# Draft Decision

## Ergon Energy Electricity Distribution Determination 2025 to 2030

(1 July 2025 to 30 June 2030)

## Overview

September 2024

AUSTRALIAN ENERGY REGULATOR

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**Amendment record**

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# Invitation for submissions

Ergon Energy has the opportunity to submit a revised proposal in response to this draft decision by **26 November 2024.**

Interested stakeholders are invited to make a submission on both our draft decision and Ergon Energy's revised proposal (once submitted) by Friday, **17 January 2025**.

Submissions should be sent to: energyqueensland2025@aer.gov.au and addressed to Gavin Fox, General Manager. Alternatively, you can mail submissions to GPO Box 3131, Canberra ACT 2601.

Submissions should be in Microsoft Word or another text readable document format.

We prefer that all submissions be publicly available to facilitate an informed and transparent consultative process. We will treat submissions as public documents unless otherwise requested.

Parties wishing to submit confidential information should:

1. Clearly identify the information that is the subject of the confidential claim.
2. Provide a non-confidential version of the submission in a form suitable for publication.

All non-confidential submissions will be published on our website.

## Predetermination conference

Consumer engagement is a valuable input to our determination. We encourage all interested stakeholders to join us, the Ergon Energy predetermination conference at an online public forum on **10 October 2024**. Details of how to register for this forum are available on our website and through Eventbrite.

# List of attachments

This attachment forms part of the Australian Energy Regulator's (AER's) draft 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 draft decision.

The draft decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

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Attachment 10 – Service target performance incentive scheme

Attachment 11 – Demand management incentive scheme and demand management innovation allowance mechanism

Attachment 13 – Classification of services

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Attachment 16 – Alternative control services

Attachment 17 – Negotiated services framework and criteria

Attachment 18 – Connection policy

Attachment 19 – Tariff structure statement

Attachment 20 – Metering services

# Executive summary

The Australian Energy Regulator (AER) exists to ensure energy consumers are better off, now and in the future. Consumers are at the heart of our work, and we focus on ensuring a secure, reliable, and affordable energy future for Australia as it transitions to net zero emissions (the transition).

A regulated network business must periodically apply to us to determine the maximum allowed revenue it can recover from consumers for using its network. On 31 January 2024, we received revenue proposals from SA Power Networks, Ergon Energy, Energex and Directlink for the period 1 July 2025 to 30 June 2030 (2025–30 period).

It is our role to ensure that consumers pay no more than is necessary for an energy system that delivers safe, reliable, secure energy that contributes to the reduction of greenhouse gas emissions.

This draft decision relates to Ergon Energy, a subsidiary of Energy Queensland.

## Efficient investment that delivers a safe and reliable network that meets consumer needs

The past decade has seen a phase of relatively contained capital and operating expenditure while maintaining service quality. However, recent regulatory proposals, including Ergon Energy's 2025–30 proposal, have included substantial increases in forecast expenditure citing the need to adapt to an evolving energy system and to improve or maintain reliability.

We acknowledge there are factors requiring distribution network service providers (DNSPs) to invest in their networks, but this needs to be managed carefully, with a view to protecting the long-term interests of consumers. This underscores the importance of networks developing solid business cases that seek to find the most efficient investment options to meet demand and comply with state safety and technical standard obligations.

Safety is enshrined in the National Electricity Objective (NEO) and a key component of our decision making. State and territory legislation governs the safe supply of electricity. We expect DNSPs to submit proposals that meet their safety obligations in a way that is prudent and efficient. Our draft decision for Ergon Energy underscores the need for further work to ensure Ergon Energy's capital expenditure (capex) proposals meet these objectives.

Ergon Energy's proposal comes at a time when asset utilisation across the National Electricity Market (NEM) is low by historical standards and network reliability near the highest it has been. We encourage DNSPs and stakeholders to seek ways to improve asset utilisation to meet the challenges of the energy transition and to manage growth in the network over the long term. Accordingly, our draft decisions reflect our support for DNSPs to efficiently integrate consumer energy resources (CER) by improving capacity of their existing systems, modernising IT systems and implementing new tariff options.

The regulatory proposals we have received also respond to the ongoing challenge of maintaining service reliability and improving network and system resilience to disruptive events. Floods, bushfires and cyber risks have all affected our distribution and transmission networks across the NEM in recent years. Our draft decisions support cost effective solutions to manage these risks for consumers.

We are supportive of tariff reform aimed at reducing the amount of network investment required to ensure sufficient network capacity and stability during peak demand and export periods. Nevertheless, we do not accept all elements of Ergon Energy's tariff proposal. Our draft decisions ensures that retailers are able to offer retail tariffs that suit their customers, including through the provision of flat retail tariffs.

Consumer needs should be a key focus of the DNSPs' regulatory proposals. To assist, we introduced the Better Resets Handbook (the Handbook)[1], to further guide businesses to engage and design proposals that meet consumer needs through the energy transition.

Overall, Ergon Energy's engagement fell short of what is expected under the Handbook and of the standard that we have seen from other recent electricity distribution resets. Ergon Energy's engagement started late and was narrow in its scope as a result. The absence of meaningful and comprehensive consultation on future investment decisions also meant that the issue of affordability was unable to be addressed with consumers.

We encourage a more consultative process on key elements of our draft decision to inform the revised proposal.

## Our assessment of Ergon Energy's proposal

This draft decision allows Ergon Energy to recover $8,365.9 million ($ nominal, smoothed) in main standard control services (SCS) revenue from its customers for the 2025–30 period. This is $156.4 million less than the $8,522.3 million that Ergon Energy proposed. Our draft decision for Ergon Energy is not reflected directly in consumer bills given the Queensland governments uniform tariff policy, which sets retail prices in Ergon Energy's distribution area in line with Energex prices. We estimate that our draft decision for Energex would increase bills by $39 or 1.8% per annum over the 2025–30 period.

Our draft decision revenue is $2,357.1 million more than Ergon Energy's allowed revenue in the 2020–25 period in nominal terms.[2] We estimate that approximately 56% of the increase from the 2020–25 period is driven by market factors including higher inflation and interest rates. The other 44% of the increase is driven by expenditure and other controllable factors.

We recognise that Ergon Energy is responding to challenges of increased uptake of CER and increasingly harsh climate conditions.[3] We have accepted aspects of the proposal that meet these challenges in an efficient and prudent manner. This includes CER capex, the bushfires and floods program and cyber-related capex.

Our draft decision also accepts Ergon Energy's operating expenditure (opex) proposal for main standard control services, which is forecast to moderate over the next period due to efficiency and productivity adjustments and only one step change.

The key issue in setting Ergon Energy's required revenue for the next 5 years is related to its replacement expenditure (repex) overspend over 2018–23 and determining how much is rolled into the regulatory asset base (RAB). Our draft decision recognises that Ergon Energy had a genuine need to make capital investments beyond the AER's forecast over the current period in response to an emerging issue with pole defects in its network. However, based on

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1 AER, Better Resets Handbook – towards consumer-centric network proposals, December 2021.

2 Adjusting for the impact of inflation, our draft decision revenue is 13.2% higher than Ergon Energy's allowed revenue for the 2020–25 period.

3 Ergon Energy, *2025-30 Regulatory Proposal*, January 2024, p. 28.

the information before us, we consider the magnitude of overspend was not in line with prudent and efficient decision making. Our ex-post review is further discussed below.

Our draft decision does not accept Ergon Energy's forecast capex for the 2025–30 period. Our forecast of $4,188.1 million is 26.6% lower than Ergon's forecast of $5,704.8 million ($2024–25) for the 2025–30 period. Our draft decision on Ergon Energy's forecast capex is a placeholder subject to further supporting information being provided, largely around our concerns regarding aspects of repex and augmentation expenditure (augex).

We found that most of Ergon Energy's repex forecast was based on a continuation of its historical capex, which our ex-post review found not be prudent and efficient. Ergon Energy's proposed augex programs, particularly for grid communications, protection and control and the distribution feeder augmentation project require further evidence to show that these investments reflect prudent and efficient business practices.

While our draft decision does not accept Ergon Energy's tariff proposal, we consider Ergon Energy is making progress on network tariff reform, responding to feedback and supporting the energy transition. This includes introducing solar soak windows and streamlining its suite of tariffs. Two key elements of our draft decision are to require the default tariff assignments for small customers to have a time-of-use structure rather than demand-based structure, and to offer a time-of-use tariff for business customers with peaky demand but low consumption. We consider these changes better comply with the NER pricing principles (for the default tariffs) and better contribute to the achievement of the NEO (for the time-of-use business tariff), particularly the achievement of jurisdictional targets for emissions reduction.

Our draft decision accepts Ergon Energy's proposal to reclassify metering services from alternative control services to standard control services and to socialise these costs across low voltage customers. This is due to the outcomes of the Australian Energy Market Commission's (AEMC's) metering review which is seeking to replace historical accumulation meters with smart meters by 2030. Ergon Energy's proposal is consistent with our recent decisions which focussed on implementing regulatory settings that best protect consumers, particularly vulnerable consumers, from price spikes during the transition. Our draft decision allows Ergon Energy to recover $170.9 million from its customers for the provision of metering services.

In this Overview and the accompanying detailed attachments, we have set out the assessment approaches applied, and enquiries made as part of our review, which have enabled us to arrive at this draft decision.

This draft decision is the mid-point in our assessment of Ergon Energy's proposal. Ergon Energy now has the opportunity to respond in a revised proposal that incorporates the substance of the changes required by, and addresses matters raised in, this draft decision.

## Ex-post review into Ergon Energy's capex overspend

Our draft decision would allow an overspend of $598.8 million in 2018–23 to be included into the opening RAB at 1 July 2025, a reduction of 50.0% compared to the total overspend of $1,195.0 million. We consider our draft decision to be a placeholder based on the information before us. During our assessment we found a lack of supporting material to demonstrate prudent and efficient expenditure decisions, including information gaps, and poor-quality data with material data discrepancies. We encourage Ergon Energy to engage with us and to provide us with the relevant supporting information in the lead up to, and as part of its revised proposal.

Prior to assessing Ergon Energy's forecast capex program for the next regulatory period (2025–30), the AER is required by law to determine how much of the capex overspend in the current period should be rolled into the opening RAB for the next 5 years.

We did this by conducting an ex-post review to determine whether Ergon Energy's expenditure was prudent and efficient. The ex-post review is an important part of the regulatory framework to protect consumers from paying for excessive investment in the network. The size of the regulatory asset base has a significant impact on the bills consumers pay because businesses are entitled to recover the cost of their past investment via a depreciation schedule and are entitled to a regulated return on the overall RAB.

Ergon Energy's real RAB increased 11.9% in the current 2020–25 period driven by its overspend. All else being equal, this has resulted in a higher RAB over the 2025–30 period. In comparison, Energex's RAB remains relatively flat over the same period.

Our ex-post review, which is at Attachment 5, found a genuine need for Ergon Energy to increase spending beyond our final decision forecasts to bring an increasing trend in pole defects under control. However, our review also found that Ergon Energy's response to address the pole defects was not reflective of prudent and efficient decision making. Ergon Energy's governance and asset management practices did not involve root cause analysis to understand the underlying cause of the defects, and business cases and cost-benefit analysis to consider the most appropriate option for addressing the need.

In particular, we consider that Ergon Energy's response by adopting Energex's pole management practices and standards has resulted in higher pole replacement than is efficient. Energex, as an urban network, has an inherently different risk profile compared to Ergon Energy's predominately rural network. This is because, when compared to Ergon Energy's network, Energex's higher customer density network consists of higher demand per line, which results in more customers losing supply during asset failures. Safety risks are also higher in an urban network when compared to a predominantly rural network due to the higher probability of public exposure from assets being in closer proximity to urban centres. Therefore, applying Energex's practices and standards has led to unnecessarily high costs to maintain asset performance.

We found that Ergon Energy's opportunistic replacement of assets related to its pole replacement program, which makes up to 44.2% of the total overspend, was considerably more than is consistent compared with good industry practice.[4] Early replacement was made to larger assets like transformers and switchgears with a lack of evidence to support the prudency and efficiency of these investments. We found: negative cost benefit from Ergon Energy's own analysis in relation to some opportunistic replacement; no emerging safety risk associated with those assets; and replacement in many cases was not consistent with Ergon Energy's own business rules.

Our ex-post review also found that Ergon Energy's response to address breaches of its clearance limits was not prudent and efficient. Ergon Energy often selected the higher cost option of replacement to address defects compared to the lower cost industry accepted practice of re-tensioning (or a combination of re-tensioning and staking).

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4 Opportunistic replacement is a practice where other assets are replaced at the same time as targeted assets. These other assets are at the same location as targeted assets but are usually of lesser value and at a lower level of replacement priority.

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# 1 Our draft decision

Our draft decision allows Ergon Energy to recover a total revenue of $8,536.8 million ($ nominal, smoothed) from its consumers from 1 July 2025 to 30 June 2030 which comprises:

- $8,365.9 million in main standard control services (SCS) revenue
- $170.9 million in metering revenue[5]

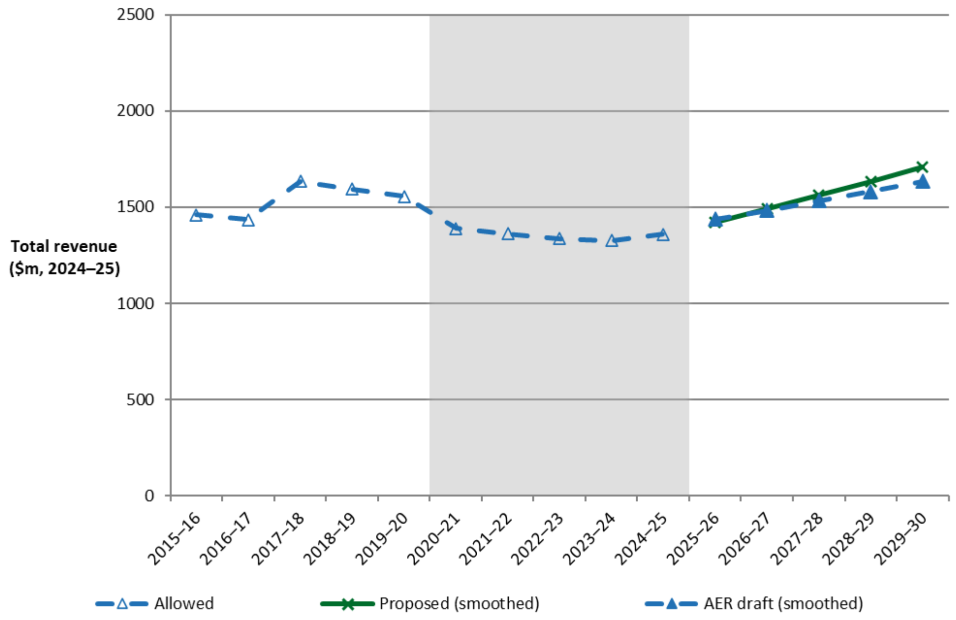
Our draft decision total revenue is $2,357.1 million more than Ergon Energy's allowed revenue in the 2020–25 period in nominal terms.[6] In the sections below we briefly outline what is driving Ergon Energy's main SCS revenue, and the key differences between our draft decision revenue of $8,365.9 million and the $8,522.3 million in Ergon Energy's proposal.[7]

## 1.1 What is driving revenue?

Revenue is driven by changes in real costs and inflation. To compare revenue from one period to the next on a like-for-like basis, we use 'real' values based on a common year (2024–25) that have been adjusted for the impact of inflation.

In real terms, this draft decision would allow Ergon Energy to recover $7,669.7 million ($2024–25, smoothed) over the 2025–30 period. This is 13.2% higher than our decision for the 2020–25 period. Changes in Ergon Energy's revenue over time are shown in Figure 1.

**Figure 1 Changes in regulated revenue over time ($ million, 2024–25)**




Source: AER analysis.

5 This is $8.8 million less than the $179.7 million that Ergon Energy proposed for metering.

6 Adjusting for the impact of inflation, our draft decision revenue is 13.2% higher than Ergon Energy's allowed revenue for the 2020–25 period.

7 This overview separates main SCS revenue from metering SCS revenue (see Attachment 20) for ease of comparison with previous regulatory periods. Moreover, most metering costs are temporary.

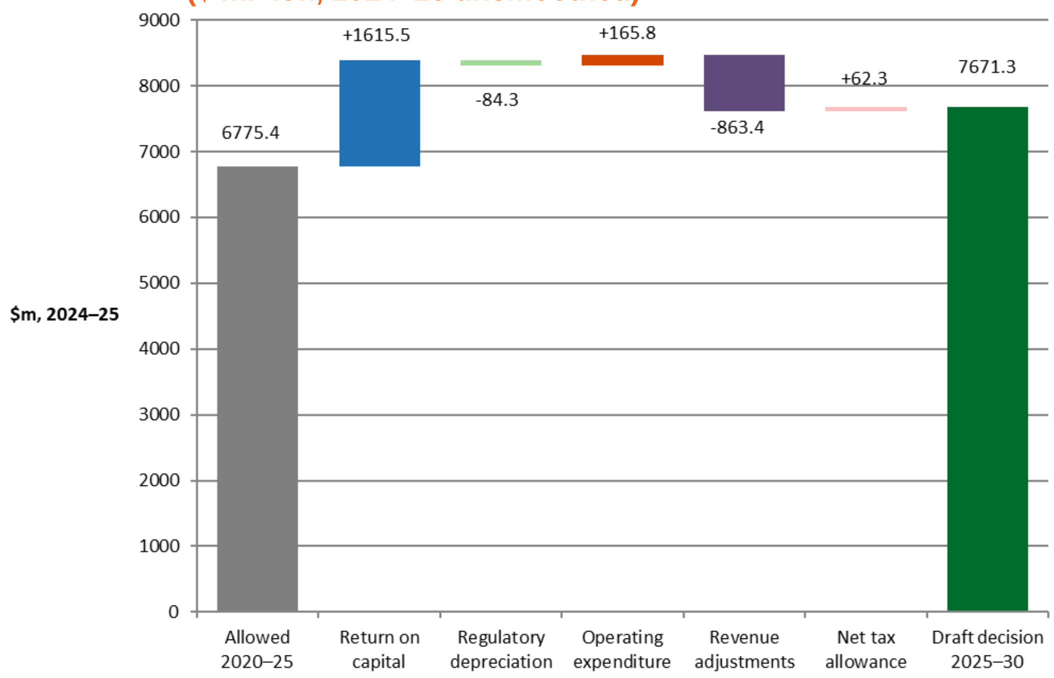
Figure 2 highlights the key drivers of the change in real terms between the revenue approved for Ergon Energy for the 2020–25 period and in this draft decision for the 2025–30 period. It shows that our draft decision provides for increases in the building blocks for:

- return on capital, which is based on the opening RAB, forecast capex and rate of return. This is $1,615.5 million (51.5%) higher than the 2020–25 period, driven by:
  - a higher rate of return being applied in the 2025–30 period, in accordance with the 2022 *Rate of Return Instrument.*
  - RAB growth in the 2020–25 period from capex included in the RAB which was higher than was forecast in that period, and higher actual inflation in that period.
  - higher forecast capex in the 2025–30 period.
- opex, which is $165.8 million (7.5%) higher than the opex forecast we approved in the 2020–25 period, driven primarily by the trend forecast and the network visibility step change.
- net tax amount, which is $62.3 million higher than the 2020–25 period, primarily due to a higher return on equity (which increases taxable income) determined in this draft decision compared to the 2020–25 period.

Figure 2 also shows that our draft decision provides for decreases in the building blocks for:

- return of capital (regulatory depreciation), which is $84.3 million (6.8%) lower than the 2020–25 period, driven primarily by a higher indexation of the RAB.
- revenue adjustments, which are $863.4 million lower than the 2020–25 period, mainly due to the large negative Efficiency Benefit Sharing Scheme (EBSS) and Capital Expenditures Sharing Scheme (CESS) outcomes applied in this draft decision.

**Figure 2 Changes in total revenue between 2020–25 period and 2025–30 period ($ million, 2024–25 unsmoothed)**

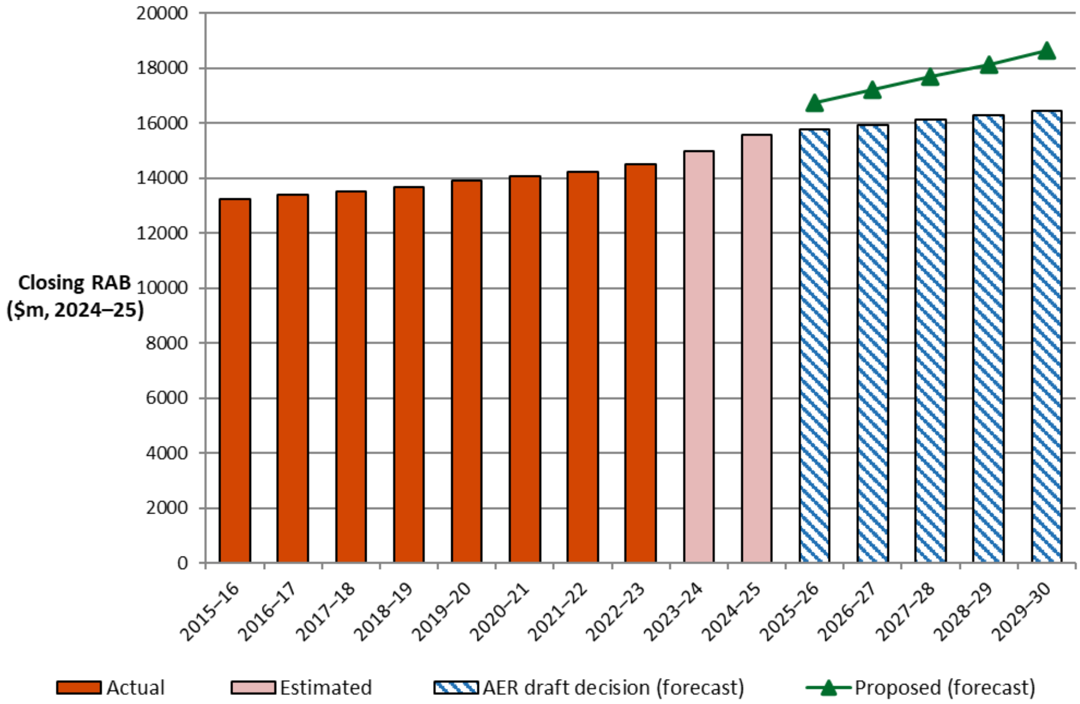



Source: AER analysis

Note: This comparison is based on converting nominal forecast amounts to real dollar terms using lagged consumer price index (CPI).

Figure 3 shows the value of Ergon Energy's RAB over time in real terms. After a RAB increase of 11.9% over the 2020–25 period, our draft decision is expected to result in a forecast RAB increase of $890.8 million (5.7%) over the 2025–30 period. This growth in the RAB is driven by forecast capex.

**Figure 3 Ergon Energy's RAB value over time ($ million, 2024–25)**




Source: AER analysis.

## 1.2 Key differences between our draft decision and Ergon Energy's proposal

Our draft decision accepts some elements of Ergon Energy's proposal including its forecast opex for main standard control services. However, we have made amendments to core components of Ergon Energy's proposal which have led to a lower revenue outcome. For the 2025–30 period, the main areas of difference between our draft decision and Ergon Energy's proposal relate to our:

- ex-post review of actual capex for 2018–23, which resulted in us excluding some of Ergon Energy's overspend and therefore lowering the opening RAB.
- reduced capex forecasts, primarily driven by reductions in repex and augex.

We have also made updates in our draft decision to reflect movements in some market variables, such as expected inflation and rate of return, which have impacted revenue outcomes for certain building blocks.

Overall, our draft decision provides a lower return on capital amount, driven by our lower opening RAB, forecast capex and rate of return.[8] This reduction is partially offset by:

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8 Average rate of return over the 2025–30 period.

- reduced negative revenue adjustments driven by lower CESS penalties, since we are reducing actual capex for 2018–23 as a result of our ex-post review
- a higher estimated cost of corporate income tax amount, driven by lower tax depreciation from our reduced opening tax asset base (TAB) and reduced forecast capex. The lower tax depreciation increases the cost of corporate income tax as it is a component of tax expense.

The regulatory depreciation amount is largely unchanged. The amendments to forecast and actual capex have the effect of reducing straight-line depreciation, but this has been offset by the lower indexation of the RAB as a result of our reductions to actual and forecast capex.

Ergon Energy also proposed to reclassify the legacy metering services following the AEMC's final decision of the Metering review.[9] As a result, Ergon Energy proposed legacy metering costs move to standard control services.

## 1.3 Expected impact of our draft decision on electricity bills

Our bill impact calculations for Ergon Energy small customers are based on our draft decision for Energex. Retail electricity prices in Ergon Energy's distribution area are determined under the Queensland Government's uniform tariff policy. The policy sets retail electricity prices in Ergon Energy's distribution area in line with those in Energex's area.[10] Ergon Energy recovers its regulated revenue through distribution charges, set annually by reference to the tariff structure statement and pricing formulae approved as part of this decision. Figure 4 shows the modelled impact of distribution charges under this draft decision and the proposal in real terms.

The draft decision is estimated to increase Ergon Energy's average distribution charges by around 18.6% in real terms by 2029–30 compared to 2024–25, or an average real increase of 3.5% per annum.[11] This estimate will be subject to ongoing revenue adjustments and changes in consumer energy consumption.

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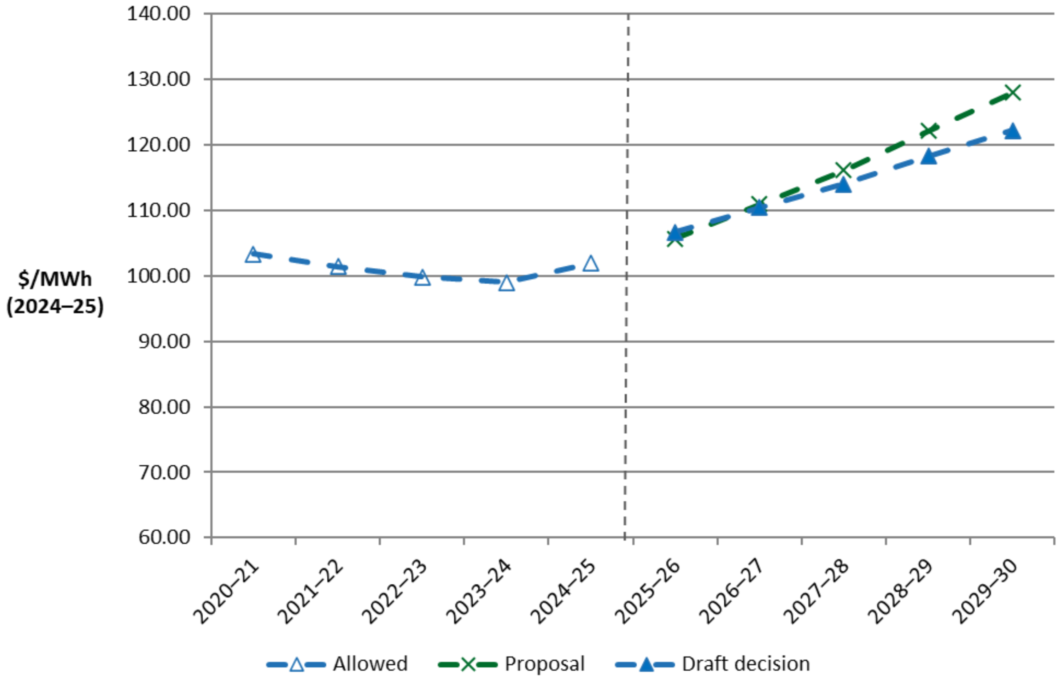
9 Ergon Energy, *2025-30 Regulatory Proposal*, February 2024, pp. 181–182.

10 Queensland Competition Authority, *Regulated electricity prices for regional Queensland 2024–25 Final determination*, pp. 10-11.

11 The average increase to indicative network charges of 3.5% ($2024–25) per annum reflects two components: 1) The draft decision smoothed revenue average increase of 3.3% per annum ($2024–25); and 2) The forecast energy delivered in Ergon Energy's distribution network area which is expected to decrease on average by 0.2% per annum.

**Figure 4 Change in indicative distribution charges for 2020–25 to 2025–30 ($2024–25, $/MWh)**




Source: AER analysis.

Note: The chart's y-axis is set to start from a non-zero value to magnify differences between price paths, providing a more detailed view of the variations.

## Potential bill impact

As retail electricity prices in Ergon Energy's distribution area are determined under the uniform tariff policy, we adopt Energex's bill impacts for this section.

Ergon Energy's distribution charges make up around 27.1% of its residential customers' electricity bills and 26.5% of its small business customers' electricity bills. Other components of the electricity supply chain—the cost of purchasing energy from the wholesale market, transmission network charges, environmental schemes and the costs and margins applied by electricity retailers in determining the prices they will charge consumers for supply—also contribute to the prices ultimately paid by consumers.[12] These sit outside the decision we are making here but will also continue to change throughout the period.

This is a draft decision, and final decision outcomes are likely to change. In nominal terms, which include the effect of expected inflation, the impact of this draft decision would be an increase to the distribution component of customers' electricity bills. For illustrative purposes only, the modelled impact of our draft decision on the average annual electricity bill for a customer in Ergon Energy's network area, as it is today, would be:[13]

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12 AEMC, *Data Portal*, *Trends in Queensland supply chain components 2023/24*.

13 Our estimated bill impact is based on the typical annual electricity usage of 4,600 kWh and 10,000 kWh for residential and small business customers in Energex's network area, respectively; AER, *Revised final determination – Default Market Offer Prices 2024–25*, June 2024, p. 6.

- a nominal increase of $197 (9.6%) by 2029–30, or an average of $39 per annum for a residential customer
- a nominal increase of $397 (9.3%) by 2029–30, or an average of $79 per annum for a small business customer.

Over the 2025–30 period there are several additional mechanisms under the NER that may operate to increase or decrease those charges. These may include cost pass through events and additional cost pass through events. The triggers we have set out for these projects resulting from pass through events in this decision will, if met, allow Ergon Energy to apply for additional revenue for these projects throughout the period, at which point proposed costs will be subject to further consultation and assessment.

## 1.4 Ergon Energy's consumer engagement

Consumer engagement during the regulatory process is an important way to provide us with supporting evidence that proposals have been aligned with consumer interests and expectations. We introduced guidance on our expectations for consumer engagement to network businesses in December 2021.[14]

It is the responsibility of network businesses to ensure that consumer views are considered and represented in their regulatory proposal. Often consensus is not possible, in which case the views of the differing groups and how the network sought to make its decision should be reflected in its proposal. Our role is to consider the consumer engagement process and the stakeholder submissions when making our various draft decisions.

### 1.4.1 Ergon Energy's engagement on its proposal

We observed elements of Ergon Energy's consumer engagement, along with our Consumer Challenge Panel, subpanel 30 (CCP30), and Ergon Energy's Reset Reference Group (RRG). Overall, Ergon Energy's engagement fell short of what is expected under the Handbook and of the standard that we have seen from other engagement programs from recent electricity distribution resets.

Ergon Energy's engagement started late and was narrow in its scope as a result. We acknowledge that for some areas, such as public lighting, Ergon Energy engaged well, put forward options and let stakeholders influence its proposal. Ergon Energy targeted its consultation with end customers (facilitated by Mosaic Lab) to focus on incentive schemes, tariff structures and small parts of capex (some ICT, property, EVs, CER enablement).

However, Ergon Energy missed an opportunity to broaden its consultative engagement to key areas of its proposal that would have had a more meaningful impact on consumers overall. This is particularly with respect to Ergon Energy's capex forecasts and the implications of the significant overspend on repex. Discussions on capex were mainly confined to the RRG and was limited to informing stakeholders.

The issue of affordability is a key theme of Ergon Energy's proposal that was raised by consumers. However, the absence meaningful and comprehensive consultation on future

[14] AER, *Better Resets Handbook – towards consumer-centric network proposals*, December 2021.

investment decisions with end consumers and the RRG has meant that the issue of affordability was unable to be addressed.

We observe that Ergon Energy discussed plans to engage on the draft decision with its RRG. We encourage and support a consultative process on key elements of our draft decision to inform their revised proposal.

### 1.4.2 What we've heard from stakeholders

In our Issues Paper, we asked stakeholders to consider whether Ergon Energy chose the right topics to engage with consumers on, and the level of influence that consumers have had in the engagement process. We also asked consumers whether Ergon Energy's proposal adequately reflects consumers' affordability concerns.

We received 17 submissions on Ergon Energy's proposal submitted on 31 January 2024, and our issues paper published 26 March 2024. The CCP30 and RRG reiterated their advice throughout the pre-engagement process that the scope of consumer engagement was too narrow and that there should have been an opportunity for consumers to influence parts of the proposal that have a significant impact on consumer bills.

> *The depth and breadth of engagement on other topics was limited due to time constraints. Specifically, this meant that beyond publication of Draft Plans, there was very little engagement on the capex and opex building blocks with consumers generally. Engagement with the RRG had a wider scope but that was still substantially less than is expected under the Better Resets Handbook or what RRG members have seen on other recent electricity distribution resets.*[15]

The CCP30 and RRG noted that affordability was a key concern throughout the pre-lodgement engagement process. Both CCP30 and RRG noted the missed opportunity of reflecting consumer views in the proposal.

> *[t]he commitment to feed customer input back into much of the key aspects of the proposals was not strong, particularly around affordability. Customers were canvassed more on issue of timing than the need of the investment itself. Key information was framed as 'inform', with investments presented as being 'already locked in.' Detailed deep dives were held after the regulatory proposal proposed expenditure was largely finalised and signed off.*[16]

Stakeholders also provided a range of feedback that included support for CER, support for community batteries, and concern over some tariff structures including storage tariffs. Other stakeholders had provided views on the level of capex including augmentation expenditure. The AER has considered stakeholder feedback in determining its various draft decisions – our consideration of stakeholder feedback on these range of issues are reflected in the relevant attachments.

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[15] EQL RRG, *Submission – [Energex & Ergon 2025-30 Electricity Determination](#)*, May 2024, p. 3.

[16] CCP30, *[Response to EQL proposal and AER Issues Paper](#)*, May 2024, p. 3.

# 2 Key components of our draft decision

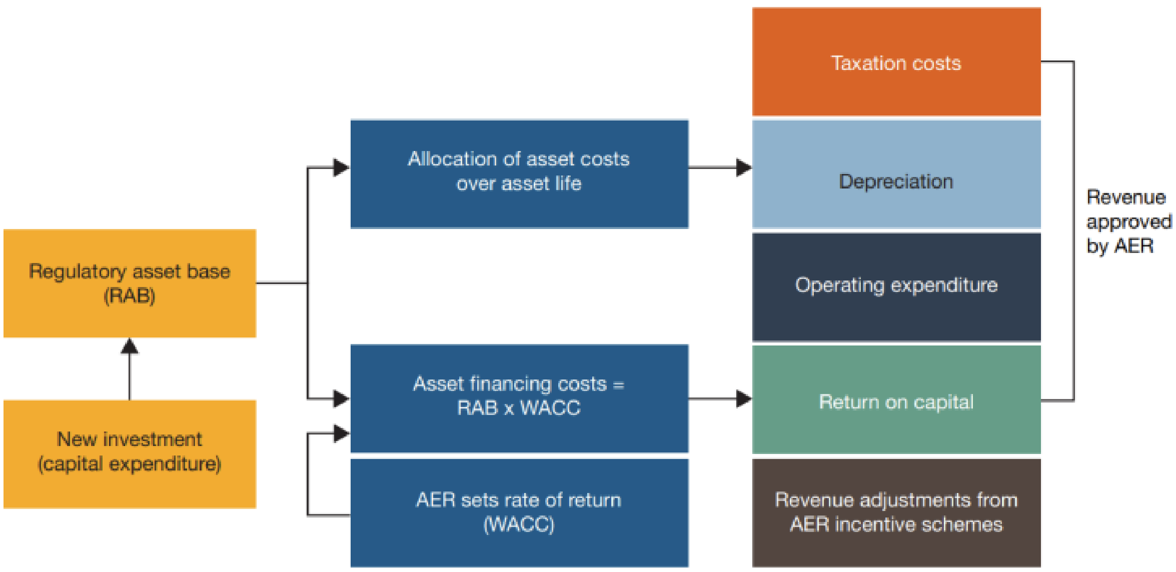
### Building block approach

The foundation of our regulatory approach is a benchmark incentive framework to setting maximum revenues: once regulated revenues are set for a 5-year period, a network that keeps its actual costs below the regulatory forecast of costs retains part of the benefit. This provides an incentive for service providers to become more efficient over time. It delivers benefits to consumers as efficient costs are revealed and drive lower cost benchmarks in subsequent regulatory periods. By only allowing efficient costs in our approved revenues, we promote achievement of the NEO and ensure consumers pay no more than necessary for the safe and reliable delivery of electricity.

Ergon Energy's proposed revenue reflects its forecast of the efficient cost of providing distribution network services over the 2025–30 period. Its proposal, and our assessment of it under the NEL and NER, are based on a 'building block' approach which looks at five cost components (see Figure 5):

- return on the RAB – or return on capital, to compensate investors for the opportunity cost of funds invested in this business
- depreciation of the RAB – or return of capital, to return the initial investment cost to investors over time
- forecast opex – the operating, maintenance and other non-capital expenses, incurred in the provision of network services
- revenue increments/decrements – resulting from the application of incentive schemes, such as the EBSS and CESS
- estimated cost of corporate income tax.

**Figure 5 The building block model to forecast network revenue**




Source: AER.

Following the AEMC's metering review, Ergon Energy proposed to reclassify legacy metering services from alternative control services to standard control services and proposed to recover through a flat charge per low voltage customer. This issue is discussed further at section 5.

As a result of this change in classification for legacy metering services, all standard control services building block components for Ergon Energy have been affected. For the purpose of our decision, the associated impacts of the metering revenue have been set apart for consistency and are discussed in Attachment 20 – Metering Services. For example, the revenue smoothing profile determined for Ergon Energy's draft decision is based on main standard control services, without the inclusion of metering.

### Revenue smoothing

Our draft decision incudes a determination of Ergon Energy's annual revenue requirement (ARR) (unsmoothed revenue) and annual expected revenue (smoothed revenue) across the 2025–30 period. The smoothed revenues we set in this draft decision are the amounts that Ergon Energy will target for its annual pricing purposes and recover from its customers for the provision of standard control services for each year of the 2025–30 period.[17]

The ARR is the sum of the various building block costs for each year of the regulatory control period, which can be lumpy over the period. To minimise price shocks, revenues are smoothed within a regulatory control period while maintaining the principle of cost recovery under the building block approach. As such, revenue smoothing requires diverting some of the cost recovery to adjacent years within the regulatory control period.

For this draft decision, we approved lower revenues than those in Ergon Energy's proposal. This is mainly driven by our reductions to Ergon Energy's opening RAB and forecast capex. Further reductions are due to external economic factors involving data updates to reflect higher expected inflation rate, which all else equal, reduces the regulatory depreciation building block and lower interest rates, which reduce the return on capital.

On the other hand, our draft decision allows for higher revenues than those determined in the 2020–25 period for the reasons discussed in section 1.1 of this Overview. We have smoothed the expected revenues over the 2025–30 period for Ergon Energy. Our draft decision results in average annual increases of 6.2% (nominal) in the expected revenues for the 2025–30 period.

## 2.1 Regulatory asset base

The RAB accounts for the value of regulated assets over time. To set revenue for a new regulatory period, we take the opening value of the RAB from the end of the last period and roll it forward year by year by indexing it for inflation, adding new capex and subtracting depreciation and other possible factors (such as disposals). This gives us a closing value for the RAB at the end of each year of the regulatory period. The value of the RAB is used to determine the return on capital and regulatory depreciation building blocks. It substantially

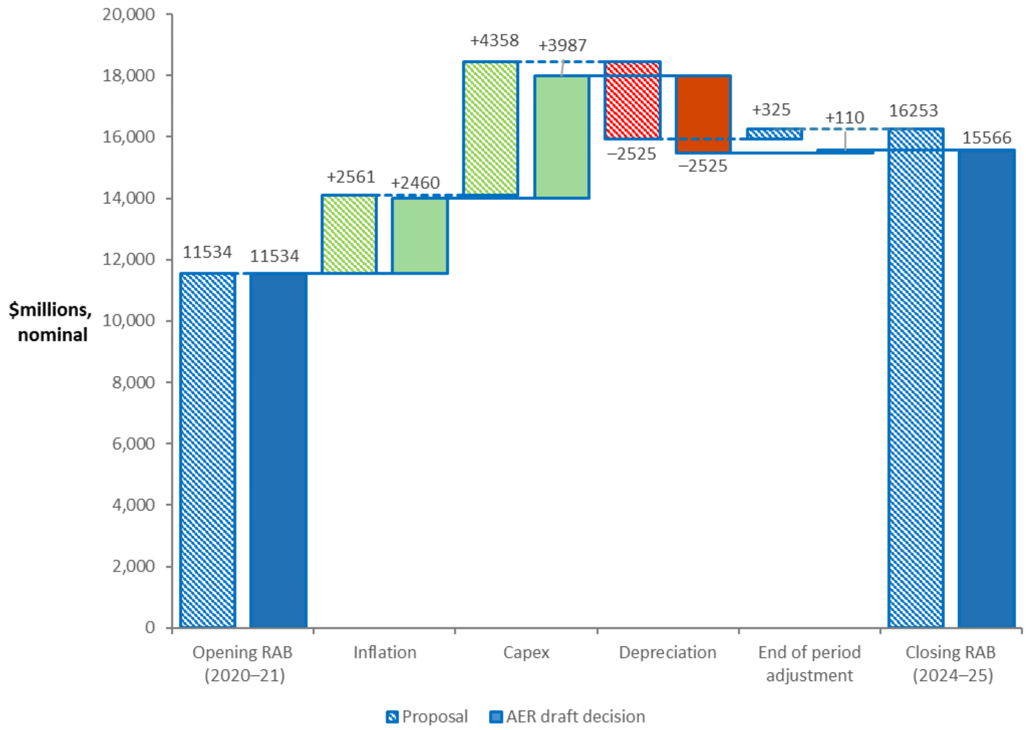
[17] Our draft decision expected revenues have not factored in the legacy metering costs being moved to standard control services, any changes arising from incentive scheme amounts, cost pass throughs or unders/overs reconciliation that usually occur in the annual pricing process to come up with the total allowed revenue.

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 regulatory depreciation components of the revenue determination.

For this draft decision, we have determined an opening RAB value of $15,566.1 million ($ nominal) as at 1 July 2025. This value is $686.9 million (4.2%) lower than Ergon Energy's proposed opening RAB value of $16,253.0 million. This reduction is largely due to our decision to exclude some of Ergon Energy's actual capex from rolling into the RAB to reflect the outcome of our ex-post review of 2018–23 capex (as discussed in Section 2.4).

We have also made updates to the consumer price index (CPI) inputs for 2023–24 and 2024–25 in the roll forward model (RFM) to reflect more up-to-date values. Figure 6 shows the key drivers ($ nominal) of the change in Ergon Energy's RAB over the 2020–25 period compared to its proposal.

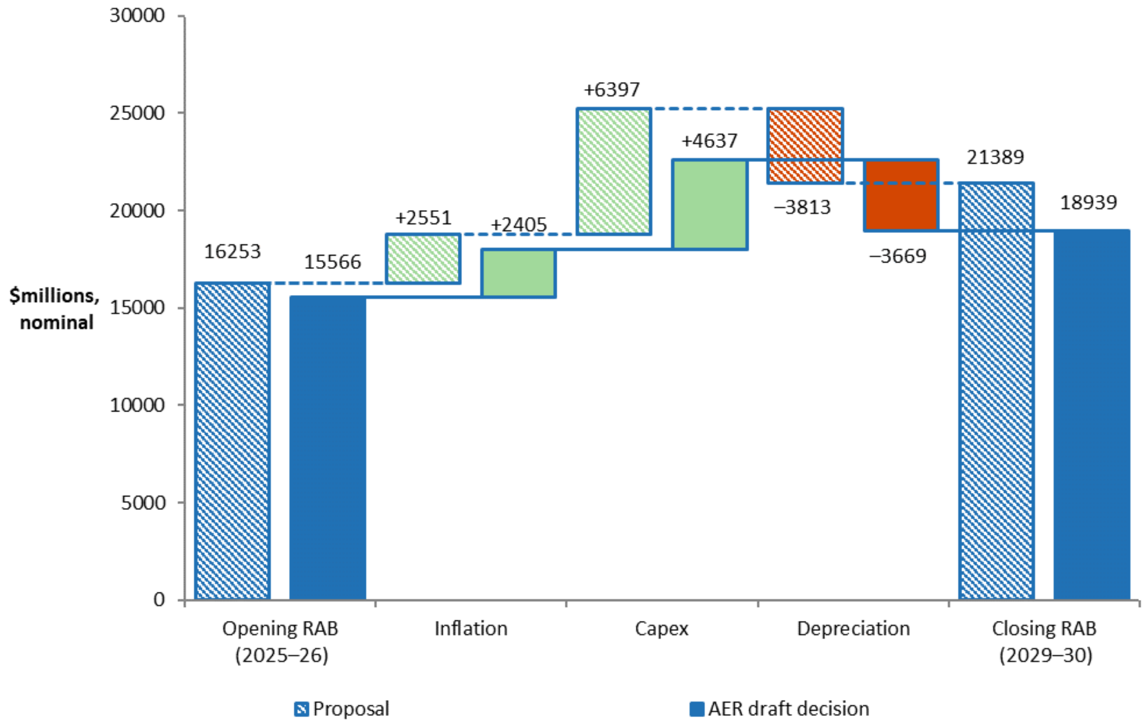
**Figure 6 Key drivers of changes in the RAB over the 2020–25 period – proposal compared with AER's draft decision ($ million, nominal)**




Source: AER analysis.
Note: Capex is net of disposals and capital contributions. It is inclusive of the half-year WACC to account for the timing assumptions in the RFM.

Figure 7 likewise shows the key drivers ($ nominal) of the change in Ergon Energy's forecast RAB over the 2025–30 period compared to its proposal. Our draft decision projects an increase of $3,373.2 million (21.7%) to the RAB by the end of the 2025–30 period compared to the $5,135.6 million (31.6%) increase in Ergon Energy's proposal. We have determined a projected closing RAB of $18,939.3 million ($ nominal) as at 30 June 2030, which is $2,449.3 million (11.5%) lower than Ergon Energy's proposal of $21,388.6 million. This lower value is mainly due to our draft decision to reduce Ergon Energy's proposed forecast capex (discussed in attachment 5). It also reflects our draft decisions on the opening RAB as at 1 July 2025, forecast depreciation and expected inflation.

**Figure 7 Key drivers of changes in the RAB over the 2025–30 period – proposal compared with AER's draft decision ($ million, nominal)**




Source: AER analysis.

Note: Capex is net of forecast disposals and capital contributions. It is inclusive of the half-year WACC to account for the timing assumptions in the PTRM.

## 2.2 Rate of return and value of imputation credits

The return each business is to receive on its capital base (the 'return on capital') is a key driver of proposed revenues. We calculate the regulated return on capital by applying a rate of return to the value of the capital base. We estimate the rate of return by combining the returns of two sources of funds for investment – equity and debt. The allowed rate of return provides the business with a return on capital to service the interest rate on its loans and gives a return on equity to investors.

Ergon Energy's proposal and this draft decision applies the 2022 Rate of Return Instrument:[18]

- Our draft decision applies a rate of return of 6.04% for the first year of the regulatory period, which approximates the placeholder rate of return of 6.04% used in Ergon Energy's proposal.

[18] The 2022 *Rate of Return Instrument* was amended in March 2024. See https://www.aer.gov.au/publications/guidelines-schemes-models/rate-of-return-instrument-2022/final-decision

- Our draft decision and Ergon Energy's proposal applies a value of imputation credits (gamma) of 0.57 as set out in the 2022 Instrument.[19]

Our estimate of expected inflation for the purposes of this draft decision is 2.85% per annum. It is an estimate of the average annual rate of inflation expected over a five-year period based on the approach adopted in our 2020 Inflation Review[20] and the forecast from the Reserve Bank of Australia's August 2024 Statement on Monetary Policy.[21] This is higher than the estimate used in Ergon Energy's proposal (2.80%), which was taken from an earlier Statement on Monetary Policy.

Figure 8 isolates the impact of expected inflation from other parts of our draft decision, to illustrate its impact on the return on capital and regulatory depreciation building blocks and the total revenue allowance. Other elements held constant, lower inflation reduces the return on capital but increases regulatory depreciation.

**Figure 8 Inflation components in draft decision revenue building blocks ($ million, nominal)**


Source: AER analysis.

19 AER, *Rate of return Instrument 2022,* Clause 27. The 2022 *Rate of Return Instrument* was amended in March 2024. See https://www.aer.gov.au/publications/guidelines-schemes-models/rate-of-return-instrument-2022/final-decision

20 AER, *Final position – Regulatory treatment of inflation*, December 2020.

21 RBA, *Statement on Monetary Policy,* August 2024, Table 3.1: Forecast Table. See https://www.rba.gov.au/publications/smp/2024/aug/outlook.html#table-3-1

## 2.3 Regulatory depreciation (return of capital)

Depreciation is a method used in our decision to allocate the cost of an asset over its useful life. It is the amount provided so capital investors recover their investment over the economic life of the asset (otherwise referred to as 'return of capital'). When determining total revenue, we include an amount for the depreciation of the projected RAB. The regulatory depreciation amount is the net total of the straight-line depreciation less the indexation of the RAB.

Our draft decision determines a regulatory depreciation amount of $1,263.7 million ($ nominal) for the 2025–30 period. This is an increase of $2.1 million (0.2%) from Ergon Energy's proposal of $1,261.6 million.

Although our large reductions to forecast capex and the opening RAB have reduced straight-line depreciation, this has been offset by their corresponding effect of reducing the indexation of the RAB.[22]

## 2.4 Capital expenditure

Capital expenditure – the capital costs and expenditure incurred to provide network services – mostly relates to assets with long lives, the costs of which are recovered over several regulatory control periods. Capex is added to Ergon Energy's RAB, which is used to determine the return on capital and return of capital (regulatory depreciation) building block allowances. All else being equal, higher forecast capex will lead to higher projected RAB value and higher return on capital and regulatory depreciation allowances.

Our draft decision is that we are not satisfied that Ergon Energy's capex overspend in the ex-post period (2018–23 period) of $1,195.0 million ($2024–25) reasonably reflects the capex criteria (in particular, we are not satisfied that it reasonably reflects the prudent and efficient costs to meet the capex objectives). Our substitute forecast is $598.8 million, which is 50.0% below Ergon Energy's actual capex overspend. Table 1 provides a breakdown by category of our ex-post draft decision. As can be seen, our position is driven mostly by a reduction of 45.3% to Ergon Energy's repex overspend in the 2018-23 period.

**Table 1 AER Draft Decision: Ergon Energy Ex-post review**

| Capex category | AER Forecast 2018-23 | Ergon Energy actuals 2018-23 | Difference from forecast (assessed overspend)[b] | Proposed overspend to include in the opening RAB |
|---|---|---|---|---|
| Augex | 400.2 | 228.4 | -171.8 | -171.8 |
| Net connections | 270.7 | 314.9 | 44.2 | 44.2 |
| Repex | 989.6 | 2221.5 | 1231.9 | 674.0 |
| ICT[a] | 132.7 | 246.3 | 0.0 | 0.0 |
| Property | 99.8 | 151.5 | 51.7 | 51.7 |
| Fleet | 185.6 | 129.1 | -56.5 | -56.5 |

22 Since RAB indexation is deducted from straight-line depreciation, the lower RAB indexation has resulted in a slightly higher regulatory depreciation.

| | | | | |
|---|---|---|---|---|
| Plant & Equipment | 33.6 | 34.7 | 1.1 | 1.1 |
| Capitalised overheads | 942.1 | 1036.5 | 94.4 | 56.1 |
| **Total capex** | **3054.3** | **4362.9** | **1195.0** | **598.8** |

Source: Ergon Energy and AER analysis.
Note: (a) As Ergon Energy proposes to exclude its ICT overspend from the opening RAB, it is also excluded as part of our assessed capex overspend.
(b) Due to the underspend in augex (-$171.8 million) and fleet ($-56.5 million), the net overspend of $1195.0 million is lower than the total repex overspend of $1231.9 million.

Our draft decision is also to not accept Ergon Energy's forecast total net capex of $5,704.8 million ($2024–25) for the 2025–30 period. Our alternative forecast is $4,188.1 million which is 26.6% lower than Ergon Energy's forecast. Table 2 sets out our draft decision for Ergon Energy's forecast capex by capex category.

### Table 2 AER's draft decision by capex category ($million, $2024–25)

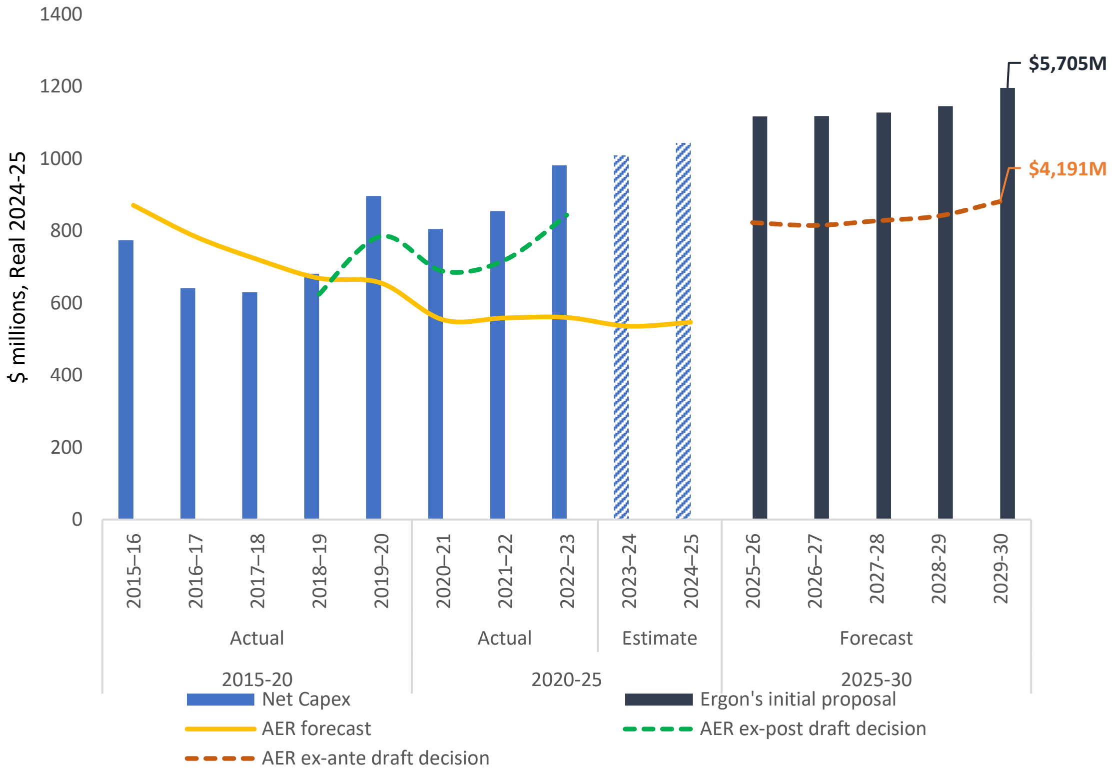
| Capex category | Ergon Energy's proposal[a] | Forecast assessed[bc] | AER's draft decision |
|---|---|---|---|
| Repex | 2545.6 | 2718.8 | 1844.3 |
| Resilience | N/A | 53.1 | 26.8 |
| Augex | 763.4 | 513.2 | 429.2 |
| Connections | 321.2 | 321.2 | 321.2 |
| Fleet | 243.0 | 243.0 | 210.1 |
| Property | 174.7 | 174.7 | 170.7 |
| Cyber security | N/A | 53.4 | 53.4 |
| ICT | 288.3 | 258.8 | 208.7 |
| CER integration | 63.0 | 63.0 | 63.0 |
| Other non-network | 31.7 | 31.7 | 31.7 |
| Capitalised overheads | 1316.1 | 1316.1 | 874.4 |
| **Total capex (excluding capcons)** | **5746.9** | **5746.9** | **4233.5** |
| less asset disposals | -42.1 | -42.1 | -42.1 |
| Modelling adjustments | | | -3.4 |
| **Net capex** | **5704.8** | **5704.8** | **4188.1** |

Source: Ergon Energy and AER analysis. Numbers may not sum due to rounding.
Note: (a) Ergon Energy's proposal differs from its proposal documents as it submitted an updated capex model on 28 June 2024. It originally proposed net capex of $5783.0.
(b) Our forecast assessed re-categorised capex from Ergon Energy's proposal to align with how we assessed each category. We re-categorised $7.9 million of repex, $16.1 million of augex and $29.4 million of ICT to cyber security, and re-categorised $53.1 million of augex to resilience.
(c) Consistent with how we assessed CTG/CTS capex in the ex-post review, we have re-categorised $181 million of Ergon Energy's proposed CTG/CTS capex from augex to repex.

Figure 9 shows Ergon Energy's historical capex trend, the overspend in the ex-post period, its proposed forecast for the 2025–30 regulatory control period, and our draft decision. As can be seen, Ergon Energy proposes to further increase its already elevated level of capex in the ex-post period into the forecast period. Figure 9 also shows that our draft decision on the ex-post review accepts some of Ergon Energy's overspend. Also, our draft decision on Ergon Energy's forecast capex trend is relatively in line with our draft decision on the ex-post review.

We note that the estimates in the last two years of the current period are higher than the first three years in the current period. This would suggest that another ex-post review is a possibility in Ergon Energy's next revenue determination.

**Figure 9 Ergon Energy's historical and forecast capex ($ million, $2024–25)**




Source: Ergon Energy's proposal and AER analysis.
Note: Capex is net of asset disposals and capital contributions. As Ergon Energy proposes to exclude its ICT overspend from the opening RAB, we have excluded its ICT overspend from its net capex for years 2020-21 to 2022-23.

## Ex-post

We reviewed Ergon Energy's capex overspend in line with the ex-post staged review process set out in the AER's Capital Expenditure Incentive Guideline for Electricity Network Service Providers.[23] The first stage considers whether the overspend is significant at the total forecast capex level. If the DNSP's capex overspend warrants further assessment, stage 2 involves a deeper bottom-up review of the capex overspend.

Overall, we have assessed that, at the total forecast capex level, Ergon Energy's total capex overspend of $1,195.0 million is significant. As such, we consider that further assessment is warranted.

[23] AER, *Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, April 2023, pp.13-15.

We found that the repex category contributes the most to the overspend. The overspend in repex of $1,231.9 million represents 86.6% of the capex categories that have an overspend.[24] Therefore, at stage 2 of the ex-post review process, we have undertaken a bottom-up review of the overspend in repex. In the other areas of overspend; that is, in property, ICT and connections, we undertook a high-level review and found the capex incurred to be within a reasonable range.

In undertaking our bottom-up review, we had regard to all the information before us. This includes the advice from our independent engineering/technical consultant, EMCa, who we engaged to undertake its own ex-post review in parallel with the AER's ex-post review.

We placed the greatest weight on information provided by Ergon Energy. We had regard to Ergon Energy's regulatory proposal, including all supporting information such as models, data, business cases, consultant reports and cost benefit analysis. We issued Ergon Energy with numerous information requests (60+) and held face-to-face meetings about information gaps, data errors, and further detail given the lack of information in its proposal.

We and our consultant EMCa also engaged extensively with Ergon Energy throughout our assessment process, including extensive face-to-face deep dive sessions attended by Ergon Energy's subject matter experts including its senior engineers, asset managers, and regulatory managers.

We also had regard to stakeholder comments in response to our Issues paper. We also met with the Electrical Safety Office (ESO) to discuss any comments it had about Ergon Energy's proposal.

Overall, we found that Ergon Energy's supporting documentation contained significant information and data gaps, data discrepancies and reconciliation issues, and lack of detail and sufficient reasoning to substantiate the prudency and efficiency of its proposal. EMCa came to the same conclusion.

Due to the information gaps and Ergon Energy's inability to provide further detailed information and evidence, we explored other avenues of investigation. This included a review of the Regulatory Information Notice (RIN) data, testing Ergon Energy's performance against the repex model, and other comparative benchmarking exercises.

*Our findings*

Based on the information before us, we consider that some of Ergon Energy's overspend was justified given the circumstances at the time of its investment decision.

At this stage, Ergon Energy has not provided us with sufficient evidence that the total overspend reflects the decisions of a prudent and efficient operator. Our findings in the three primary drivers for the repex overspend are summarised below.

Consistent with the NEO, in making our draft decision we have had regard to the need for Ergon Energy to operate a safe network. In particular, our draft decision includes:

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24 As the net overspend of $1,195.0 million includes the underspend in augex and fleet which is higher than $1,231.9 million, this percentage calculation is only based on the capex categories that have overspend and assessed as part of our ex-post review (i.e. excluding the augex and fleet underspend).

- Accepting some of the overspend on pole asset replacement by including a ‘catch up’ period using a longer time series
- Accepting all the actual and proposed forecast conductor asset replacement
- Accepting all the actual and some of the proposed forecast stand-alone (targeted) pole top structure asset replacement
- Accepting all the actual and proposed forecast stand-alone (targeted) service asset replacement
- Accepting all the actual and proposed defect volumes for the clearance programs.

Based on our discussion with the ESO and the information and evidence submitted to us to date, it is our understanding that these are the key areas of repex where they may be safety concerns.

We found no emerging safety risk related to transformers and switchgears assets, which is the key area of the repex overspend.

<u>Poles overspend</u>

Ergon Energy overspent by $341.3 million on pole assets, which accounts for 27.7% of the total repex overspend.

We found a genuine need for Ergon Energy to overspend on some its pole repex during the ex-post period. In particular, we are cognisant that Ergon Energy in 2019-20 exceeded the three-year moving average limit of an average pole failure rate of 1 per 10,000 poles set out in the Queensland Electrical Safety Code of Practice (ESCOP).[25]

However, we consider that Ergon Energy’s response of adopting Energex’s pole management practices and standards has resulted in higher pole replacement than is efficient. Energex, as an urban network, has an inherently different risk profile compared to Ergon Energy’s predominately rural network. This is because, when compared to Ergon Energy’s network, Energex’s higher customer density network consists of higher demand per line, which results in more customers losing supply during asset failures. Safety risks are also higher in an urban network when compared to a predominantly rural network due to the higher probability of public exposure from assets being in closer proximity to urban centres.

While Energex’s pole practices might be appropriate for Energex’s network to maintain its overall safety and reliability performance, applying Energex’s practices and standards has led to unnecessarily high costs to maintain asset performance. In addition, we note that Energex’s current pole performance is outperforming the ESCOP’s outlined failure rate of 1 per 10,000 poles by about 400% (i.e. it had a failure rate of 1 per 48,000 poles in the 2018-23 period).

There is also a lack of evidence to support the prudency and efficiency of the higher pole expenditure at the time of the investment. Consistent with good industry practice, we would expect a prudent and efficient operator to undertake a review like a root cause analysis to determine the underlying problem with its poles and therefore target the replacement. The lack of a root cause analysis was also raised by the CCP.26 We would encourage Ergon Energy to provide us with evidence of a root cause analysis if this was undertaken.

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25 Since the changes in Ergon Energy’s pole management practices in early 2019, we observed a reduction in the annual pole failures in 2020-21 and 2022-23.

26 CCP30, *Advice to the AER regarding the Energex and Ergon Energy regulatory proposals 2025-30*, May 2024, p. 12.

Ergon Energy also did not provide evidence that it tested the outcomes from applying Energex's pole management practices and standards, and business cases were not undertaken to support Ergon Energy's revised poles forecast. For example, Ergon Energy did not undertake a Regulatory Investment Test – Distribution (RIT-D) or equivalent analysis to test the costs and benefits of different options to address the increase in unassisted pole failures.

DNSPs are required to apply the RIT-D in accordance with cl 5.17.3 of the NER, unless one of the exceptions in cl 5.17.3(a) applies.

The AER's position is that a RIT-D will normally be required for a program to replace multiple assets of the same type, where the program results from changes to engineering criteria for asset replacement and its cost exceeds the relevant financial threshold. The AER clarified this position in a Compliance Bulletin in 2021.

It is therefore possible that when Ergon Energy made modifications to its pole serviceability criteria, its failure to apply the RIT-D in accordance with cl 5.17.3 may have been a breach of the NER, although we note these modifications pre-dated the AER's 2021 Compliance Bulletin.

The AER intends to address Ergon Energy's pole replacement through this regulatory process rather than compliance channels, but will continue to engage with all distributors to foster compliance with the NER and to ensure the AER's expectations as set out in its Compliance Bulletin are understood.

Absent the above type of evidence, we do not have confidence that its investment in higher pole expenditure has been tested against feasible options and is the one that results in the greatest benefit to consumers.

Opportunistic replacement

Ergon Energy overspent by approximately $544.0 million on opportunistic replacement, which accounts for 44.2% of the total repex overspend.[27]

Opportunistic replacement is a practice where other assets are replaced at the same time as targeted assets. These other assets are at the same location as targeted assets but are usually of lesser value and at a lower level of replacement priority.

Opportunistic replacement can be considered good industry practice where it leads to cost efficiencies. This may involve, for example, replacing low value assets such as an aging cross-arm or conductor during a pole replacement. However, Ergon Energy's opportunistic replacement makes up to 44% of the total overspend with larger assets like transformers and switchgears making up to 52% of these opportunistic replacements. We found no emerging safety risk related to these assets.

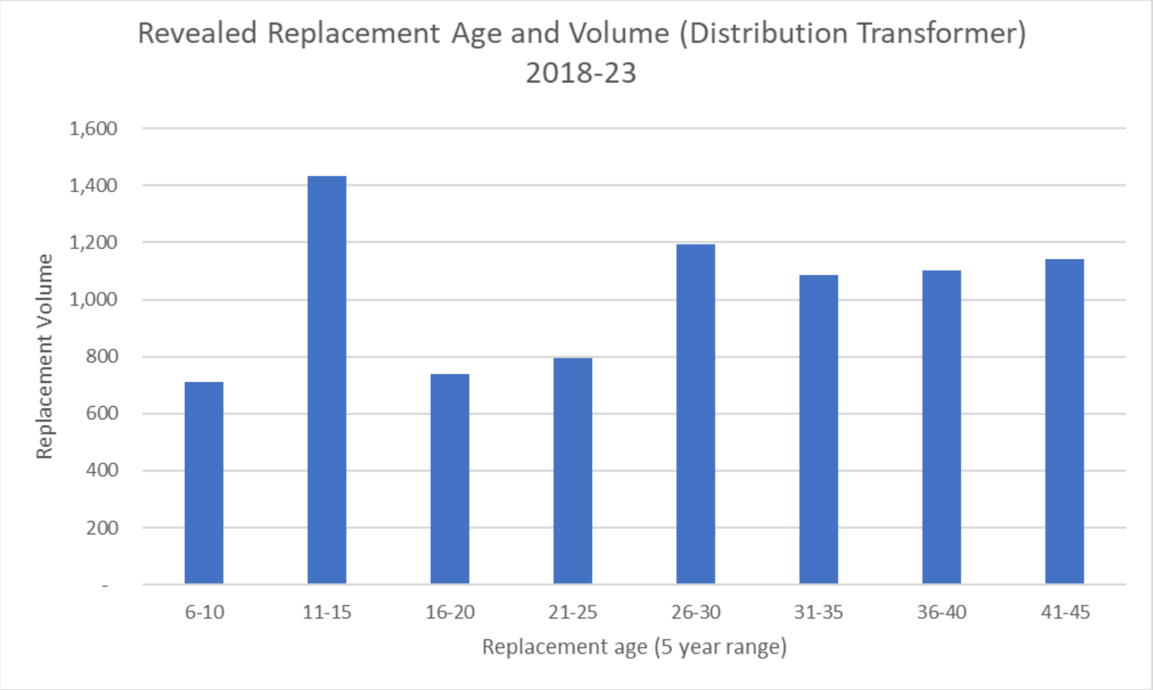
Our review of Ergon Energy's supporting material is that, in many instances, opportunistic replacement has not been cost effective, and there is a lack of evidence to support the prudency and efficiency of these investments.

We found that Ergon Energy has been replacing assets much earlier than the end of their economic life, where there are no emerging or existing defect issues, or the defects are identified as low priority. We also found evidence that replacing these assets earlier is against Ergon Energy's own business rules for opportunistic replacement. For example,

[27] While it is possible some defective assets are replaced as part of opportunistic replacement, Ergon Energy did not provide sufficient information for us to verify these assets.

Figure 10 shows the revealed replacement age of Ergon Energy's distribution transformers. As can be seen, the revealed age of replacement is much earlier than the typical economic and design life of a transformer of 45 to 55 years.

**Figure 10 Revealed Age of Replacement of Distribution Transformers**




More generally, we observe that Ergon Energy's inefficiently higher volumes of opportunistic replacement of these assets is likely to result in greater emission levels, which is not in the long-term interests of consumers.

Clearance-to-Ground/Clearance-to-Structure (CTG/CTS)[28]

We acknowledge Ergon Energy's regulatory obligations in relation to CTG/CTS in the *Electrical Safety Regulation 2013* (QLD). In particular, we appreciate that Ergon Energy must address breaches of its clearance limits. We also met with the ESO who indicated that a few improvement notices had been served to Ergon Energy in recent years about its CTG/CTS program.

We accept that Ergon Energy has legislative obligations to address breaches of its clearance limits and we have accepted the incurred conductor clearance volumes in the ex post period.

However, we found that the primary driver of the overspend has been an almost doubling of unit rates. Based on the information submitted by Ergon Energy, we found that about half its CTG defects have a clearance gap of less than 20cm. In this respect, we consider that Ergon Energy did not act in a prudent and efficient manner in choosing the considerably more expensive option of replacement compared to the lower cost industry-accepted practice of re-tensioning (or a combination of re-tensioning and staking), particularly for defects that had a clearance gap of less than 20cm.

[28] During the 2020-25 period, Ergon Energy re-categorised $40.9 million of CTG/CTS expenditure from repex to augex. For a like for like comparison with our 2018-23 AER forecast, we have re-categorised this $40.9 million back to repex for our assessment purposes.

### *Our draft decision is a placeholder*

We see our draft decision as a placeholder. There may be other information not currently available to the AER which could mean a more optimal estimate can be achieved. In this regard, we encourage Ergon Energy to engage with us prior to its submission of its revised proposal to discuss what further information is available to support its proposal. In section A.3.1.3, we set out the information and data gaps we have identified in Ergon Energy's proposal and would expect to be addressed in its revised proposal. We would also expect that Ergon Energy genuinely engage with its stakeholders about its revised proposal, in particular, In particular, it should be transparent about whether the overspend has addressed expected risks, which was raised as a concern by the CCP[29] and RRG[30] in their submissions to the Issues Paper.

Due to our concerns with the information and data provided to us, we have had to explore other avenues to derive an alternative estimate. We have explored other approaches including bottom-up analysis, backcasting using the repex model and other forms of benchmarking analysis. However, the data discrepancies, errors, reconciliation issues and information gaps we encountered meant we did not have sufficient confidence in the robustness of the data to undertake a more detail bottom-up estimate. Thus, our alternative overspend estimate for Ergon Energy's poles overspend is based on benchmarking Ergon Energy's pole replacement rate against Essential Energy.

We undertook comparative analysis between Ergon Energy and other DNSPs and found Essential Energy as the best available business to compare with Ergon Energy. This is because Essential Energy faces similar challenges with the age and conditions of its pole population as Ergon Energy. In particular, we found that Ergon Energy and Essential Energy have similar pole composition and operating environment factors (similar rainfall and humidity levels) that is likely to impact age and condition of its pole populations. For example, both businesses have similar customer line density (5.5 versus 5.2) and relative proportion of timber, steel and concrete poles. In comparison, Energex's customer line density is more than 6 times higher (34.2 versus 5.5) with less than half the timber pole population (405,578 versus 871,347). While Essential Energy has 29.1% more timber poles compared to Ergon Energy, it also has 28.2% more customers. In comparison, Energex's has 111.7% and 65.2% more customers compared to Ergon Energy and Essential Energy respectively.

In applying this approach, we have erred on the conservative side as we did not benchmark Ergon Energy against other potential comparators such as AusNet and Powercor which have a regional component to their service area. We note that Ergon Energy would have performed worse if we had included these businesses because of their longer replacement lives. We also did not take account of Ergon Energy's younger asset lives in our benchmarking and did not pursue concerns raised by EMCa about Ergon Energy's

[29] CCP30, *Advice to the AER regarding the Energex and Ergon Energy regulatory proposals 2025-30*, May 2024, p. 12.

[30] RRG, *Submission on Ergon Energy and Energex electricity distribution regulatory proposals 2025–30 and the Australian Energy Regulator's Issues Paper*, May 2024, p. 4.

inefficiently high unit costs in some areas[31] and the overspend in the stand-alone programs for pole top structures and services.[32]

We also note that our alternative overspend estimate includes an additional amount for the useful life of the asset replaced even when the asset has been replaced earlier than efficient. We consider our approach incentivises prudent and efficient decision-making as it ensures that Ergon Energy is not penalised going forward for inefficient investments made in the ex-post period.

**Forecast capex**

We have accepted some parts of Ergon Energy's forecast where it provided sufficient evidence to support the prudency and efficiency of its forecast; this being in the areas of cyber security capex, CER integration and other non-network. In addition, we have accepted the following elements of the repex forecast:

- conductor asset replacement
- the stand-alone (targeted) service asset replacement
- the proposed defect volumes for the CTG/CTS programs.

However, in some areas, we found a lack of evidence and detail, information gaps and had concerns with Ergon Energy's analysis. This is in the areas of repex, augex, resilience, fleet, property, ICT and capitalised overheads. To provide guidance for Ergon Energy in preparing its revised proposal, we have noted information gaps and areas for improvement for forecasting and supporting information.

We also note that Ergon Energy did not satisfy any of the capex expectations in the Handbook. In particular, its forecast capex for the 2025-30 period is a 18.5% step up from the ex-post period, where it is proposing a step up in all capex categories except for ICT. Submissions in response to the Issues paper also noted the lack of genuine consumer engagement on its capex proposal. There was little evidence of how Ergon Energy had regard to consumer feedback in developing its capex proposal especially on the key priority issue of affordability.

In summary, in our bottom-up review, we came to the following findings:

- *Repex* - We observed some improvements in Ergon Energy's supporting material where it has undertaken risk-cost modelling. However, contrary to its own statements, it did not rely on the results of the modelling to derive its forecast. Instead, we found that its forecast was based on a continuation of its current level of asset replacement for each asset class. Its forecast therefore continues the high levels of replacement activity and expenditure that we consider Ergon Energy has not adequately justified in the ex-post period. This includes continued high inefficient levels of opportunistic replacement where assets are replaced earlier than efficient. We also found its cost benefit analysis

31 EMCa, *Ergon Energy 2025/26 to 2029/20 Regulatory Proposal, Review of Aspects of Proposed Expenditure*, September 2024, pp. 78-80.

32 EMCa, *Ergon Energy 2025/26 to 2029/20 Regulatory Proposal, Review of Aspects of Proposed Expenditure*, September 2024, p. 66.

contained a number of errors, overstated benefits, and was biased towards its preferred option.

- *Augex* – We found that Ergon Energy did not provide sufficient evidence to support some of its augex projects. In particular Ergon Energy's forecast for grid communications, protection and control is overstated with an overall lack of overarching strategy, minimal options analysis, and deliverability concerns. We acknowledge the need for investments by networks to support a safe and reliable network. However, without enough supporting evidence, we were unable to accept Ergon Energy's proposed augex for this category against our capex criteria. We have also not accepted expenditure for the Distribution Feeder Augmentation Maintain Reliability project due to a lack of evidence to support the prudency.
- *ICT* – In the business cases we assessed, we found that Ergon Energy did not provide adequate evidence to support the prudency and efficiency of its preferred options. Some of its preferred options did not have the highest ranked NPV and some of its business cases had no quantitative benefits while the qualitative benefits lacked detail. The information on the scope of works and costs provided insufficient detail to determine the efficiency of the costs.
- *Resilience* – Ergon Energy did not provide much of the evidence expected in reliance-related proposals that the AER set out in its guidance note on network resilience. While we have accepted its forecast for its bushfire and flood program and mobile substations, we have concerns about the prudency and efficiency of its mobile generation program and SAPS program, and therefore have not accepted this component of its resilience expenditure.
- *Fleet* - We found that Ergon Energy did not provide sufficient evidence to support a 46% step up in its forecast relative to the current period. In particular, Ergon Energy did not provide sufficient justification for its proposed changes to the replacement strategies of elevated work platforms (EWP) and crane borers. We have also adjusted its forecast lower to reflect a lower FTE uplift given the relationship between the FTE uplift and capex.
- *Capitalised overheads* – We found the methodology that Ergon Energy has used to calculate its capitalised overheads to not be reasonable. Our alternative estimate applies the AER's standard methodology.

## 2.5 Operating expenditure

Opex is the forecast of operating, maintenance and other non-capital costs incurred in the provision of standard control services. Forecast opex is one of the building blocks we use to determine Ergon Energy's total regulated revenue requirement.

Our draft decision is to accept Ergon Energy's main standard control services opex forecast of $2,379.1 million ($2024–25), including debt raising costs. This is because our alternative estimate of $2,401.8 million is higher ($22.8 million ($2024–25), or 1.0%) than Ergon

Energy's total opex forecast proposal. Therefore, we consider that Ergon Energy's total opex forecast satisfies the opex criteria.[33]

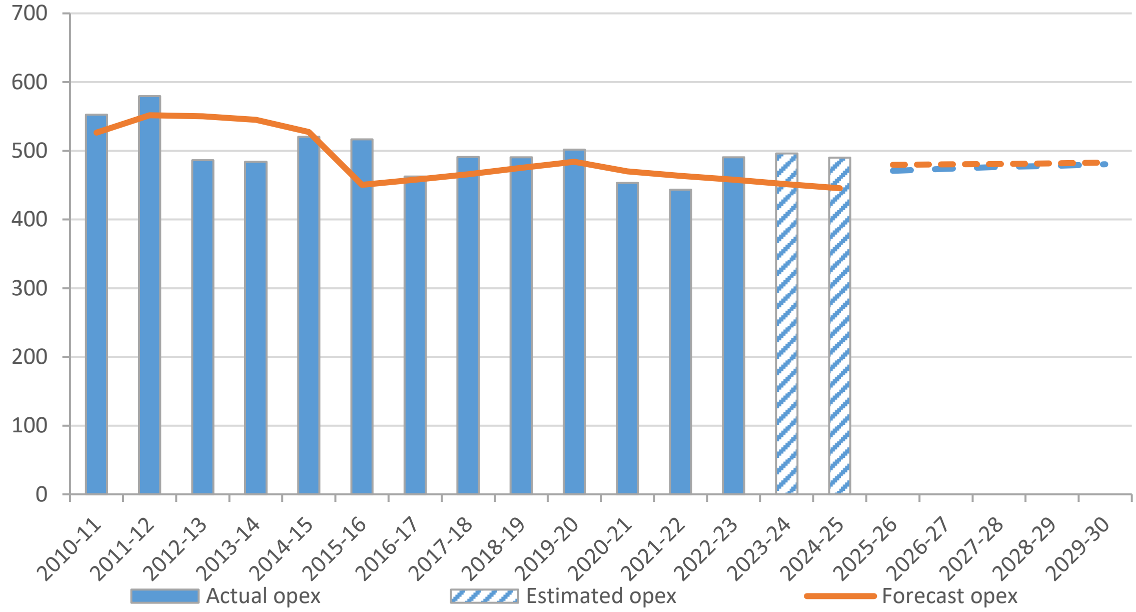
We recognise the forecast moderation in opex by Ergon Energy over the next regulatory control period, including in terms of its base year efficiency, productivity adjustments and only one proposed step change for network visibility.

Our draft decision, which is the same as Ergon Energy's proposed total opex forecast is:

- $5.8 million ($2024–25) (or 0.2%) higher than Ergon Energy's actual (and estimated) opex in the 2020–25 regulatory control period
- $90.8 million ($2024–25) (or 4.0%) higher[34] than the opex forecast we approved in our final decision for the 2020–25 regulatory control period.

In Figure 11 we compare our alternative estimate of opex (the orange dashed line) to Ergon Energy's proposal (the blue dashed line) for the next regulatory control period. We also show the forecasts we approved for the last two regulatory control periods and Ergon Energy's actual and estimated opex over these periods. As can be seen, our draft decision (Ergon Energy's proposal) represents an increase relative to the level of opex we forecast for the 2020–25 regulatory control period. This increase is mainly driven by the trend forecast and the network visibility step change. It is also slightly higher than Ergon Energy's actual and forecast opex over the current regulatory control period.

**Figure 11 Historical and forecast opex ($2024–25)**




Source: Ergon Energy, *Economic benchmarking – regulatory information notice responses 2010–23*; AER, *Final decision PTRM 2010–15*, May 2010; AER, *Final decision PTRM 2015–20*, October 2015; AER, *Final decision PTRM 2020–25* and *Opex Model*, June 2020; Ergon Energy, *2025–30 Regulatory proposal*, January 2024; AER analysis.

33 NER, cl. 6.5.6(c)-(d).

34 This difference is calculated using the opex allowance for the five-year 2020–25 period converted to real $2024–25 using unlagged inflation. The difference of $165.8 million (7.5%) stated in section 1.1 has been calculated using lagged inflation.

Our higher alternative estimate of total opex is primarily due to differences between Ergon Energy's and our approach to making an efficiency adjustment to Ergon Energy's base year opex and our use of a lower productivity growth forecast.

- Ergon Energy proposed a 2.3% efficiency adjustment to its base year opex and did not include transition costs to provide it with a glide path over the next regulatory control period to the more efficient level of base opex it proposed. We applied a slightly lower efficiency adjustment to base opex of 1.9% but added $18.3 million ($2024–25) in transition costs. The transition costs recognise it will take time, and involve costs to implement the required programs to realise opex reductions. Overall, this means we made a lower total efficiency adjustment to base opex.
- For the productivity growth forecast, Ergon Energy proposed 1.0% per annum productivity growth while we adopted our standard 0.5% growth rate.

In our final decision, we will update our alternative estimate of total opex to reflect actual opex for 2023–24, as well as make other mechanical updates. Our draft decision is based on the estimate of base year opex included in Ergon Energy's initial proposal because actual data for 2023–24 was not available at the time the proposal was submitted.

During consultations with the AER on its initial proposal, Ergon Energy indicated its actual opex for 2023–24 is likely to significantly exceed the estimate it provided in its initial proposal. For our final decision we will need to consider actual opex for 2023–24 as reported in Ergon Energy's revised proposal. In particular, we will examine the drivers of the increase, any proposed adjustments to remove non-recurrent costs, whether 2023–24, or some other year, best represents the nature of costs required for the next regulatory control period, and the efficiency of the base year.

## 2.6 Corporate income tax

Our determination of the total revenue requirement includes the estimated cost of corporate income tax for 2025–30 period. Under the post-tax framework, this amount is calculated as part of the building blocks assessment using our post-tax revenue model (PTRM).

Our draft decision determines an estimated cost of corporate income tax amount of $69.8 million ($ nominal) for Ergon Energy over the 2025–30 period. This is an increase of $65.3 million from Ergon Energy's proposal of $4.6 million.

This increase is primarily due to our draft decision on a lower tax depreciation amount, caused by our draft decisions to reduce forecast capex and the opening tax asset base as at 1 July 2025. Tax depreciation is a tax expense. Therefore, a lower tax depreciation increases the estimated taxable income for Ergon Energy which in turn increases the estimated cost of corporate income tax.

## 2.7 Revenue adjustments

Our calculation of Ergon Energy's total revenue includes adjustments for incentive schemes that applied in its determination for the current period, such as under the EBSS and CESS. These mechanisms provide a continuous incentive for Ergon Energy to pursue efficiency improvements in opex and capex, and a fair sharing of these between Ergon Energy and its users. Our draft decision includes:

- EBSS - a revenue adjustment (penalty) of $196.8 million ($2024–25) under the EBSS. This is slightly lower than Ergon Energy's proposed penalty of $199.0 million ($2024–25) because we have used the most recent inflation figures. The full detail on our draft decision for the EBSS is in Attachment 8.
- CESS - a revenue adjustment (penalty) of $490.2 million ($2024–25) under the CESS. This is lower than Ergon Energy's proposed penalty of $714.4 million ($2024–25) because we have used the most recent inflation data and adjusted the CESS applicable capex to exclude Ergon Energy's ICT overspend and the findings from our ex-post review. The full detail on our draft decision for the CESS is in Attachment 9.
- DMIAM - comprises a fixed allowance of $0.2 million ($2017), plus 0.075% of the annual revenue requirement for each regulatory year, as set out in our post -Tax Revenue Model (PTRM). In our final distribution determination, we will determine the amount of the DMIAM allowance for Ergon Energy for the 2025–30 period, based on the final PTRM for Ergon Energy.

The combined effect of these revenue adjustments is a negative $679.9 million ($2024–25) revenue adjustment building block in this draft decision compared to the negative $905.6 million in Ergon Energy's proposal.

# 3 Incentive schemes

Incentive schemes are a component of incentive-based regulation and complement our approach to assessing efficient costs. They provide important balancing incentives under network determinations, encouraging businesses to pursue expenditure efficiencies while maintaining the reliability and overall performance of the network.

Our draft decision on the application of these schemes and allowances is consistent with the position taken in our Framework and Approach paper and is set out in Attachments 8-12 of this draft decision.  Our draft decision is that the following incentive schemes will continue to apply to Ergon Energy in the 2025–30 period:

- Efficiency benefit sharing scheme (EBSS). This provides a continuous incentive to pursue efficiency improvements in main standard control services opex and provide for a fair sharing of these between networks and network users. Consumers benefit from improved efficiencies through lower opex in regulated revenues for future periods. The full detail on our draft decision for the EBSS is at Attachment 8.
- Capital expenditure sharing scheme (CESS). This incentivises efficient capex throughout the period by rewarding efficiency gains and penalising efficiency losses, each measured by reference to the difference between forecast and actual capex. Consumers benefit from improved efficiencies through a lower RAB, which is reflected in regulated revenues for future periods. We have adjusted the CESS applicable capex to reflect our decision on Ergon Energy's proposed ICT exclusion and ex-post review. Our reasoning behind these positions is outlined in further detail in Attachment 9.
- Service target performance incentive scheme (STPIS). The STPIS balances a business' incentive to reduce expenditure with the need to maintain or improve service quality. It achieves this by providing financial incentives to businesses to maintain and improve service performance and not by simply reducing costs at the expense of service quality. Once improvements are made, the benchmark performance targets will be tightened in future years. The parameters that will apply to each of component of the STPIS for Ergon Energy are set out in Attachment 10.
- Demand Management Incentive Scheme (DMIS) and Demand Management Innovation Allowance Mechanism (DMIAM). The DMIS provides network service providers with financial incentives for undertaking efficient demand management activities. The DMIAM funds research and development in demand management projects that have the potential to reduce long-term network costs. Our draft decisions are set out in Attachment 11.

Since our last determination for Ergon Energy, we have introduced the customer service incentive scheme (CSIS). This scheme is designed to encourage electricity distributors to engage with their customers, identify (through customer engagement) the customer services their customers want improved, and then set targets to improve those services based on their customers' preferences and support. Ergon Energy chose not to apply a CSIS for the 2025–30 period.

# 4 Tariff structure statement

Ergon Energy's 2025–30 proposal includes its third tariff structure statement. Its current tariff structure statement applies to 30 June 2025. While our draft decision does not accept elements of Ergon Energy's tariff proposal, we think Ergon Energy is making progress on network tariff reform, responding to feedback and supporting the energy transition.

The requirement on distributors to prepare a tariff structure statement stemmed from significant reforms in 2014 to the rules governing distribution network pricing. A tariff structure statement informs customer choices by:

- providing clear price signals—network tariffs which reflect what it costs to use electricity at different times can allow customers (or their retailer) to make informed decisions to better manage their bills
- transitioning tariffs to greater cost reflectivity—with the requirement that distributors explicitly consider the impacts on retail customers, by engaging with customers, customer representatives and retailers in developing network tariff proposals
- managing future expectations—providing guidance for retailers, customers and suppliers of services such as local generation, batteries and demand management by setting out the distributor's tariff approaches for a set period of time.

It is important to note that the network tariff price signals we approve may not be directly passed on to end-use customers (i.e. the retail customer). Network costs and price signals are charged directly to retailers who then pass these costs on to end-use customers in their retail offers. A retailer may choose to pass on the network price signals exactly or repackage them into their retail offers (including flat rate retail offers). Cost reflective network tariffs should not inhibit consumer choice over retail tariff structures. Customers should have access to a range of retail tariff structures across different retailers, including because distributors typically offer at least two cost reflective tariffs structures for small customers, and because retail tariffs are not required to reflect the structure of the underlying network tariff.

Network tariff reform enables distributors to charge retailers in a manner which more closely reflects the cost of providing electricity network capacity to end-use customers and can support the energy transition currently underway. Where price signals are passed through, and if customers are well placed to respond to these price signals, appropriately structured tariffs can enable growth in the value and number of people with consumer energy resources (CER). At the same time, this response to price signals can reduce network constraints and minimum load issues and therefore reduce the level of network investment required, resulting in lower prices for all consumers.

The tariff structure statement must set out several matters. These include tariff classes, proposed tariffs and the structures and charging parameters, the strategy for introduction of export tariffs, and the approach to setting tariff levels in each year of the regulatory control period.[35] The policies and procedures that will be used to assign customers to tariffs or reassign customers from one tariff to another must also be outlined.

In this determination we must decide whether to approve Ergon Energy's tariff structure statements, which will form the basis of annual pricing proposals throughout the 2025–30 period.[36] We are also required to decide the policies and procedures for assigning or re-assigning customers to tariff classes.[37] Principally, we are making a determination on whether the proposed tariff structure statement complies with the pricing principles of the NER, and any other applicable rules. After that, our decision takes the NEO into account and considers whether the tariff structure statement will or is likely to contribute to achievement of the NEO. For tariff structure statements, we consider the NEO elements of price and achievement of jurisdictional emissions reduction targets to be most relevant.

While an indicative pricing schedule must accompany the tariff structure statement, the tariff levels for each tariff for each year of the 2025–30 period are not set as part of this determination.[38] Tariff pricing levels for the regulatory year commencing 1 July 2025 will be subject to a separate approval process in May 2025, after we have made our final revenue determination in April 2024. Tariff price levels for the four years from 1 July 2026 will also be approved on an annual basis.[39]

We commend Ergon Energy for submitting a tariff structure statement that seeks to balance a broad range of stakeholder views and provides a forward-looking path to transition customers to more cost-reflective tariffs. We have given weight to the stakeholder engagement Ergon Energy undertook in developing its tariff structure statement, as well as the submissions we have received. We have also given weight to ongoing AEMC rule change processes, an accelerating smart meter roll out and feedback from stakeholders that some customers are unable to respond to cost reflective tariffs.

In its proposed tariff structure statement Ergon Energy continues to move towards more cost reflective tariff structures in recognition of the changes taking place in the electricity sector and the increasing levels of CER connected to its network. This is evidenced by the introduction of tariffs and modification of existing tariffs with stronger price signals to better encourage more energy consumption during solar peak periods, less during peak load times, and to reward people for exporting energy to the grid when it is most needed. These include export reward tariffs. Ergon Energy has maintained customer choice, for example allowing customers with solar panels the option to opt-out of export reward tariffs if they enter into a dynamic connection with the network. Ergon Energy has also streamlined its suite of tariffs, by withdrawing obsolete tariffs or those with zero or very few customers.

Our draft decision accepts many elements of Ergon Energy's proposed tariff structure statement that comply with the pricing principles and contribute to achievement of the NEO (both price and achievement of jurisdictional emissions targets elements). The fundamental change we require of Ergon Energy is to shift default assignment for residential and small business customers with smart meters from time-of-use demand tariffs to time-of-use tariffs.

[35] NER, cl. 6.18.1A(a).

[36] NER, cl. 6.12.1(14A).

[37] NER, cl. 6.12.1(17).

[38] NER, cl. 6.8.2(d1).

[39] This will occur pursuant to obligations in cl. 6.18.2 and cl. 6.18.8 of the NER.

While demand tariffs remain a viable cost reflective tariff preferred by some customers and retailers, we consider the potential impact on small customers of *default* demand tariffs could be unacceptably high for the 2025–30 period, as it would be the first exposure of many to cost reflective tariffs and customers typically find demand tariffs more difficult to understand and therefore to respond to, relative to time-of-use tariffs. We considered this in the context of widespread cost of living pressures occurring at the same time as the anticipated accelerated smart meter roll-out which would see more customers having smart meters installed (and being assigned to cost reflective network tariffs).

Ergon Energy is also required to make the following changes to its revised tariff structure statement to achieve compliance with the NER pricing principles and contribute to the achievement of the NEO:

- include further information on the proposed contingent tariff adjustments to remove obsolete tariffs within the 2025–30 period
- include an explicit export tariff transition strategy, convert proposed export charges and basic export levels from demand to energy-based measurement, and include network bill impact analysis for small and large businesses proposed to face two-way pricing
- provide further detail on proposed grid-scale storage tariffs, including more detail on the proposed critical peak pricing mechanism
- offer a time-of-use tariff option for LV large business customers with demand greater than 120 kVA[40] but consumption less than 160 MWh to contribute to the achievement of the NEO, in particular to Queensland's targets for reducing Australia's greenhouse gas emissions (i.e. its net zero 2050 target and its Zero Emission Vehicle Strategy (ZEV Strategy) 2022–2032)[41]
- include further description of control arrangements that are contained in the Queensland Electricity Connections Manual, further explanation of the relationship between the Manual and tariff structure statements, and the extent to which control arrangements influence tariff options, including the proposed new flexible load control tariff.

We also encourage Ergon Energy to consider making minor improvements in its revised tariff structure statement, for example by including additional supporting information on dynamic connections agreements for exporting customers, its Demand Small tariff for large LV businesses, bill impact analysis and the number of customers affected by withdrawn tariffs.

In Attachment 19, we describe in further detail the reasons for our decision and the changes that we consider necessary for us to approve Ergon Energy's tariff structure statement proposal, as well as the changes we encourage Ergon Energy to make. We note we have provided a combined draft decision tariff structure statement attachment for Ergon Energy and Energex.

[40] kVA = kilovolt amp.

[41] AEMC, *Emissions Targets statement under the national energy laws*, June 2024.

# 5 Metering

Smart meters are foundational to a more connected, modern, and efficient energy system and one mechanism to ensure that future technologies, services, and innovations are supported. Throughout the 2025–30 regulatory determinations, we signalled that we would consider the implications of the AEMC's final decision on the transitioning of legacy meters. This includes different classification and/or price/revenue control settings for legacy metering services.

The key objective of the AEMC's final decision, released in August 2023, is to target a 100% replacement of distribution network owned accumulation meters with smart meters offered by other parties by 30 June 2030.[42] Our draft decision considers this constitutes a material change in circumstances, which would justify departure from the classification of legacy metering services in the Framework and approach.

Our draft decision accepts Ergon Energy's proposal to reclassify legacy metering as standard control services and the application of a revenue cap. We consider this is the most appropriate outcome because it is consistent with our guidance note and provides an outcome that is in the long term interests of consumers.[43] It ensures no customer is worse off than other customers as a result of when their legacy meter is replaced. By comparison, customers whose meters are replaced later in the replacement program would incur inequitably higher prices than those whose meters are replaced earlier under the approach in the final F&A.

We also consider it appropriate to apply the same regulatory settings to the regulated MI-C network and include the recovery of MI-C metering services with that of Ergon Energy's NEM-connected customers. This ensures consistency in application, as well as equitable treatment and costs regardless of location. Managing separate asset bases or maintaining MI-C network metering services as ACS would increase administrative burden.

In addition, our draft decision accepts Ergon Energy's proposal for no new capex, to apply accelerated depreciation to the regulated asset base and cost recovery approach (a flat per customer charge to low voltage customers). However, our draft decision is to not accept Ergon Energy's proposal overall because we substitute alternate estimates for forecast metering opex (applying a bottom-up approach) and subsequently the annual revenue requirement due to updated inputs. The reasons for our decision are discussed in detail at attachment 20 and outcomes relating to service classification to support the AEMC's intention are discussed at attachment 13.

42 AEMC, *Final Report: Review of the regulatory framework for metering services*, August 2023.

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

# 6 Constituent decisions

Our draft decision on Ergon Energy's distribution determination for the 2025–30 regulatory control period includes the following constituent decision components:

| Constituent component |
| --- |
| In accordance with clause 6.12.1(1) of the NER, the AER's draft decision is that the classification of services set out in Attachment 13 will apply to Ergon Energy for the 2025–30 regulatory control period, for the reasons set out in that attachment. |
| In accordance with clause 6.12.1(2)(i) of the NER, the AER's draft decision is to not approve the annual revenue requirement set out in Ergon Energy's building block proposal. Our draft decision on Ergon Energy's annual revenue requirement for standard control services other than legacy metering services (main standard control services) for each year of the 2025–30 regulatory control period is set out in Attachment 1.<br><br>Our draft decision on Ergon Energy's legacy metering annual revenue requirement for each year of the 2025–30 regulatory control period is set out in Attachment 20. |
| In accordance with clause 6.12.1(2)(ii) of the NER, the AER's draft decision is to approve Ergon Energy's proposal that the regulatory control period will commence on 1 July 2025. Also in accordance with clause 6.12.1(2)(ii) of the NER, the AER's draft decision is to approve Ergon Energy's proposal that the length of the regulatory control period will be five years from 1 July 2025 to 30 June 2030. |
| The AER did not receive a request for an asset exemption under clause 6.4B.1(a)(1) and therefore has not made a decision in accordance with clause 6.12.1(2A) of the NER. |
| In accordance with clause 6.12.1(3)(ii) and acting in accordance with clause 6.5.7(d) of the NER, the AER's draft decision is to not accept Ergon Energy's proposed total forecast net capital expenditure.<br><br>For main standard control services, we do not accept Ergon Energy's proposed capital expenditure of $5,704.8 million ($2024–25). Our draft decision therefore includes an alternative estimate of Ergon Energy's total forecast net capex for the 2025–30 regulatory control period of $4,188.1 million ($2024–25). The reasons for our draft decision are set out in Attachment 5.<br><br>For metering, we accept Ergon Energy's proposal forecast of no capex. This is set out in Attachment 20. |
| In accordance with clause 6.12.1(4)(ii) and acting in accordance with clause 6.5.6(d) of the NER, the AER's draft decision is to not accept Ergon Energy's proposed total forecast operating expenditure. |

**Constituent component**

For main standard control services, we accept Ergon Energy’s proposed total forecast operating expenditure, inclusive of debt raising costs and exclusive of DMIAM of $2,379.1 million ($2024–25). The reasons for our draft decision are set out in Attachment 6.

For metering, we do not accept Ergon Energy’s proposed total forecast operating expenditure forecast of $118.7 million ($2024–25) and replace it with a forecast of $110.5 million ($2024–25). This is set out in Attachment 20.

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Ergon Energy did not propose any contingent projects and therefore the AER has not made a decision under clause 6.12.1(4A) of the NER.

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In accordance with clause 6.12.1(5) of the NER and the 2022 Rate of Return Instrument, the AER's draft decision is that the allowed rate of return for the 2025–26 regulatory year is 6.04% (nominal vanilla) for the reasons set out in Attachment 3. The rate of return for the remaining regulatory years of the 2025–30 period will be updated annually because our decision is to apply a trailing average portfolio approach to estimating debt which incorporates annual updating of the allowed return on debt.

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In accordance with clause 6.12.1(5A) of the NER and the 2022 Rate of Return Instrument, the AER's draft decision on the value of imputation credits as referred to in clause 6.5.3 is to adopt a value of 0.57. The reasons for our draft decision are set out in Attachment 3.

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In accordance with clause 6.12.1(6) of the NER, and acting in accordance with clause 6.5.1 and schedule 6.2 of the NER, the AER's draft decision on Ergon Energy’s main standard control services regulatory asset base as at 1 July 2025 is $15,566.1 million ($ nominal). The reasons for our draft decision are set out in Attachment 2.

The AER’s draft decision on Ergon Energy’s metering regulatory asset base as at 1 July 2025 is $42.0 million ($ nominal). This is discussed in Attachment 20.

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In accordance with clause 6.12.1(7) of the NER, the AER's draft decision on Ergon Energy’s estimated cost of corporate income tax for main standard control services is $69.8 million ($ nominal) for the 2025–30 regulatory control period. The reasons for our draft decision are set out in Attachment 7 and the amount for each regulatory year of the 2025–30 regulatory control period is set out in the table below.

| ($ million, nominal) | 2025–26 | 2026–27 | 2027–28 | 2028–29 | 2029–30 | Total |
|---|---|---|---|---|---|---|
| Tax payable | 11.5 | 27.6 | 32.4 | 42.8 | 48.2 | 162.4 |
| *Less:* value of imputation credits | 6.5 | 15.7 | 18.5 | 24.4 | 27.5 | 92.6 |
| **Net cost of corporate income tax** | **4.9** | **11.9** | **13.9** | **18.4** | **20.7** | **69.8** |

The AER’s draft decision on Ergon Energy’s cost of corporate income tax for legacy metering is $0.0 million ($ nominal) for the 2025–30 regulatory control period.

| Constituent component |
| --- |
| In accordance with clause 6.12.1(8) of the NER, the AER's draft decision is to not approve the depreciation schedules submitted by Ergon Energy.<br><br>For main standard control services, our draft decision substitutes alternative depreciation schedules that accord with clause 6.5.5(b). The regulatory depreciation amount approved in this draft decision is $1,263.7 million ($ nominal) for the 2025–30 regulatory control period. The reasons for our draft decision are set out in Attachment 4.<br><br>For legacy metering, our draft decision substitutes alternative schedules amounting to regulatory depreciation for the 2025–30 regulatory control period of $42.0 million ($ nominal). This is discussed in Attachment 20. |
| In accordance with clause 6.12.1(9) of the NER the AER makes the following draft decisions on how any applicable efficiency benefit sharing scheme (EBSS), capital expenditure sharing scheme (CESS), export services incentive scheme (ESIS), service target performance incentive scheme (STPIS), demand management incentive scheme (DMIS), demand management innovation allowance mechanism (DMIAM) or small-scale incentive scheme (customer service incentive scheme) is to apply:<br><br>• We will apply version 2 of the EBSS to Ergon Energy in the 2025–30 regulatory control period. Our reasons are set out in Attachment 8.<br>• We will apply the CESS as set out in the 2023 Capital Expenditure Incentives Guideline to Ergon Energy in the 2025–30 regulatory control period. Our reasons are set out in Attachment 9.<br>• We will not apply the ESIS for the 2025–30 regulatory control period.<br>• We will apply our STPIS Version 2.0 to Ergon Energy for the 2025–30 regulatory control period. Our reasons are set out in Attachment 10.<br>• We will apply the DMIS and DMIAM to Ergon Energy for the 2025–30 regulatory control period. Our reasons are set out in Attachment 11.<br>• We will not apply the customer service incentive scheme (CSIS) to Ergon Energy for the 2025–30 regulatory control period. Our reasons are set out in Attachment 10 |
| In accordance with clause 6.12.1(10) of the NER, the AER's draft decision is that all other appropriate amounts, values and inputs are as set out in this draft determination including attachments. |
| In accordance with clause 6.12.1(11) of the NER and our framework and approach paper, the AER's draft decision on the form of control mechanisms (including the X factor) for standard control services is a revenue cap. The revenue cap for Ergon Energy for any given regulatory year is the total annual revenue calculated using the formula in Attachment 14, which includes any adjustment required to move the Distribution Use of Service (DUoS) and metering unders and overs accounts to zero. The reasons for our draft decision are set out in Attachment 14. |

| Constituent component |
| --- |
| In accordance with clause 6.12.1(12) of the NER and our framework and approach paper, the AER's draft decision on the form of the control mechanism for alternative control services is to apply price caps for all alternative control services. The reasons for our draft decision are set out in Attachment 14. |
| In accordance with clause 6.12.1(13) of the NER, to demonstrate compliance with its distribution determination, the AER's draft decision is that Ergon Energy must maintain both DUoS and metering unders and overs mechanisms. It must provide information on these mechanisms to us in its annual pricing proposal. The reasons for our draft decision are set out in Attachment 14. |
| In accordance with clause 6.12.1(14) of the NER the AER's draft decision is to apply the following nominated pass through events to Ergon Energy for the 2025–30 regulatory control period in accordance with clause 6.5.10:<br>• Insurance coverage event<br>• Insurer's credit risk event<br>• Terrorism event<br>• Natural disaster event<br>These events have the definitions set out in Attachment 15 of the draft decision. Our reasons for this constituent decision are also set out in that attachment. |
| In accordance with clause 6.12.1(14A) of the NER, the AER's draft decision is to not approve the tariff structure statement proposed by Ergon Energy. The reasons for our draft decision are set out in Attachment 19. |
| In accordance with clause 6.12.1(15) of the NER, the AER's draft decision is that the negotiating framework as proposed by Ergon Energy will apply for the 2025–30 regulatory control period. The reasons for our draft decision are set out in Attachment 17. |
| In accordance with clause 6.12.1(16) of the NER, the AER's draft decision is to apply the negotiated distribution services criteria published in February 2024 to Ergon Energy. The reasons for our draft decision are set out in Attachment 17. |
| In accordance with clause 6.12.1(17) of the NER, the AER's draft decision on the procedures for assigning retail customers to tariff classes for Ergon Energy is set out in Attachment 19. |
| In accordance with clause 6.12.1(18) of the NER, the AER's draft decision is that the depreciation approach to be used to establish the RAB at the commencement of Ergon |

| Constituent component |
| --- |
| Energy’s regulatory control period as at 1 July 2030 is to be based on forecast capex. The reasons for our draft decision are set out in Attachment 2. |
| In accordance with clause 6.12.1(19) of the NER, the AER's draft decision on how Ergon Energy is to report to the AER on its recovery of designated pricing proposal charges and account for the under and over recovery of designated pricing proposal charges is the unders and overs mechanism. It must provide information on this mechanism to us in its annual pricing proposal. The reasons for our draft decision are set out in Attachment 14. |
| In accordance with clause 6.12.1(20) of the NER, the AER's draft decision on how Ergon Energy is to report to the AER on its recovery of jurisdictional scheme amounts and account for the under and over recovery of jurisdictional scheme amounts is the unders and overs mechanism. It must provide information on this mechanism to us in its annual pricing proposal. The reasons for our draft decision are set out in Attachment 14. |
| In accordance with clause 6.12.1(21) of the NER, the AER's draft decision is to approve the connection policy proposed by Ergon Energy. Our reasons are set out in Attachment 18. |

# 7 List of submissions

We received 17 submissions in response to Ergon Energy 2025–30 distribution revenue proposal. These are listed below.[44]

| Submissions from |
|---|
| AER Consumer Challenge Panel (CCP) Sub-Panel 30 (CCP30) |
| Amanda Pummer |
| Electric Vehicle Council |
| Electrical Safety Office (ESO) |
| Energy2 |
| EQL Reset Reference Group (Engagement Report) |
| EQL Reset Reference Group |
| Evie Networks |
| Firm Power |
| Master Electricians Australia |
| Mirabou Energy |
| Network Energy Services |
| Origin Energy |
| Jack |
| Queensland Farmers' Federation (QFF) |
| Tesla |
| Zero Emissions 4075 Inc. |

44 Submissions are available on the AER website at https://www.aer.gov.au/industry/registers/determinations/ergon-energy-determination-2025-30/proposal#submissions

# Shortened forms

| Terms | Definition |
|---|---|
| ACS | alternative control services |
| AEMC | Australian Energy Market Commission |
| AEMO | Australian Energy Market Operator |
| AER | Australian Energy Regulator |
| augex | augmentation expenditure |
| Capex | capital expenditure |
| CCP30 | Consumer Challenge Panel, sub-panel 30 |
| CER | Consumer Energy Resources |
| CESS | capital expenditure sharing scheme |
| CSIS | customer service incentive scheme |
| DER | Distributed Energy Resources |
| DMIAM | demand management innovation allowance mechanism |
| DMIS | demand management incentive scheme |
| DNSP or distributor | Distribution Network Service Provider |
| DUoS | Distribution Use of System Charges |
| EBSS | efficiency benefit sharing scheme |
| ECA | Energy Consumers Australia |
| ESB | Energy Security Board |
| ESO | Electrical Safety Office |
| F&A | framework and approach |
| ICT | information and communication technologies |
| NEL | National Electricity Laws |
| NEM | National Electricity Market |
| NEO | National Electricity Objectives |
| NER | National Electricity Rules |
| opex | operating expenditure |
| RAB | regulated asset base |
| repex | replacement expenditure |
| RRG | Ergon Energy and Energex’s Reset Reference Group |
| SCS | standard control service |
| STPIS | service target performance incentive scheme |