revenue

Energex proposed a total annual revenue requirement (ARR) of $394.4 million ($nominal, smoothed) for the 2025–30 period.[9] To determine its proposed revenue requirement, Energex used the AER's standardised metering models which apply the building block approach to determine allowable revenue. Energex's proposed ARR and building blocks are set out in Table 20.1.

Table 20.1 Energex'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	12.7	10.6	8.2	5.7	3.0	40.3
Return of capital (regulatory depreciation)	37.4	39.7	42.1	44.5	47.1	210.7
Operating expenditure	27.6	27.7	27.7	27.8	27.5	138.3
Revenue adjustments	-	-	-	-	-	-
Net tax allowance	-	-	-	-	-	-
ARR (unsmoothed)	**77.7**	**77.9**	**78.0**	**78.1**	**77.6**	**389.3**
ARR (smoothed)	**63.0**	**70.1**	**78.0**	**86.8**	**96.5**	**394.4**

Source: Energex, *10.04 - Metering PTRM 2025–30*, January 2024.

20.3.1.1 Capital expenditure

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

20.3.1.2 Operating expenditure

Energex's proposed opex of $138.3 million ($nominal) for the 2025–30 period includes the costs of performing meter maintenance as well as routine meter reading and testing.[10]

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9 Energex, *10.04 - Metering PTRM 2025–30*, January 2024.

10 Energex, *10.04 - Metering PTRM 2025–30*, January 2024.

Energex 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.

Energex’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.[11] 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

Energex forecast to retire 74% of its legacy meters over the 2025–30 period (compared to remaining legacy meters in 2024–25), leaving 313,949 legacy meters in place in 2029–30.[12]

Energex has proposed to replace 11% to 19% of legacy meters each year during the period.[13] Based on evidence from the Victorian smart meter rollout, Energex anticipates 15% of sites will not be upgraded by the end of June 2030.[14]

20.3.1.3 Regulatory depreciation

Energex proposed straight line accelerated depreciation for the opening regulatory asset base (RAB) in the 2025–30 period.[15] Energex 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.[16] The asset base is proposed to be fully depreciated by the end of the 2025–30 period.

20.3.2 Pricing

Energex proposed to calculate its revenue cap for legacy metering services using the building blocks from the post tax revenue model (PTRM). Energex proposed to recover the relevant revenue cap from LV customers through a flat per customer charge, as per our guidance and 2024–29 determinations.[17]

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11 Energex, *Information Request #043 – Legacy metering*, 8 July 2024.

12 Energex, *10.02 - Metering expenditure model 2025–30*, January 2024.

13 AER analysis; Energex, *10.02 - Metering expenditure model 2025–30*, January 2024.

14 Energex, *2025–30 Regulatory proposal*, January 2024, p. 183.

15 Energex, *2025–30 Regulatory proposal*, January 2024, p. 184.

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

17 Energex, *10.05 - Metering pricing model 2025–30*, January 2024.

A Reasons for draft decision

A.1 Classification and form of control

Our draft decision accepts Energex'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 Energex 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.[18] As such, we accept Energex's proposal to depart from the F&A by reclassifying metering as SCS. Consistent with the reasoning in our guidance,[19] 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.

Energex has broad stakeholder support for its approach. The Reset Reference Group (RRG), Origin, 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.[20] The RRG also noted that the proposed charging arrangement supports the objectives of the smart meter rollout,[21] and that customers supported the proposed changes during pre-lodgement engagement.[22]

We also accept Energex'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.[23]

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

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

20 Energy Queensland Regulatory Reset Group, *RRG Independent Engagement Report Energex Final*, June 2024, p. 26; Origin, *Submission to the Energex, Ergon Energy and SA Power Networks regulatory proposals*, May 2024, pp. 3-4; Master Electricians Australia, *Submission - 2025–30 Electricity Determination – Energex*, May 2024, p. 4; CCP30, *Response EQL Issues Paper and proposal*, May 2024, p. 39.

21 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.

22 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. 67.

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

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

A.2 Annual revenue requirement

Our draft decision is for a total ARR of $377.2 million ($nominal, smoothed) for Energex over the 2025–30 period.[24] This is a decrease of $17.2 million ($nominal) or 4.4% from Energex's proposed total ARR of $394.4 million ($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.

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

Annual revenue requirement	2025–26	2026–27	2027–28	2028–29	2029–30	Total
Energex initial proposal	77.7	77.9	78.0	78.1	77.6	389.3
Draft decision	75.8	76.6	76.0	74.7	72.2	375.4
Draft decision (smoothed)	71.3	73.3	75.4	77.5	79.7	377.2

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

We assessed Energex'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.

24 AER, *Draft decision - Energex distribution determination 2025–30 - Metering PTRM*, September 2024.

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

Building block component	Total – initial proposal	Total – draft decision	Section where element is discussed
Return on capital	40.3	39.9	A.4
Return of capital (regulatory depreciation)	210.7	209.9	A.5
Operating expenditure	138.3	125.6	A.7
Revenue adjustments	-	-	-
Net tax allowance	-	-	-
Revenue requirement	389.3	**375.4**	**A.2**

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

A.3 Regulatory asset base

Our draft decision accepts Energex'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 Energex'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.5

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

Summary of asset roll forward	Initial proposal	Draft decision
Opening RAB	210.7	209.9
Net capex (total nominal)	-	-
Regulatory depreciation (total nominal)	-229.1	-228.5
Inflation on opening RAB (total nominal)	18.4	18.6
Forecast closing RAB	0.0	0.0

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

We use the RFM to roll forward Energex's RAB over 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 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.

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 Energex, 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 Energex, we make determinations on the indexation of the RAB and depreciation building blocks for Energex'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.[25]

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

We explored the possibility of not accepting the proposal to accelerate depreciation to mitigate the overall price impact for Energex customers. Energex demonstrated that reductions from not accelerating depreciation would be largely offset by additional tax

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25 NER, cl. 6.5.5(a).

payable amounts that would result from the metering assets continuing their standard lives.[26] The resulting price impact from accepting the proposed accelerated depreciation is on average $3 per year over the 2025–30 period. We consider this reasoning acceptable.

The RRG supported this approach given the small bill impact over the 2025–30 period.[27]

A.6 Capital expenditure

Our draft decision is to accept Energex's proposed zero capex.[28]

A.7 Operating expenditure

Our draft decision is to not accept Energex's proposal forecast opex of $138.3 million ($nominal). Our draft decision includes an alternate estimate of $125.6 million ($nominal) reflecting a bottom-up estimate provided by Energex, as well as updates to labour cost escalation and inflation.[29]

Energex'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, Energex provided a bottom-up forecast opex that was used to determine trend factors for the top-down approach.[30] We have used the 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 Energex'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)	989,044	764,012	583,987	448,968	313,949	
Energex's proposed opex ($million, nominal)	27.6	27.7	27.8	27.8	27.5	138.3
Draft decision opex ($million, nominal)	26.0	26.7	26.0	24.7	22.3	125.6

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

26 Energex, *Information Request #034 – Legacy metering*, 14 June 2024.

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

28 Energex, *10.04 Metering PTRM*, January 2024.

29 AER, *Final decision - Energex distribution determination 2025–30 - Metering PTRM*, September 2024.

30 Energex, *Information Request #043 – Legacy metering*, 8 July 2024.

Base-step-trend opex forecast

We raised concerns regarding the rates of change applied in the trend component of Energex's proposal. [31] 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 Energex's proposal were the same for both the Energex and Ergon Energy networks, despite being quite different in geographical characteristics. We requested further information from Energex to support these factors.

Energex 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.[32] Energex 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 Energex's proposal in our draft decision, rather than assess the top-down approach Energex provided in its proposal.

Bottom-up opex forecast

In its bottom-up opex forecast, Energex 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.[33] Energex also provided context on their procurement processes and other relevant considerations affecting its bottom-up opex forecast.[34]

Based on our analysis and the supporting information, we consider these forecasts are prudent and efficient. Energex's opex per customer is similar to that approved for Ausgrid. We consider Ausgrid to be the most comparable network for Energex 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.

Energex's proposal is to replace 11% to 19% of legacy meters each year during the period.[35] Energex anticipated there will be 15% of sites exempted and not upgraded by the end of June 2030.[36] This is based on the Victorian smart meter roll out. We consider Energex'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

31 AER, *Information Request #043 – Legacy metering*, 24 June 2024.

32 Energex, *Information Request #043 – Legacy metering*, 8 July 2024.

33 Energex, *Information Request #053 – Legacy metering*, 15 August 2024.

34 Energex, *Information Request #053 – Legacy metering*, 15 August 2024.

35 AER analysis; Energex, *10.02 - Metering expenditure model 2025–30*, January 2024.

36 Energex, *2025–30 Regulatory proposal*, January 2024, p. 183.

meters from doing so.[37] We consider that the AEMC's metering review has appropriately addressed incentives for the rollout of smart meters.

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, Energex 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.

37 Master Electricians Australia, *Submission - 2025–30 Electricity Determination – Energex*, May 2024, p. 4.

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
F&A	Framework and approach paper
LMRP	legacy meter retirement plan
LV	low voltage
MEA	Master Electricians Australia
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