Final Decision

Ergon Energy Electricity Distribution Determination 2025 to 2030

(1 July 2025 to 30 June 2030)

Overview

April 2025

AUSTRALIAN ENERGY REGULATOR

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Amendment record

Version	Date	Pages
1	30 April 2025	44

List of attachments

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

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

The final decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

Attachment 13 – Classification of services

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Attachment 19 – Tariff structure statement

Attachment 20 – Metering services

Executive summary

The Australian Energy Regulator (AER) is responsible for the economic regulation of electricity distribution and transmission systems in all states and territories except Western Australia.

We exist 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 we transition to net zero emissions.

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).

This final decision relates to Ergon Energy. Each constituent component of our distribution determination is set out in section 6. The final decision will be implemented from 1 July 2025 and reflected in 2025–26 prices.

The regulatory framework guides our decisions in the long term interests of consumers

The National Electricity Law (NEL) and National Electricity Rules (NER) provide the regulatory framework under which we determine the revenue requirement for distribution and transmission businesses.

The NEL requires that we exercise our economic regulatory functions in a manner that promotes efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers. We make these decisions having regard to price, quality, safety, reliability and security of supply, and targets to reduce emissions. This is referred to as the National Electricity Objective or the NEO.[1] We have also issued guidance about an interim value of emissions reduction,[2] which we must comply with in considering or applying the NEO.[3]

The central component of Ergon Energy's proposal is the revenue that it recovers from consumers over the next 5 years to 2030. We have assessed this by considering the constituent components of Ergon Energy's proposal, including capital expenditure (capex), operating expenditure (opex) and the tariff structure statement to ensure it complies with the NER.

We have substituted alternative forecasts where we assess Ergon Energy's proposal does not meet certain criteria in the NER. In other instances, we have substituted alternative forecasts to update for input assumptions such as for inflation. We have made our final decision such that we achieve the NEO, in the long term interests of consumers.

Our final decision provides Ergon Energy with an allowed revenue which it can recover from consumers over 2025–30. Ergon Energy must decide how best to use this revenue in

1 The full statement of the NEO is at section 7 of the NEL.

2 AER, *Valuing emissions reduction, Final guidance and explanatory statement*, May 2024.

3 NEL, schedule 2, clause 42.

providing distribution services that fulfill its obligations, including to maintain the safety and reliability of its network. Our regulatory framework includes incentive mechanisms that are designed to encourage Ergon Energy to operate efficiently and prudently in the long-term interests of consumers.

We are focused on efficient investment to deliver a safe and reliable network that meets consumer needs

Our final decisions for the 2025–30 resets have been made against the backdrop of rising network expenditure. Our performance report shows that actual combined capex across the NEM increased by 19.7% in real terms in 2023.[4] We have also observed increases in forecast capex and opex in recent revenue proposals.

The increase in proposed expenditure has been driven by a range of factors that affect the reliable and secure supply of electricity. This includes the steady ageing of assets, increases in the cost of inputs, managing new sources of electricity demand and the integration of consumer energy resources, such as solar panels. We have also seen a higher incidence of extreme weather events and an increase in the risk of cyber-related activity. Network costs are also increasing due to economy-wide factors of a higher interest rate and a higher inflationary environment. Compared with when we made our determination for Ergon Energy 5 years ago, the cost of capital has increased from 4.73% to 6.09% and inflation has increased from 2.27% to 2.72%. These are key inputs in this regulatory determination.

In assessing proposals by network businesses, we continue to seek the balance of affordability, with efficient and prudent investment required to support the energy transition, and to address important emerging issues such as network cybersecurity, climate resilience and integration of CER.

We also expect electricity network businesses to submit proposals that clearly demonstrate how they plan to meet the challenges of a higher cost environment over the regulatory period in a way that achieves an affordable, stable, secure and reliable supply of energy in the long-term interests of consumers. We want to see network businesses utilising the revenue determination process to propose tariff design, incentive structures and efficient and prudent expenditure that achieves the NEO.

- We want to see a continued commitment by networks toward cost-reflective tariff reform aimed at reducing the amount of network investment required to provide sufficient network capacity and stability during peak demand and export periods. In developing cost reflective tariffs, network businesses should be mindful of how it would work in practice – cost reflective tariffs that are faced by retailers need to be both efficient and readily understood to be adopted widely in the community.
- Incentive mechanisms are a key component of our incentive-based regulatory framework. They create an impetus to drive efficient and prudent capex and opex and a desirable level of customer service. Moving away from, or proposing adjustments to incentive mechanisms, where the businesses may be at risk of penalties, must be canvassed with consumers who stand to be most affected by these changes.
- A key component of achieving an efficient and prudent plan for consumers is to be disciplined in how existing assets are used before building more. As any network

[4] AER, *2024 Electricity and gas networks performance report*, September 2024, p. 5

infrastructure investment will be paid for by consumers, it is important that businesses effectively utilise their existing infrastructure for distribution services, looking for non-network solutions and avoiding any unnecessary future infrastructure investment.

Consumer needs should be a key focus of the DNSPs' regulatory proposals. Network businesses should engage collaboratively with consumers on key aspects of the proposal that will affect consumers, including capex and opex. To assist, we introduced the Better Resets Handbook in 2021 (the Handbook), to further guide businesses to engage and design proposals that meet consumer needs through the energy transition.[5]

At the draft decision we found that Ergon Energy's engagement fell short of what is expected under the Handbook and of the standard that we have observed from a range of other recent electricity distribution resets. We encouraged Ergon Energy to conduct a more consultative process on key elements of our draft decision to inform the revised proposal.

Reflections on Ergon Energy's consumer engagement and revenue proposals

Ergon Energy's stakeholder engagement plan was well targeted and set up across a number of forums to provide meaningful input into the revised proposal. Ergon Energy engaged with its Voice of Customer Panel, Customer and Community Council and Network Pricing Working Group to obtain consumer views on the AER's draft decisions on capital investment, network tariffs and the customer service incentive scheme (CSIS).

However, Ergon Energy presented an unbalanced picture to consumer panels regarding the AER's draft decisions on capex and some tariff elements. It was suggested our draft decision on capex would lead to worsening reliability and compromise safety goals and implied the two-way tariff proposal was rejected by the AER and encouraged consumers to support postponing its implementation. We also note that Ergon Energy did not consult on the significant changes in opex and the efficiency benefit sharing scheme beyond informing its Reset Reference Group at a late stage in the process.

A number of submissions made on our draft decision and Ergon Energy's revised proposal noted that priority should be given to affordability in considering forecast expenditure in light of the increased cost of living. Despite these concerns, Ergon Energy's revised proposal did not make any major adjustments to its approach to affordability, and had asked for required revenue that was $169 million higher than its initial proposal.

In our draft decision, we noted that Ergon Energy's proposal lacked sufficient supporting material to satisfy us that its proposed capex reasonably reflected the capex criteria. This included concerns regarding the quality of the data provided, including for its historical pole data. Ergon Energy provided additional information at the revised proposal that has allowed us to undertake a deeper analysis of Ergon Energy's capex forecasts. However, we note that the late submission of information, including around critical data about its low density poles, constrained the assessment process.

The revised proposal included a number of late changes that were not canvassed with consumers. We understand there may be some instances where late changes may be required, for example, to adjust the tariff structure statement so that changes can be

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

incorporated readily by retailers. However, there were a number of instances where changes proposed by Ergon Energy at the revised proposal stage did not fall into this category and were not properly canvassed with consumer groups. These include the significant increase in opex, the proposal to remove the efficiency benefit sharing scheme, and several late proposals to the tariff structure statement. We note that revised proposals should be focused on addressing matters raised by our draft decision (NER clause 6.10.3 (b)).

Our final decision on Ergon Energy's revised proposal

Our final decision is that Ergon Energy can recover $8,579.5 million ($ nominal, smoothed) in main standard control services (SCS) revenue from its customers for the 2025–30 period. This is $112.2 million (1.3%) less than Ergon Energy's revised proposal, and $213.6 million (2.6%) more than our draft decision. Our final decision includes additional capex compared to our draft decision to address the safety and reliability of the network.

The decrease in overall revenue in this final decision compared to Ergon Energy's revised proposal is mainly driven by our reductions to forecast opex and capex and our revenue adjustments. The final decision is nevertheless higher than our draft decision because we have approved higher amounts of opex and capex compared to our draft decision. It is also the result of updated input assumptions such as a lower expected inflation rate, which increases the value of regulatory depreciation and higher rate of return, increasing the return on capital.

Our final decision revenue is $2,570.8 million or 42.8% more than Ergon Energy's allowed revenue in the 2020–25 period in nominal terms.[6] We estimate that approximately 57% of the increase from the 2020–25 period is driven by higher inflation and interest rates. The other 43% of the increase is driven by higher capital and operating expenditure.

Our bill impacts for Ergon Energy adopt those calculated in our final decision for Energex because 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. We therefore estimate an average increase of $48 per annum to the typical electricity bill for Ergon Energy's residential customers over the 2025–30 period. For small business customers, the impact would be an average increase of $97 per annum.

Capital expenditure

We are satisfied that our alternative total capex forecast of $4,410.7 million is reasonable and sufficient for Ergon Energy to achieve the capex objectives, especially to maintain the safety and reliability of its network.

In coming to our decision, we have been cognisant of the safety and reliability risks faced by Ergon Energy, and therefore have accepted Ergon Energy's volume forecasts for a number of programs where safety and reliability risks have been the primary driver. For instance, we have accepted Ergon Energy's volume forecasts for its clearance volumes as well as its low density 3kN poles volumes which provides funding to address the safety and reliability risks associated with these assets.

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6 Adjusting for the impact of inflation, our final decision revenue is 17.1% higher than Ergon Energy's allowed revenue for the 2020–25 period.

However, we have not accepted Ergon Energy's forecast where we have not been provided evidence that demonstrates an overall benefit to consumers. For instance, we have not accepted expenditure for inefficient opportunistic replacement, as it results in the unnecessary replacement of assets.

The additional information provided to us by Ergon Energy in its revised proposal has allowed us to conduct a deeper analysis in deriving our alternative forecast, rather than relying on top-down assessment methods such as benchmarking. It has provided the justification needed for us to approve a higher level of forecast expenditure tied to maintaining the safety and reliability of the network.

Ex-post review into Ergon Energy's capex overspend

We conducted an ex-post review of Ergon Energy's capital expenditure from 2018 to 2023. Our draft decision recommended a 50% reduction in capex over this period to be rolled into the opening RAB at 1 July 2025. Ergon Energy accepted our draft decision. 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 acknowledge Ergon Energy's decision accepted the AER draft decision on Ergon Energy's ex-post capex to address affordability concerns. However, we note that Ergon Energy did not accept our reduction to the volume of pole replacement in our ex-post decision. We also observe that estimated capex in 2024 and 2025 has continued to rise.

We reiterate our concerns made at the draft decision, about Ergon Energy's asset management practices, particularly its practice of retrospectively applying new standards to existing assets, and its approach to opportunistically replacing pole top structures and service lines when replacing poles. These practices are contributing to inefficient expenditure on the network.

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 consumer bills.

Operating expenditure

Ergon Energy's revised revenue proposal sought a $183.9 million (or 7.7%) increase in opex due to higher audited actual data for the nominated base year 2023–24. We note that this is a significant increase from the initial proposal, which Ergon Energy ascribed to one off storm costs and labour cost increases primarily driven by a new enterprise agreement.

Our final decision is to not accept Ergon Energy's revised opex proposal and substitute our alternative estimate of $2,331.1 million. Our alternative estimate uses 2022–23 as the base year rather than 2023–24 as proposed by Ergon Energy. This is because our analysis shows that 2022–23 is not materially inefficient and does not include significant one-off costs, and so most reasonably reflects the level of prudent and efficient costs Ergon Energy will need to deliver the required services over the next regulatory period. Our final decision for opex is $231.8 million (9.0%) less than Ergon Energy's revised proposal and $48.0 million (2.0%) higher than Ergon Energy's initial proposal, which we accepted in our draft decision.

Ergon Energy, in its revised proposal, also proposed that we do not apply the efficiency benefit sharing scheme penalties accrued from the current period, and that we suspend the scheme in the next regulatory period. This was made on the basis that the AER would make an efficiency adjustment to Ergon Energy's 2023–24 base year opex, and that also applying the efficiency benefit sharing scheme penalties would penalise the business twice.

As we have used Ergon's actual 2022–23 opex as the base year to forecast total opex, and have not applied an efficiency adjustment, we have applied Ergon Energy's efficiency benefit sharing scheme penalties calculated using the 2022–23 base year, and applied the scheme in the next regulatory period. Provided we forecast Ergon's future opex using its revealed costs in the 2025–30 period, this will ensure that any efficiency gains that Ergon achieves will lead to lower future opex forecasts, and thus lower network tariffs.

Tariff structure statement

Our final decision is to require 7 amendments to Ergon Energy's tariff structure statement to enable it to be approved in accordance with the NER. These amendments relate to secondary load control tariffs, proposed dynamic price storage tariffs, the proposed movements to peak and solar soak charging windows during the 2025–30 period, section 1.1. of its tariff structure statement and logistical issues relating to moving some customers with basic meters from proposed withdrawn tariffs.

Our final decision otherwise approves many elements of Ergon Energy's proposed revised tariff structure statement. This includes Ergon Energy's response to our draft decision, to propose default time-of-use tariffs for small customers, and to reassign existing small customers to the new default time-of-use tariffs instead of demand tariffs. Ergon Energy also introduced a time-of-use tariff for large customers with peaky loads and modified its dynamic flex storage tariffs in response to our draft decision and stakeholder submissions. The changes to Ergon Energy's revised tariff structure statement complement those elements that we approved in our draft decision, for example its streamlined and simplified suite of tariffs and the introduction of solar soak charging windows (low cost periods during the middle of the day).

Ergon Energy's proposed revised tariff structure statement also included some changes from the initial tariff structure statement, to areas that were *not* in response to the draft decision, and that we have approved. For example, simplifying small business time-of-use tariffs so that they have the same structure as the residential time-of-use tariff and aligning large customer tariff variable (time-of-use and demand) charges across Ergon Energy's three pricing zones. The additional changes to the revised tariff structure statement include 3 late changes to the tariff structure statement (provided by letter on 6 February 2025).

Our final decisions do not prevent retailers from providing tariff options to consumers that suit consumer needs, including the provision of flat retail tariffs.

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 final decision.

Contents

1 Our final decision

Our final decision allows Ergon Energy to recover a total revenue of $8,750.2 million ($ nominal, smoothed) from its consumers from 1 July 2025 to 30 June 2030 which comprises: $8,579.5 million in main standard control services (SCS) revenue; and $170.7 million in metering revenue.[7]

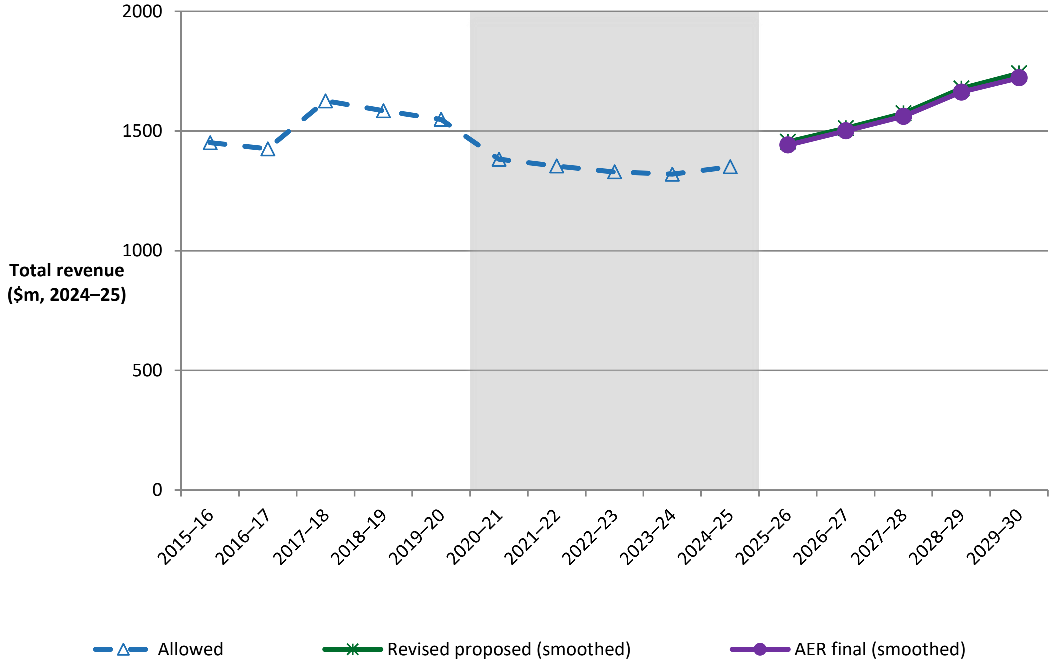
Our final decision SCS revenue is $2,570.8 million or 42.8% more than Ergon Energy's allowed revenue in the 2020–25 period in nominal terms. In the sections below we briefly outline what is driving Ergon Energy's main SCS revenue, and key differences between our final decision revenue compared to the $8,365.9 million in our draft decision, and the $8,691.7 million in Ergon Energy's revised proposal.[8]

1.1 What is driving revenue?

Revenue is driven by changes in real costs and inflation. In this section we use 'real' values that have been adjusted for the impact of inflation to compare revenue from one period to the next on a like-for-like basis.

In real terms, this final decision would allow Ergon Energy to recover $7,890.8 million ($2024–25, smoothed) over the 2025–30 period. This is 17.1% higher than our decision for the 2020–25 period. Ergon Energy's revenue over time is shown in Figure 1.

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



Source: AER analysis.

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7 This is $0.01 million more than the $170.7 million that Ergon Energy included in its revised proposal.

8 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.

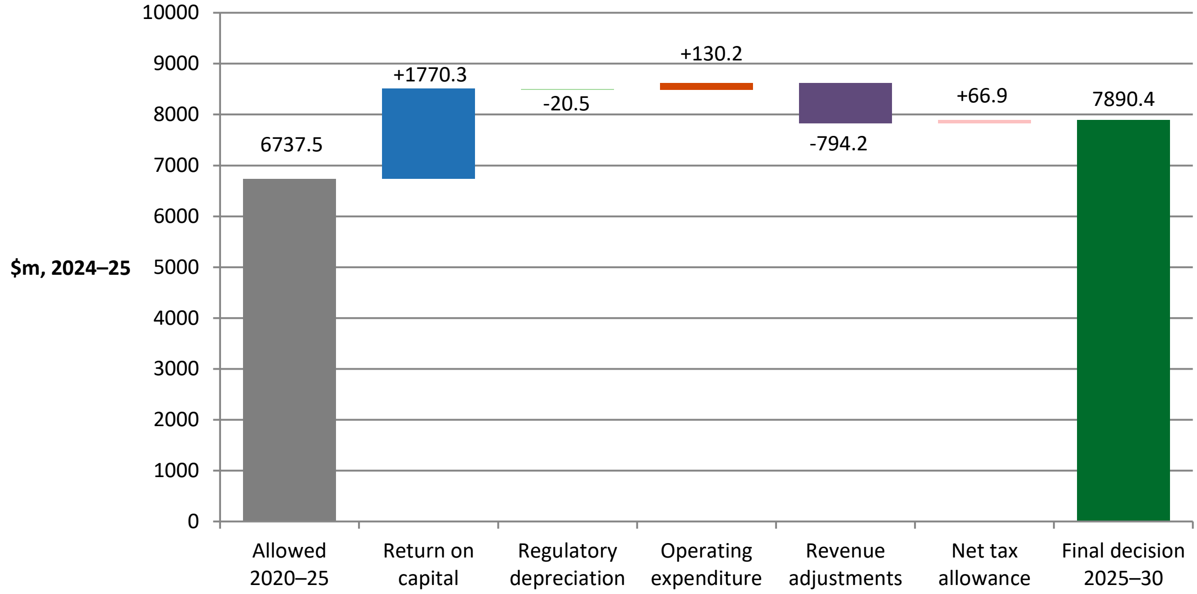
Figure 2 highlights the key drivers of the change in real terms between the revenue approved for Ergon Energy for the 2020–25 period and in this final decision for the 2025–30 period. It shows that our final decision provides for increases in revenue for:

- return on capital, which is $1,770.3 million (56.8%) higher than the 2020–25 period, driven by:
  - a higher rate of return in accordance with the 2022 *Rate of Return Instrument*
  - actual RAB growth in real terms, in the current 2020–25 period
  - higher forecast capex in the 2025–30 period
- cost of corporate income tax, which is $66.9 million higher than the 2020–25 period, primarily due to higher return on equity and regulatory depreciation determined in this final decision.
- opex (for main standard control services), which is $130.2 million (5.9%) higher than the opex forecast we approved in the 2020–25 period, driven primarily by the higher base year opex.

Figure 2 also shows that our final decision provides for a reduction in the building block for:

- revenue adjustments, which is $794.2 million lower than the 2020–25 period, mainly due to the large negative Efficiency Benefit Sharing Scheme (EBSS) and Capital Expenditure Sharing Scheme (CESS) outcomes applied in this final decision.
- return of capital (regulatory depreciation), which is $20.5 million (1.7%) lower than the 2020–25 period, driven primarily by higher indexation of the RAB.

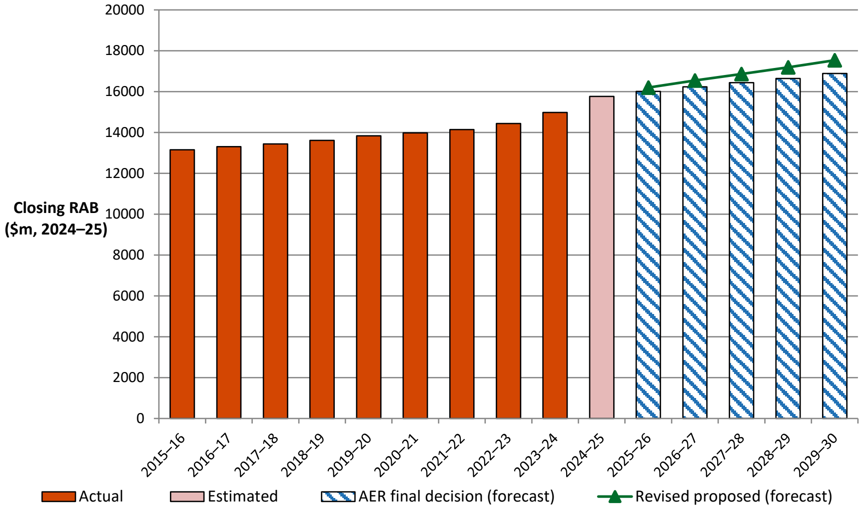
Figure 2 Changes in total revenue between 2020–25 and 2025–30 ($ million, 2024–25 unsmoothed)



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 13.9% over the 2020–25 period, our final decision is expected to result in a forecast RAB increase of $1,123.9 million (7.1%) over the 2025–30 period. An increasing real RAB reflects capex entering the RAB that exceeds forecast straight-line depreciation.

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

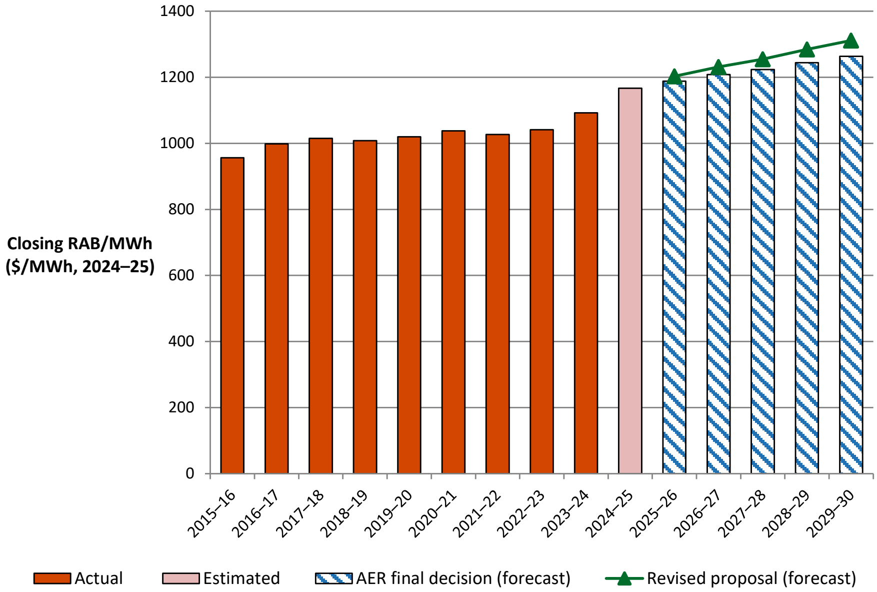


Source: AER analysis.

RAB values substantially affect a network businesses' revenue requirements, and the total costs customers ultimately pay. We expect RABs to change over time, as capital investment will depend on the network's age and technology, load characteristics, the levels of new connections and reliability and safety requirements.

Figure 4 shows that Ergon Energy's RAB per MWh is forecast to increase over 2025–30 compared to the final year of the 2020–25 period. This is based on Ergon Energy's forecast energy delivered (MWh) and could change depending on actual network utilisation. We consider efficient investment in, and efficient operation and use of, electricity services are important to minimise the required capital expenditure and the RAB.

Figure 4 Ergon Energy's RAB per energy consumption over time ($/MWh, 2024–25)



Source: AER analysis.

1.2 Key differences between our final decision and Ergon Energy's revised proposal

In our final decision, we have made amendments to core components of Ergon Energy's proposal which reduce revenue. For the 2025–30 period, the main areas of difference between our final decision and Ergon Energy's revised proposal relate to our:

- lower opex forecasts, primarily driven by our use of Ergon Energy's actual 2022–23 opex as the base year, updates to Ergon Energy's maximum demand forecasts, and not including an amount for the smart meter data step change.
- lower capex forecasts, primarily driven by reductions in repex.
- higher negative revenue adjustments, driven by our decision to apply the EBSS, which Ergon Energy proposed to not apply in its revised proposal.

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

- a higher return on capital, driven by a higher rate of return[9]
- a higher regulatory depreciation amount, driven by a lower expected inflation which reduces the indexation of the RAB.

Our final decision also includes a higher estimated cost of corporate income tax amount, driven by a higher return on equity and higher regulatory depreciation.

The reductions to forecast opex and capex, and the application of EBSS penalties in our final decision, have more than offset the increases from updated market parameters. Overall, our final decision determines a total unsmoothed revenue that is $92.1 million (1.1%) ($ nominal) lower than Ergon Energy's revised proposal.

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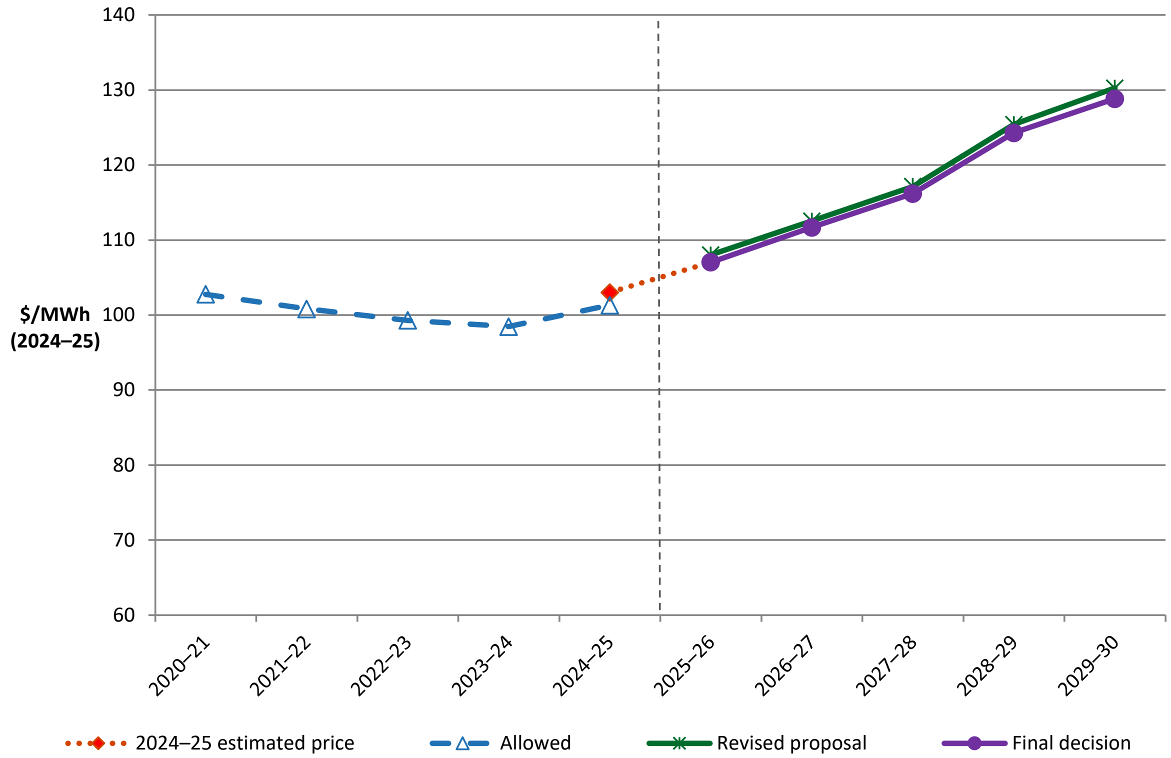
9 Average rate of return over the 2025–30 period.

1.3 Expected impact of our final decision on electricity bills

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 5 shows the modelled impact of distribution charges under this final decision and the revised proposal in real terms.

Figure 5 Change in indicative distribution charges for 2020–25 to 2025–30 ($2024–25, $/MWh)



Source: AER analysis.

The final decision is estimated to increase Ergon Energy's average distribution charges by around 25.1% in real terms by 2029–30 compared to 2024–25, or an average increase of 4.6% per annum.[10] This estimate will be subject to ongoing revenue adjustments and changes in consumer energy consumption.

Potential bill impact

Our bill impacts for Ergon Energy adopt those calculated in our final decision for Energex because 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 The average increase to indicative network charges of 4.6% ($2024–25) per annum reflects two components: 1) the final decision smoothed revenue average increase of 4.4% 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.

Distribution charges make up around 27% of Ergon Energy's residential customers' electricity bills and 26% of its small business customers' electricity bills.[11] Other components of the electricity supply chain also contribute to the prices ultimately paid by consumers. These are the cost of purchasing energy from the wholesale market, transmission network charges, environmental scheme costs and the costs and margins applied by electricity retailers.[12] These components of the bill sit outside the decision we are making here but will also continue to change throughout the period.

We estimate the impact of our final decision on the average annual electricity bill for a customer in Ergon Energy's network area, as it is today, would be: [13]

- a nominal increase of $242 (11.7%) by 2029–30, or an average of $48 per annum for a residential customer
- a nominal increase of $486 (11.4%) by 2029–30, or an average of $97 per annum for a small business customer.

The impact of our final decision on consumer bills is likely to change over the 2025–30 period. A variance in energy consumption, compared to that forecast would lead to different bill impacts.

We note that under the uniform tariff policy, the Queensland Government subsidises the cost of electricity supply to regional Queensland through Community Service Obligation payments to Ergon Energy Retail, meaning differences between the levels of Energex and Ergon Energy network tariffs do not impact customers.[14]

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 defined in the NER. They may also include additional cost pass through events proposed by Ergon Energy and approved in this final decision. The triggers we have set out for these pass through events 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. Our final decision to apply the Service Target Performance Incentive Scheme (STPIS) over the 2025–30 period (section **Error! Reference source not found.**) will also impact these charges.

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

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11 These percentages reflect the proportion that distribution charges make up for an Energex customer's bill. This is because the Queensland Government's uniform tariff policy sets retail electricity prices in Ergon Energy's distribution area in line with those in Energex's area.

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

13 Our estimated bill impact is based on our final decision for Energex. It therefore uses a typical annual electricity usage of 4,600 kWh and 10,000 kWh for residential and small business customers in Energex's network area, respectively, which applies to Ergon Energy small customers under the Queensland Government's uniform tariff policy. This is based on the 2024–25 final decision default market offer.

14 Queensland Competition Authority, *Final determination – Regulated retail electricity prices in regional Queensland for 2024–25,* June 2024, p. 11.

expectations. We introduced guidance on our expectations for consumer engagement to network businesses in the Handbook in December 2021.

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 decisions.

1.4.1 Ergon Energy's engagement

In our draft decision we highlighted that Ergon Energy's engagement fell short of what is expected under the Handbook and of the standard that we have seen from a range of 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. At the draft decision, we encouraged a more consultative process on key elements of our draft decision to inform the revised proposal.[15]

Following the draft decision, we observed that Ergon Energy's stakeholder engagement plan was well targeted and set up across a number of forums to provide meaningful input into the revised proposal. Ergon Energy engaged with its Voice of Customer Panel, Customer and Community Council and Network Pricing Working Group to obtain consumer views on the AER's draft decisions on capital investment, network tariffs and the customer service incentive scheme (CSIS), and to gain support for the direction of their revised proposal.

However, the execution of some aspects of the engagement has weakened the veracity of some of the conclusions. Ergon Energy presented an unbalanced picture regarding AER's draft decisions on capex and some tariff elements in their engagement with their customer panels. It was suggested our draft decision on capex would lead to worsening reliability and compromise safety goals and implied the two-way tariff proposal was rejected by the AER and encouraged consumers to support postponing its implementation. Energy Queensland's Reset Reference Group (RRG) also expressed the view that Ergon Energy's characterisation of the AER's capex draft decision was not balanced.[16]

Ergon Energy did not fully take on board the issue of affordability in its revised proposal, despite it being a key issue raised by a number of stakeholders. We note that Ergon Energy proposed a 1% efficiency and productivity adjustment for opex that goes beyond our standard approach of 0.5%, and that Ergon Energy accepted our ex-post capex decision on the repex overspend based on affordability grounds. Nevertheless, we would have welcomed further consideration of this issue to address stakeholder feedback and to lower bills for consumers.

We encourage Ergon Energy to improve its consumer engagement over this regulatory period, and particularly for the next regulatory proposal. Submissions by our CCP30 and the

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15 AER, *Draft Decision - Overview - Ergon Energy - 2025-30 Distribution revenue proposal*, September 2024, p. 6.

16 EQL Reset Reference Group, *Submission on Ergon Energy's revised proposal and draft decision 2025-30*, January 2025, pp. 12-13.

networks' RRG[17] have made recommendations for improvements, the key being to engage collaboratively with consumers on components of the revenue proposal that have significant implications for consumers – including capex and opex and incentive mechanisms such as the EBSS.

1.4.2 What we've heard from stakeholders on our draft decision and Ergon Energy's revised proposal

We called for submissions on our draft decision and Ergon Energy's revised proposal. We received 12 submissions for Ergon Energy. The submissions highlighted concerns including about rising costs, limited customer engagement, and the need for clearer pricing structures that evolve with consumer needs and support the clean energy transition.

The CCP30 acknowledged Ergon Energy actively engaged with consumers, particularly through the RRG, whose feedback was credible and well-researched. However, its engagement on critical issues for consumers was limited.

> *[The CCP30] maintain their position that when it comes to the building blocks of the required revenue, Ergon (and Energex, in that case) were not willing to engage in detail or consider consumer feedback that would 'move the needle' on the expenditure categories, preferring to focus on justifying their current position and relying on broad (and somewhat guided) discussions on service / cost balance.*[18]

The CCP30 also observed that Ergon Energy's discussion on affordability was largely tied to exploring its tariffs and tariff structures, with little focus on how the increased capital investment or a revision to the base year opex would impact customer costs or what alternatives existed. CCP30 recommended greater transparency in presenting key changes between the Proposal, Draft Decision, and Revised Proposal would have helped build consumer trust and support. [19]

The RRG acknowledged Ergon Energy's improvement in engagement and its collaborative approach during Phase 5, though effectiveness varied across groups. The RRG observed that early interactions with the Voice of Customer Forum were constructive, but the post-Draft Decision forum failed to provide credible customer support for Ergon Energy's proposed capital expenditure program. In critique of our draft decision, the RRG stated that members of the Network Pricing Working Group (NPWG) were disappointed that their preferences were not reflected in the Draft Decision.[20] We discuss this further in section 4.

Of the 12 submissions, 11 addressed tariff issues. Attachment 19 provides a summary of stakeholder submissions on tariffs and discusses how we have considered these in our final decision.

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[17] EQL Reset Reference Group, *Submission on Ergon Energy's revised proposal and draft decision 2025-30*, January 2025, p. 19.

[18] CCP30, *Submission on Ergon Energy's revised proposal and draft decision 2025-30*, January 2025, p. 12.

[19] CCP30, *Submission on Ergon Energy's revised proposal and draft decision 2025-30*, January 2025, pp. 15-16.

[20] EQL Reset Reference Group, *Submission on Ergon Energy's revised proposal and draft decision 2025-30*, January 2025, p. 3.

Stakeholders also provided a range of feedback that included support for CER and community batteries. Other stakeholders provided views on the level of capex including augmentation expenditure. We have considered stakeholder feedback in coming to our final decision and our consideration of stakeholder feedback on these range of issues is reflected in the relevant attachments.

2 Key components of our final decision

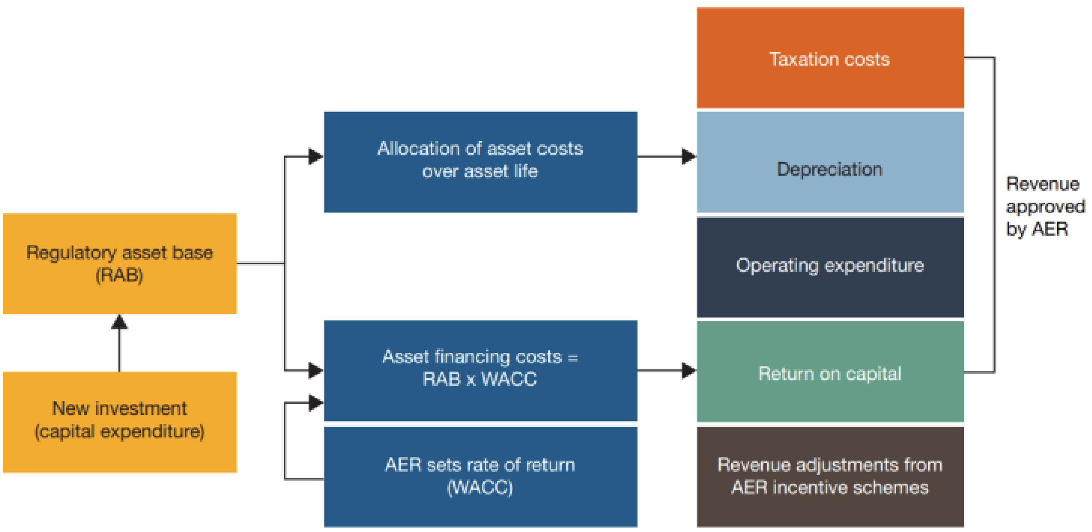
Building block approach

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 6):

- 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 6 The building block model to forecast network revenue



Source: AER.

Following the Australian Energy Market Commission (AEMC) 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 5.1.

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 final decision is based on main standard control services, without the inclusion of metering.

Revenue smoothing

Our final 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 final 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.[21]

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 final decision, we approved lower revenues than those in Ergon Energy's revised proposal. This is mainly driven by our reductions to Ergon Energy's forecast capex and forecast opex, and the higher negative revenue adjustments. The decrease in revenue has been partly offset by external economic factors reflected in a higher rate of return, which increases the return on capital, and lower expected inflation, which increases regulatory depreciation by reducing the indexation on the RAB.

On the other hand, our final 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. As part of this, we have adopted Ergon Energy's proposed adjustment of the revenue smoothing profile to account for the impact of the expiry of the Queensland Government's Solar Bonus Scheme from 1 July 2028.[22] Our final decision results in an initial increase of 6.4% (nominal) to the expected revenue in 2025–26, followed by average annual increases of 6.9% for the next 2 years (2026–27 and 2027–28), then increases of 9.4% in 2028–29 and 6.4% in 2029–30. The larger increase in 2028–29 distribution revenue will be partially offset at the annual

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21 Our final 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.

22 Consistent with Ergon Energy's revised proposal, our final decision revenue smoothing also accounts for the impact of revenue from the introduction of the Electrical Safety Office (ESO) jurisdictional scheme which will begin in the first year of the 2025–30 period.

pricing stage by the reduction in jurisdictional scheme revenue from the expiry of the Solar Bonus Scheme.

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 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.

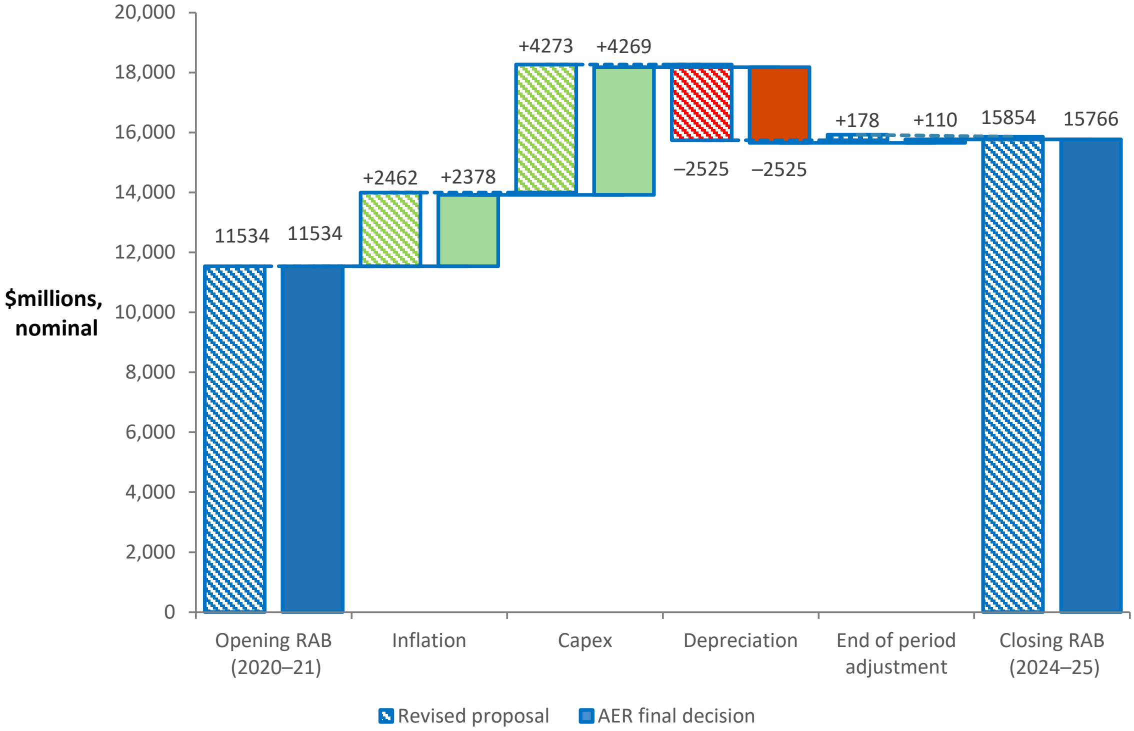
For this final decision, we have determined an opening RAB value of $15,766.3 million ($ nominal) as at 1 July 2025. This value is $88.0 million (0.6%) lower than Ergon Energy's revised proposal opening RAB value of $15,854.3 million. This reduction is largely due to the updates we made to the consumer price index (CPI) input for 2024–25 to reflect the actual outcome in the roll forward model (RFM). Figure 7 shows the key drivers ($ nominal) of the change in Ergon Energy's RAB over the 2020–25 period compared to its revised proposal.

Our final decision on the prudent and efficient capex to be rolled into the RAB in the 2020–25 period is consistent with our draft decision. This is because Ergon Energy's revised proposal accepted our draft decision on the ex-post review for the actual capex in years 2018–23. In these years, Ergon Energy's actual capex was higher than our forecast, so we reviewed this higher amount to ensure that only prudent and efficient capex is added to the RAB. Our draft decision sets out our ex-post review, where we reduced the amount of capex rolled into the opening RAB by $504.1 million ($ nominal) because we were not satisfied this capex reasonably reflected the capital expenditure criteria.[23]

Figure 8 likewise shows the key drivers of the change in Ergon Energy's forecast RAB over the 2025–30 period compared to its revised proposal. Our final decision projects an increase of $3,549.1 million (22.5%) to the RAB by the end of the 2025–30 period compared to the $4,325.0 million (27.3%) increase in Ergon Energy's revised proposal. We have determined a projected closing RAB of $19,315.4 million ($ nominal) as at 30 June 2030, which is $863.9 million (4.3%) lower than Ergon Energy's revised proposal of $20,179.3 million. This lower value is mainly due to our final decision to reduce Ergon Energy's proposed forecast capex (discussed in Attachment 5). It also reflects our final decisions on the opening RAB as at 1 July 2025, forecast depreciation and expected inflation.

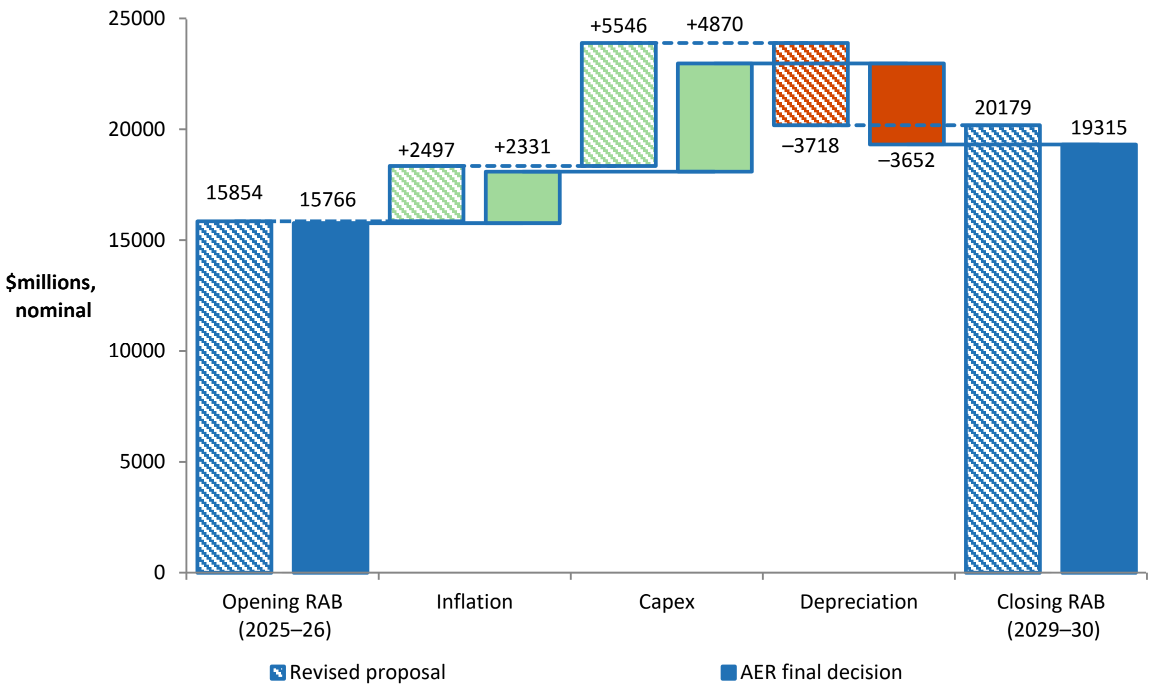
[23] AER, *Draft decision – Attachment 2 – Regulatory asset base – Ergon Energy 2025–30 Distribution revenue proposal*, September 2024, pp. 14–15; AER, *Draft decision – Attachment 5 – Capital expenditure – Ergon Energy 2025–30 Distribution revenue proposal*, September 2024, pp. 21–46.

Figure 7 Key drivers of changes in the RAB over the 2020–25 period – revised proposal compared with AER's final 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 8 Key drivers of changes in the RAB over the 2025–30 period – revised proposal compared with AER's final 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 Post-tax revenue model (PTRM).

2.2 Rate of return and value of imputation credits

The AER's 2022 Rate of Return Instrument (RORI) sets out the approach we will use to estimate the return on debt, the return on equity and the overall rate of return.[24]

The return each business is to receive on its RAB, known as 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 RAB.

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 give a return on equity to investors.

The estimate of the rate of return is important for promoting efficient prices in the long term interests of consumers. If the rate of return is set too low, the network business may not be able to attract sufficient funds to be able to make the required investments in the network and reliability may decline. Conversely, if the rate of return is set too high, the network business may seek to spend too much and consumers will pay inefficiently high tariffs.

We are required by national energy laws and rules to apply the RORI to estimate an allowed rate of return. For this final decision, we have applied the 2022 RORI.[25]

Ergon Energy's revised proposal adopted the 2022 RORI.[26] The 6.09% (nominal vanilla) rate of return in this final decision is higher than the 5.97% placeholder in the revised proposal, principally due to an increase in interest rates.

Our calculated rate of return in Table 1 applies to the first regulatory year of the 2025–30 period. A different rate of return may apply for the remaining years of the period. This is because we will update the return on debt component of the rate of return each year, in accordance with the 2022 RORI, to use a 10-year trailing average portfolio return on debt that is rolled-forward each year. Hence, only 10% of the return on debt is calculated from the most recent averaging period, with 90% from prior periods.

Our final decision accepts Ergon Energy's proposed risk free rate[27] and debt averaging periods[28] because they were consistent with 2022 RORI.[29] For this final decision, we adopt the confidential appendix setting out the averaging periods issued with our draft decision.

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24 AER, *Rate of Return Instrument (Version 1.2)*, March 2024.

25 AER, *Rate of Return Instrument (Version 1.2)*, March 2024.

26 Ergon Energy, *2025-30 Revised Regulatory Proposal*, November 2024, p. 103.

27 AER, *Draft Decision Appendix A - CONFIDENTIAL Appendix to Attachment 3 - Rate of return - Ergon Energy 2025-30 Distribution revenue proposal,* September 2024, p. 1.

28 AER, *Draft Decision Appendix A - CONFIDENTIAL Appendix to Attachment 3 - Rate of return - Ergon Energy 2025-30 Distribution revenue proposal,* September 2024, p. 2.

29 AER, *Rate of return Instrument (version 1.2)*, March 2024, cll 7–8, 23–25.

Table 1 Final decision on Ergon Energy's rate of return (nominal)

	AER's draft decision (2025–30)	Ergon Energy's revised proposal (2025–30)	AER's final decision (2025–30)	Allowed return over the regulatory control period
Nominal risk-free rate	4.35%	3.96%	4.47%[a]	
Market risk premium	6.20%	6.20%	6.20%	
Equity beta	0.6	0.6	0.6	
Return on equity (nominal post-tax)	8.07%	7.68%	8.19%	Constant (%)
Return on debt (nominal pre-tax)	4.68%	4.83%	4.69%[b]	Updated annually
Gearing	60%	60%	60%	Constant (60%)
Nominal vanilla WACC	6.04%	5.97%	6.09%[c]	Updated annually for return on debt
Expected inflation	2.85%	2.85%	2.72%	Constant (%)

Source: AER analysis; AER, *Draft Decision Attachment 3 - Rate of return - Ergon Energy - 2025-30 Distribution revenue proposal*, September 2024, p. 2; Ergon Energy, *2025-30 Revised Regulatory Proposal*, November 2024, pp. 103,105.

(a) Calculated using Ergon Energy's risk-free rate averaging period of 20 business days from 3 February 2025 to 28 February 2025.
(b) Calculated using Ergon Energy's actual nominated return on debt averaging period.
(c) Applied to the first year of the 2025–30 regulatory control period.

Debt and equity raising costs

In addition to compensating for the required rate of return on debt and equity, we provide an allowance for the transaction costs associated with raising debt and equity. We include debt raising costs in the opex forecast because these are regular and ongoing costs which are likely to be incurred each time service providers refinance their debt. On the other hand, we include equity raising costs in the capex forecast because these costs are only incurred once and would be associated with funding the particular capital investments. Our approach to forecasting debt and equity raising costs is set out in more detail in our draft decision.[30] Ergon Energy has proposed to use our approach to estimate debt and equity raising costs.[31]

30 AER, *Draft Decision - Attachment 3 - Rate of return – Ergon energy – 2025-30 Distribution revenue proposal*, September 2024, pp. 4-6.

31 Ergon Energy, *8.03 - Model SCS AER PTRM*, November 2024.

Our final decision is to apply a debt raising cost of 8.37 basis points per annum, which has been used to calculate the debt raising cost forecast set out in section 2.5 in the Overview.

We have updated our estimate for the 2025–30 period based on the benchmark approach using updated inputs. This results in zero equity raising costs.

Imputation credits

Our final decision applies a value of imputation credits (gamma) of 0.57, as set out in the 2022 RORI.[32] Ergon Energy's revised proposal also adopted this value.[33]

Expected inflation

As set out in Table 2, our estimate of expected inflation is 2.72%. It is an estimate of the average annual rate of inflation expected over a five-year period based on the outcome of our 2020 inflation review.[34] Ergon Energy's revised proposal also adopted our approach.[35]

Table 2 Final decision on Ergon Energy's forecast inflation (%)

	Year 1	Year 2	Year 3	Year 4	Year 5	Geometric average
Expected inflation	3.20%	2.70%	2.63%	2.57%	2.50%	2.72%

Source: AER Analysis; RBA, *Statement on Monetary Policy*, February 2025, Table 3.1: Detailed Forecast Table. See https://www.rba.gov.au/publications/smp/2025/feb/outlook.html#table31.

Our final decision uses the Reserve Bank of Australia's (RBA) February 2025 Statement on Monetary Policy (SMP) which contains a consumer price index (CPI) forecast for the year-ending June 2026 and June 2027. This means the first two years of the 2025–30 period are based on RBA forecasts and, thereafter, a linear glide-path from year three to the mid-point of the RBA's inflation target band of 2.5% in year five.

Figure 9 isolates the impact of expected inflation from other parts of our final decision to illustrate its effect 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.

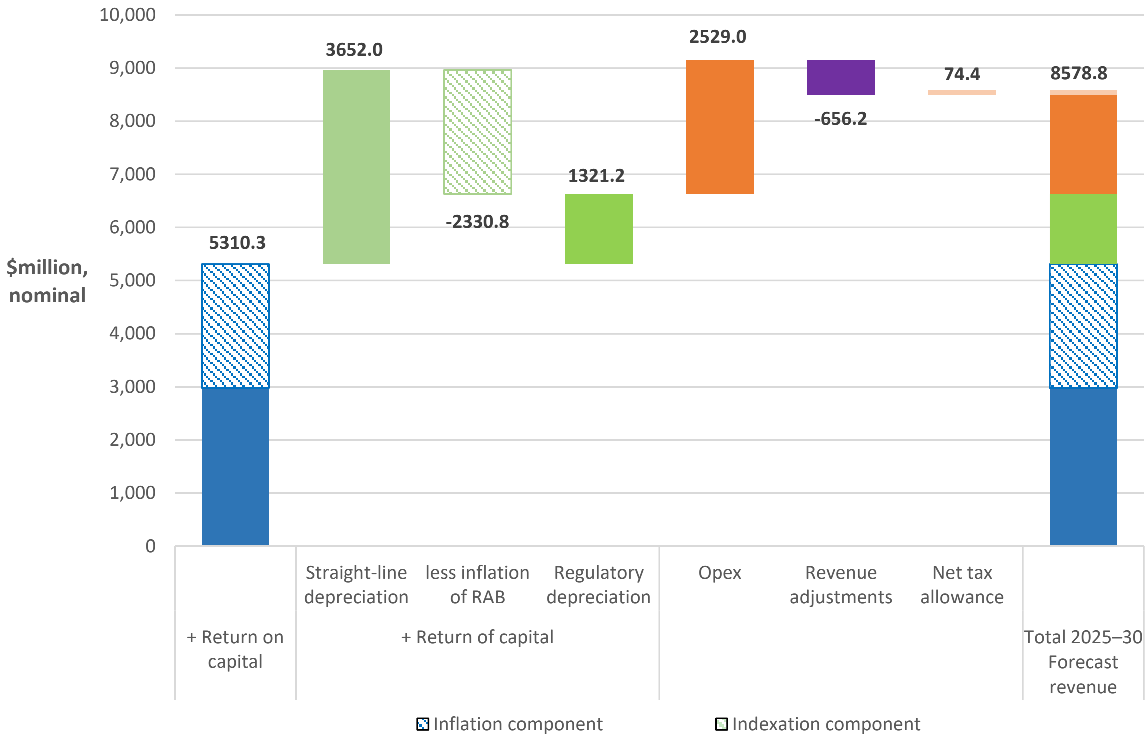
32 AER, *Rate of return Instrument (version 1.2)*, March 2024, cl. 27.

33 Ergon Energy, *2025-30 Revised Regulatory Proposal*, November 2024, p. 106.

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

35 Ergon Energy, *2025-30 Revised Regulatory Proposal*, November 2024, p. 105.

Figure 9 Inflation components in final decision revenue building blocks ($ million, nominal)



Source: AER analysis.

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 final decision determines a regulatory depreciation amount of $1,321.2 million ($ nominal) for the 2025–30 period. This is an increase of $100.2 million (8.2%) from Ergon Energy's revised proposal of $1,221.0 million.

This increase in regulatory depreciation is due to a lower expected inflation rate in our final decision compared to Ergon Energy's revised proposal, which has reduced the indexation of the RAB.[36] This increase is partially offset by our final decisions to reduce forecast capex and the opening RAB as at 1 July 2025 which have reduced straight-line depreciation in the 2025–30 period.

The reasons for our final decision on regulatory depreciation are discussed in Attachment 4.

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36 Since RAB indexation is deducted from straight-line depreciation, the lower RAB indexation results in a higher regulatory depreciation.

2.4 Capital expenditure

Our final decision is to not accept Ergon Energy's forecast total net capex of $5,011.4 million for the 2025–30 period as we are not satisfied that it reasonably reflects the capex criteria. Our alternative forecast is $4,410.7 million which is 12.0% lower than Ergon Energy's forecast. Table 3 sets out our final decision for Ergon Energy by capex category.

Table 3: Final Decision for Ergon Energy, by capex category ($ million, $2024–25)

Category	Ergon Energy's Revised Proposal	AER Final Decision
Replacement	2449.8	1941.3
Network resilience	34.6	34.6
Augex	489.2	432.9
Connections	321.3	321.3
Fleet	222.3	222.3
Property	170.2	170.2
Cyber security	53.3	53.3
ICT	208.4	208.4
CER integration	63.0	63.0
Other non-network	31.6	31.6
Capitalised overheads	1009.7	966.8
Total capex (excluding capital contributions)	**5053.4**	**4445.7**
Less Disposals	-41.9	-41.9
Less Modelling adjustments	n/a	6.9
Net capex	**5011.4**	**4410.7**

Source: Ergon Energy and AER analysis. Numbers may not sum due to rounding.

Note: We recategorised capex from Ergon Energy's revised proposal to align with how we assessed each category. We recategorised $7.9 million of repex, $16.1 million of augex, and $29.4 million of ICT to cyber security. We recategorised $34.6 million of augex to resilience. Consistent with our draft decision, we also recategorised $164.8 million in clearance to ground/structure capex from augex to repex.

Figure 10 depicts Ergon Energy's historical capex trend, its proposed revised forecast for the 2025–30 period, and our final decision.

As can be seen from Figure 10, the AER's ex-post review reduced the value of Ergon Energy's capex overspend in the ex-post period (2018–23) allowed to be rolled into the opening RAB.[37] Ergon Energy has not contested this draft decision position due to affordability concerns.[38] We also observe that the estimates in the last two years of the current period are higher than other years in the current period. This would suggest that another ex-post review is a possibility in the next determination.

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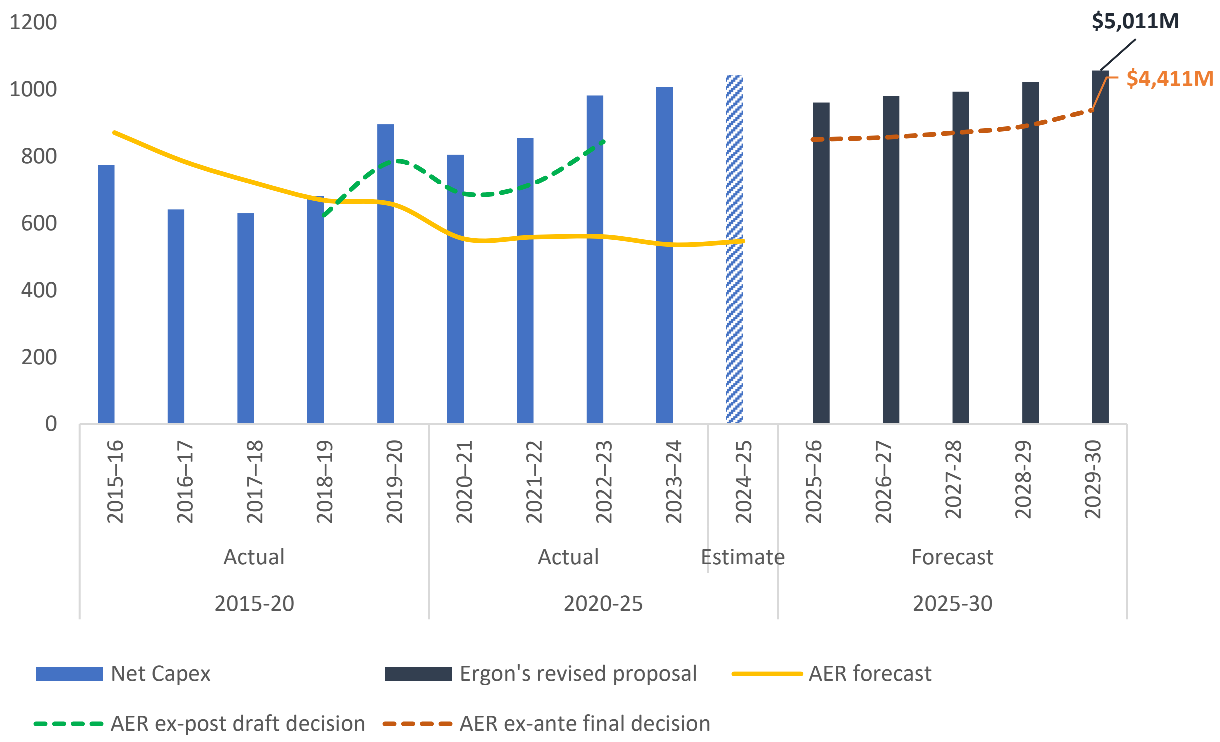
37 An alternative ex-post capex overspend amount of $598 million (a 50% reduction) has been rolled into the opening RAB.

38 Ergon Energy, *Repex 2025-2030: Repex Ex-Post & Ex-Ante Narrative*, 18 November 2024, p.7.

Figure 10 Ergon Energy capex profile ($ million, $2024–25)



Source: Ergon Energy's revised proposal and AER analysis. Numbers may not sum due to rounding.
Note: Capex is net of asset disposals and capital contributions.

We are satisfied that our alternative forecast of total capex of $4,410.7 million is reasonable and sufficient for Ergon Energy to achieve the capex objectives, especially to maintain the safety and reliability of its network. In coming to our decision, we have very carefully considered the safety and reliability risks faced by Ergon Energy, and therefore have accepted Ergon Energy's volume forecasts for a number of programs where safety and reliability risks have been the primary driver. For instance, we have accepted Ergon Energy's clearance volume forecasts and its low density 3kN poles volumes which provides funding for it to address the safety and reliability risks associated with these assets. However, we have not accepted Ergon Energy's forecast where we have not been provided evidence that demonstrates an overall benefit to consumers. For instance, we have not accepted expenditure for inefficient opportunistic replacement.

In making this final decision, we have assessed all information before us including new and additional information Ergon Energy provided in response to our draft decision. As noted in our draft decision, our position on Ergon Energy's forecast capex was a placeholder given the major information gaps in its proposal, especially in repex which is a key driver of its capex forecast for 2025-30. We acknowledge the efforts Ergon Energy has made to address these gaps including extensive engagement with us post release of our draft decision, which included AER staff attending face-to-face meetings over several days to work through the information it had available.

Ergon Energy's new and additional supporting information has allowed us to assess Ergon Energy's proposal afresh, and to undertake deeper analysis to better understand the basis of Ergon Energy's forecast. This has allowed us to accept Ergon Energy's forecast expenditure in full in some cases where we have been satisfied that this information supports a prudent and efficient forecast; namely for Ergon Energy's revised forecast for fleet, network resilience and its augex-related secondary systems program.

In other cases, we were not provided with sufficient evidence to support a prudent and efficient forecast. This was the case for Ergon Energy's repex forecast and aspects of its augex forecast. For repex, our final decision is a higher forecast relative to the draft decision ($97.0 million more than the draft decision). The higher repex forecast in the final decision is reflective of our finding in some cases of Ergon Energy's supporting information justifying more capex (in Ergon Energy's pole and clearance to ground (CTG)/clearance to structure (CTS) programs). But, in other cases, we found the new and additional information reaffirmed our concerns which supported maintaining our draft decision position (for pole top structure, conductor and repex-related secondary system programs). Where we have derived alternative forecasts, these have been based on a bottom-up assessment which addresses Ergon Energy's concerns about the draft decision alternative forecast being based on benchmarking against Essential Energy's network.

There were a number of key findings from our assessment. We encourage Ergon Energy to consider these areas of improvement for future processes. These findings are:

- *Ergon Energy's systemic practice of retrospectively applying new standards to its existing assets*. Ergon Energy is forecasting to continue this practice in its replacement of poles, conductors, and CTG/CTS. The retrospective application of new standards to existing assets is not consistent with good industry practice and results in more assets being replaced than prudent and efficient. The Consumer Challenge Panel's (CCP30) submission also raised concerns about this inefficient practice.
- *Inefficient opportunistic replacement.* We have accepted opportunistic replacement where it is prudent and efficient, such as the replacement of pole top structures and service lines when replacing poles. However, Ergon Energy did not provide sufficient evidence to demonstrate that the practice of replacing these assets when replacing conductors or addressing clearance defects is consistent with prudent and efficient decision-making.
- *Underlying data issues and limited supporting quantitative analysis*. We found some of Ergon Energy's underlying data, such as its historical pole data that its forecast is based on, to be unreliable because of the data inaccuracies and inconsistencies. Also, we found a systemic overstatement of benefits embedded in its cost-benefit analyses.
- *Critical new and additional information was provided by Ergon Energy in its revised proposal, when this is typically provided as part of a NSP's initial proposal.* For instance, Ergon Energy's concerns and details about its low density poles was only revealed in its revised proposal. This does not give stakeholders the opportunity to thoroughly review and provide feedback.
- *Concerns that Ergon Energy's revised proposal did not genuinely reflect its customers' preferences.* We note submissions from EQL's Reset Reference Group (RRG) and the CCP30 which observed that Ergon Energy was biased in the manner that it presented the AER's draft decision. In particular, the CCP30 notes that:

  > …in the Customer Panel Workshops in October, following the draft decision, the Ergon Energy (and Energex) presentations were tilted in the direction of supporting Ergon Energy and Energex's position, with an undercurrent that any reductions in funding by the AER would

> most likely result in reduced service quality to customers and heightened safety risks. As a result of this one-sided view, the feedback from the Customer Panel and Focus Group workshops heavily favoured the Ergon position.

We outline below our key findings at the program level of Ergon Energy's repex forecast which is the main driver of Ergon Energy's capex forecast. We also discuss our position on Ergon Energy's augex forecast.

Poles – a reduction of 31.5% relative to Ergon Energy's forecast of $744.4 million

After reviewing all the information before us, we consider that Ergon Energy's forecast poles repex, which is based on a historical 3-year average volume of replacement from 2020–21 to 2022–23, is overstated and not prudent and efficient. We acknowledge that new information provided by Ergon Energy especially about its programs that are safety and reliability driven indicates that there are valid reasons for a move from our draft decision position. We also acknowledge that new information provided by Ergon Energy demonstrates that it has different pole management and standards to Energex.

However, we also found that Ergon Energy's forecast is driven by the inefficient practice of retrospectively applying a new standard (AS 7000:2010) to its existing pole population. As Ergon Energy's historical volumes includes replacement volumes based on this inefficient practice, we consider it is not a reasonable basis to derive forecast volumes. The retrospective application of a new standard to existing assets is not consistent with good industry practice and results in assets being replaced regardless of condition. Of further concern is that this practice is systemic across other assets.

We acknowledge the concerns raised by Ergon Energy about its low density 3kN poles in the western region. Namely that the low density 3kN poles were one of the main reasons for its overspend in the ex-post period (2018–23) and a key driver for the elevated pole replacement levels in the forecast period. We note that while these poles represent only about 10% of its pole population, it makes up about 25% of pole failures where possibility of staking of this type of pole is lower compared to other pole types. Our alternative pole replacement volume forecast includes this pole type.

Our alternative pole replacement volume forecast is 10,000 pole interventions per annum, compared to Ergon Energy's 16,600 per annum. Our alternative volume forecast was derived using Ergon Energy's own condition-based forecasting model – the Condition Based Risk Management (CBRM) model – which Ergon Energy uses to forecast proactive replacements and support inspection driven defect forecasts. We found this model, which is a common asset management tool, to be a reasonable basis to derive a robust pole volume replacement forecast.

Conductors – a reduction of 18.0% relative to Ergon Energy's forecast of $494.8 million

Our final decision maintains our draft decision position of accepting Ergon Energy's conductor volumes but not all its opportunistic replacement of poles, pole-top structures and service lines.[39]

We found Ergon Energy's opportunistic replacement is due to its inefficient practice of retrospectively applying new standards to existing assets, a practice that is not consistent with good industry practice.

Pole-top structures – a reduction of 45.3% relative to Ergon Energy's forecast of $252.6 million

Our final decision maintains our draft decision position. Our alternative forecast is based on Ergon Energy's historical replacement volumes over the current period as Ergon Energy did not provide sufficient justification for the material step up in forecast expenditure relative to the ex-post (2018–23) and current (2020–2025) period. We found its supporting business case did not provide sufficient quantitative evidence to support the proactive replacement of pole top structure assets where there are minor defects. Its cost benefit analysis materially overstates the benefits of the program. Our review of its defect data also indicates that Ergon Energy is overstating the risk associated with these minor defects.

CTG/CTS – a reduction of 30.1% relative to Ergon Energy's forecast of $164.8 million

Our final decision maintains our draft decision of accepting Ergon Energy's clearance volumes for both CTG and CTS. We have applied a higher CTG unit rate given further information provided by Ergon Energy, however we were not provided with sufficient evidence to support the reasonableness of Ergon Energy's higher CTS unit rate.

Repex-related secondary systems – a reduction of 18.6% relative to Ergon Energy's forecast of $111.3 million.

Our final decision maintains our draft decision which was based on a bottom-up build and EMCa's advice. We found that Ergon Energy's NPV model materially overstates the benefits which in turn materially overstates the repex to achieve these benefits. This appears to be systemic issue across Ergon Energy's cost benefit models we reviewed.

Augex – a reduction of 11.5% relative to Ergon Energy's forecast of $489.2 million

Our final decision accepts Ergon Energy's revised forecast for its augex-related secondary systems program as Ergon Energy provided sufficient evidence to support the prudency and efficiency of its forecast.

However, we have maintained our draft decision position to not include capex for its reliability program and back up reach protection program in our total capex forecast. For its reliability

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39 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 ageing crossarm or conductor during a pole replacement.

program, we found its cost benefit analysis overstates the benefits as it does not have regard to additional capex already approved for similar assets. We also found a lack of quantitative evidence to support the need for its back up reach protection program.

2.5 Operating expenditure

Our final decision is to not accept Ergon Energy's total opex forecast of $2,562.9 million ($2024–25),[40] including debt raising costs, for the 2025–30 period. This is primarily driven by us not accepting Ergon Energy's use of 2023–24 as the base year to forecast its revised opex proposal, and our substitution of Ergon Energy's actual 2022–23 opex as the base year for our alternative estimate of total opex. We consider that Ergon Energy's actual 2022–23 opex best represents the nature of prudent and efficient costs it will require in the 2025–30 regulatory period. Our reasoning behind our decision is outlined in further detail in Attachment 6.

As we relied on Ergon Energy's 2022–23 actual opex for our opex forecast, we have not applied an efficiency adjustment to base opex or included transition costs, as proposed by Ergon Energy for its 2023-24 base year. We also did not apply Ergon's proposed base adjustment for its 2023–24 storms, because these were not incurred in 2022–23. We have applied the other base adjustments and trend consistent with Ergon Energy's revised proposal and our draft decision, with the amounts updated using Ergon Energy's actual expenditure for 2022–23. The differences between Ergon Energy's revised proposal and our alternative estimates for these opex components are largely due to the mechanical update from moving to a 2022–23 base year.

Key differences between Ergon Energy's revised proposal and our alternative estimate of total opex that are not primarily driven by the change of base year include:

- **Ratcheted maximum demand**: we substituted Ergon Energy's revised maximum demand forecast with our alternative forecast and applied our standard approach to ratchetting. This reduced the output growth forecast in our alternative estimate by $23.0 million relative to Ergon Energy's revised proposal.
- **Smart meter data step change**: we did not include the $10.0 million Ergon proposed for the smart meter data step as while we agreed that it was prudent for Ergon to upgrade its analytics and data management capabilities as proposed, we consider that this could be funded through reported expenditure already in its 2022-23 opex.

Accounting for the above changes, our alternative estimate of total forecast opex is $2,331.1 million. This is materially below ($231.8 million or 9.0%) Ergon Energy's revised proposal total opex forecast of $2,562.9 million.[41] Our final decision is therefore to determine a substitute total opex forecast of $2,331.1 million, including our estimate of debt raising costs, for the 2025–30 period, as reasonably reflecting the opex criteria.[42]

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40 All dollars referenced in this attachment are on a $2024–25 basis.

41 Ergon Energy, *6.01 – Model – SCS Opex model*, November 2024.

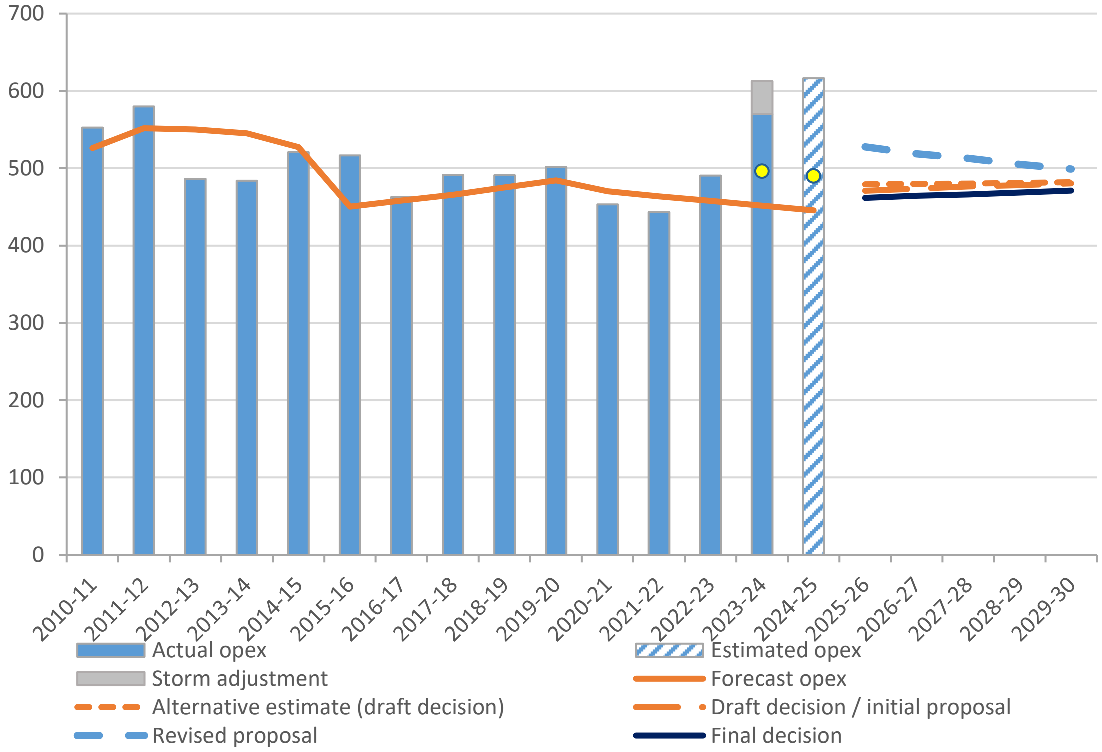
42 The opex criteria are set out in cl. 6.5.6(c) of the NER and the opex factors are set out in cl. 6.5.6(e). We must not accept a distributor's proposed opex if we are not satisfied that it reasonably reflects those criteria: NER, cl. 6.5.5(d).

Our final decision opex forecast for Ergon Energy is:

- $42.9 million or 1.9% higher than the opex forecast we approved in our final decision for the 2020–25 regulatory control period[43]
- $285.2 million or 10.9% lower than Ergon Energy's actual (and estimated) opex in the 2020–25 regulatory period
- $48.0 million or 2.0% lower than Ergon Energy's initial proposal, which we accepted in our draft decision.

Figure 11 compares the opex forecast we approve in this final decision for the 2025–30 period to Ergon Energy's revised proposal, Ergon Energy's initial proposal, which was also our draft decision, and our alternative estimate for the draft decision for the 2025–30 period. It also shows the forecasts we approved for the last two regulatory periods from 2009–10 to 2024–25, and Ergon Energy's actual and estimated opex across that period.

Figure 11: Historical and forecast opex ($million, 2024–25)



Source: Ergon, Economic benchmarking – regulatory information notice responses 2010–24; AER, Final decision PTRM 2010–15, May 2010; AER, Final decision PTRM 2015–20, October 2015; AER, Final decision PTRM 2020–25, June 2020; Energex, 2025–30 Regulatory proposal, November 2024; AER analysis

43 Difference is calculated based on the opex allowance for the five-year 2020–25 period converted to real 2024–25 dollars using unlagged inflation.

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 final decision determines an estimated cost of corporate income tax amount of $74.4 million ($ nominal) for Ergon Energy over the 2025–30 period. This is an increase of $27.2 million (57.6%) from Ergon Energy's proposal of $47.2 million. This increase is primarily due to our final decision on a higher regulatory depreciation amount as discussed in section 2.3,[44] and a higher return on equity amount as discussed in section 2.2.[45]

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 final decision includes:

- EBSS - a revenue adjustment (penalty) of $39.5 million ($2024–25) from the application of the EBSS in the 2020–25 period. This is $39.5 million less than Ergon's revised proposal, which was to not apply its calculated EBSS penalties of $575.7 million calculated using 2023–24 as the base year. The difference is because we:
  - used 2022–23 as the base year to calculate our EBSS carryover amount
  - included forecasts for Ergon Energy's 2023–24 storm cost pass through approved in our April 2025 determination
  - updated forecast inflation using the most recent figures
  - applied the EBSS penalties Ergon Energy has accrued in the 2020–25 period.
- CESS - a revenue adjustment (penalty) of $579.5 million ($2024–25) under the CESS. This is higher than Ergon Energy's revised proposal penalty of $576.6 million ($2024–25) because we have used the most recent inflation data and adjusted the CESS to account for adjusted forecast capex in recent cost pass through decisions.
- DMIAM – an allowance of $7.2 million ($2024–25) for the Demand Management Innovation Allowance Mechanism (DMIAM), which 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 PTRM. Ergon Energy will submit demand management projects for approval under the DMIAM. Any part of the $7.2 million that is not spent on an approved project will be returned to consumers in the subsequent period.

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44 The higher regulatory depreciation is driven by a lower expected inflation rate applied in our final decision compared to Ergon Energy's revised proposal. All else being equal, a higher regulatory depreciation increases the cost of corporate income tax as it is a component of revenue for tax purposes.

45 The higher return on equity amount is driven by a higher rate of return on equity determined in our final decision compared to Ergon Energy's revised proposal. All else being equal, a higher return on equity amount increases the cost of corporate income tax as it is a component of revenue for tax purposes.

The combined effect of these revenue adjustments is a negative $611.7 million ($2024–25) revenue adjustment building block in this final decision compared to the negative $568.9 million in Ergon Energy's revised proposal.

3 Incentive schemes

3.1 Capital Expenditure Sharing Scheme

Our final decision is to apply a CESS revenue adjustment (decrement) of -$579.5 million for the CESS. This is from the application of the CESS in the 2020–25 period and the corresponding CESS carryover true-up for 2019–20. Our final decision on the revenue impact of the application of the CESS in the 2020–25 period and the corresponding CESS carryover true-up 2019–20 is summarised in Table 4.

Table 4 CESS revenue increments in 2025–30 ($ million, 2025–30)

Revenue Adjustments	2025–26	2026–27	2027–28	2028–29	2029–30	Total
CESS revenue increments as per NER 6.4.3(a)(5)	-111.1	-111.1	-111.1	-111.1	-111.1	-555.4
CESS carryover true-up 2019–20	-4.8	-4.8	-4.8	-4.8	-4.8	-24.0
AER final decision CESS	-115.9	-115.9	-115.9	-115.9	-115.9	-579.5

Note: Numbers may not sum due to rounding.
Source: AER analysis; Ergon Energy, *7.01 – SCS CESS Model*, November 2024.

Ergon Energy's revised proposal adjusted for its actual/estimate capex for the current regulatory period and amended its allowance to reflect past cost pass throughs, resulting in an increase in its CESS decrement of -$86.9 million.[46] This adjustment has reduced the overspend from our draft decision and resulted in a CESS total decrement of -$579.5 million. The reasoning for our final decision is consistent with our draft decision.

In its revised proposal, Ergon Energy also accepted our ex-post capex review draft decision.[47]

3.2 Efficiency Benefit Sharing Scheme

Our final decision is to include EBSS carryover amounts (penalties) totalling -$39.5 million ($2024–25),[48] from the application of the EBSS in the 2020–25 period.[49] Our final decision is $39.5 million less than Ergon Energy's revised proposal, which was to not apply its calculated EBSS penalties of -$575.7 million calculated using 2023–24 as the base year. As set out in section 2.7, the difference is because we:

- used 2022–23 as the base year to calculate the EBSS carryover amounts, which contrasts to Ergon Energy's revised proposal, which used 2023–24 as the base year for

46 Ergon Energy, *7.01 – SCS CESS Model*, November 2024.

47 Ergon Energy, *2025–30 Revised Regulatory Proposal,* November 2024, p. 95.

48 All dollars referenced in this attachment are on a $2024–25 basis.

49 NER, cl. 6.4.3(a)(5).

both its total opex forecast and EBSS penalties calculations. Our reasons for choosing 2022–23 as the base year are outlined in Attachment 6.

- included forecasts for Ergon Energy's 2023–24 storm cost pass through approved in our April 2025 determination
- updated forecast inflation
- applied the EBSS penalties Ergon Energy has accrued in the 2020–25 period. This contrasts to Ergon Energy's revised proposal, which proposed that we not apply the EBSS penalties it had accrued in the 2020–25 period.

The full detail on our final decision for the EBSS is set out in in Attachment 8.

We set out our final decision on the EBSS carryover amounts Ergon Energy accrued during the 2020–25 period in Table 5, along with Ergon Energy's proposal, and the difference.

Table 5 Final decision on carryover amounts ($million, 2024–25)

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
Ergon Energy's proposal	–	–	–	–	–	**–**
AER final decision	–28.9	–40.3	–45.2	–	75.0	**–39.5**
Difference	–28.9	–40.3	–45.2	–	75.0	**–39.5**

Source: Ergon Energy, *7.03 – EBSS Model*, November 2024; AER analysis.
Note: Numbers may not add up due to rounding. '–' represents zero.

We will continue to apply version 2 of the EBSS to Ergon Energy in the 2025–30 period.[50] This contrasts with Ergon Energy's revised proposal, which was to not apply the EBSS in the 2025–30 period. Where actual base year opex is used to forecast required opex in the following period, as we have done in our opex final decision (Attachment 6), we consider the EBSS should be applied. This provides a continuous incentive to pursue efficiency improvements in opex and provide for a fair sharing of these between Ergon Energy and network users. Consumers benefit from improved efficiencies through lower opex in regulated revenues for future periods. In calculating EBSS carryover amounts, we will exclude cost categories and make adjustments, as required by the scheme and set out in Attachment 8 of our final decision.

3.3 Service Target Performance Incentive Scheme

Ergon Energy accepted our draft decision to apply STPIS version 2.0 for the 2025–30 regulatory control period, including the continued application of the customer service parameter (telephone answering) in the absence of a Customer Service Incentive Scheme.[51]

Our final decision is consistent with Attachment 10 of our draft decision, albeit with changes to performance targets, incentive rates and value of customer reliability (VCR) as a result of

50 AER, *Efficiency benefit sharing scheme for electricity network service providers*, November 2013.

51 Ergon, *2025-30 Revised Regulatory Proposal*, 2 December 2024 – public, pp. 15, 97-98.

updates to the final revenue numbers, the CPI and the publication of 2024 VCR values.[52] The reasoning behind our final decision position is outlined in the draft decision.[53]

Ergon Energy is also committed to publishing a new Customer Service Performance Measures Scorecard independently of the regulatory determination process. The scorecard will be introduced by Ergon Energy at the commencement of the 2025–30 regulatory control period and provide a performance report on the services that its Voice of the Customer Panel participants indicated were important to them.[54]

On this, we note CCP30's advice that 'while this work was encouraging', to its knowledge 'EQL has not yet presented any detail on this initiative'. The AER expects that Ergon Energy will continue to work on this initiative after the regulatory reset is complete.[55]

Our final decision on the applicable performance targets and incentive rates that will apply to Ergon Energy for the 2025–30 period is contained in Table 6, Table 7 and Table 8. The VCR for network segments outlined in Table 8 were applied to calculate Ergon Energy's incentive rates for the 2025–30 period. The parameters that will apply to each component of the STPIS are published as part of this final decision.

Table 6 Final decision – STPIS performance targets for Ergon Energy for the 2025–30 period

	Urban	Short Rural	Long rural	Telephone answering
SAIDI (minutes)[56]	122.0950	280.0254	789.3980	N/A
SAIFI (interruptions)[57]	1.2169	2.3538	4.5277	N/A
Customer service (%)	N/A	N/A	N/A	85.76

Source: AER analysis.

Table 7 Final decision – STPIS incentive rates for Ergon Energy for the 2025–30 period

	Urban	Short Rural	Long rural	Telephone answering
ir - SAIDI	0.0099	0.0129	0.0026	N/A
ir - SAIFI	0.6606	1.0218	0.3023	N/A

52 On 18 December 2024, we published the 2024 VCR in our final report on the 2024 VCR values.

53 AER - Draft Decision Attachment 10 - Service target performance incentive scheme – Ergon Energy - 2025-30 Distribution revenue proposal - September 2024

54 Ergon Energy Network Revised Regulatory Proposal 2025-30, November 2024, pp.31 and 32

55 CCP 30 Advice to the AER regarding the Draft Decision and Revised Regulatory Proposal 2025-30 Ergon Energy Network, January 2025, p.12.

56 System Average Interruption Duration Index (SAIDI).

57 System Average Interruption Frequency Index (SAIFI).

Customer service (%)	N/A	N/A	N/A	-0.0400

Source: AER analysis.
Note: ir is the incentive rate (expressed in a percentage per unit of the parameter).

Table 8 Value of customer reliability (VCR) ($/MWh)

	CBD	Urban	Short rural
VCR	25,806	25,806	25,806

Source: AER, Value of customer reliability review, final report, December 2024, pp. 62 (Table 20 NEM-wide and regional VCR). Escalated to the December 2024 quarter.

3.4 Demand Management Incentive Scheme (DMIS) and Demand Management Innovation Allowance Mechanism (DMIAM)

Our final decision is to apply the DMIS and DMIAM to Ergon Energy in the 2025–30 regulatory control period. This approach is consistent with Ergon Energy's revised proposal[58] and our draft decision on DMIS and DMIAM.[59] The reasoning behind our position is also explained in the draft decision. The DMIAM allowance for the 2025–30 period, based on the final PTRM, is contained in Table 9.

Table 9 Demand management innovation allowance ($million, 2024–25)

	2025-26	2026-27	2027-28	2028-29	2029-30	Total
Ergon Energy – DMIAM	1.35	1.38	1.41	1.48	1.56	7.18

Source: AER analysis

58 Ergon, *2025-30 Revised Regulatory Proposal*, 2 December 2024 – public, p. 99.

59 AER, *Draft Decision Attachment 11 - DMIS and DMIAM – Ergon Energy - 2025-30 Distribution revenue proposal*, September 2024.

4 Tariff structure statement

Ergon Energy's revised 2025–30 regulatory proposal includes its third tariff structure statement, accompanied by an indicative pricing schedule. The 2025–30 tariff structure statement will apply from 1 July 2025 and remain in effect until the end of the regulatory period. These network tariffs are charged to retailers who package them with other costs, such as the cost of wholesale energy, in their service offerings to electricity customers.

Our final decision is to amend Ergon Energy's revised proposed tariff structure statement to the extent necessary to make it compliant with the NER[60] to:

- include the proposed primary dynamic price storage tariffs and edit the contingent tariff adjustment associated with introducing these tariffs during the 2025–30 period
- reject the proposed contingent tariff adjustment to introduce the proposed *secondary* dynamic price storage tariffs in the 2025–30 period (these would remain as a tariff trial)
- include supply times for primary and secondary load control tariffs
- edit section 1.1. to restore text from the initial tariff structure statement submitted in January 2024 to make it consistent with the NER framework under which AER approval applies to the entirety of a tariff structure statement
- edit the proposed contingent tariff adjustment to shift the peak and off-peak windows during the 2025–30 period so that changes are clear and the trigger well defined
- edit section 3.6 of the revised tariff structure statement to reflect that some customers with basic meters will remain on withdrawn tariffs until they can be reassigned to the appropriate tariff at the first meter read
- reject proposed changes in the revised tariff structure statement to set $zero anytime charges and introduce small fixed charges in secondary controlled load tariffs, and edit back in Ergon Energy's initially proposed secondary load control tariffs (with no fixed charges and anytime volume charges).

Under NER cl. 6.12.3(k), the AER must approve a tariff structure statement unless the AER is reasonably satisfied that the proposed tariff structure statement does not comply with the pricing principles for direct control services or other applicable requirements of the NER.

The minimum changes we have made are in accordance with NER cl. 6.12.3(l). Under NER cl. 6.12.13(l), if the AER refuses to approve a proposed tariff structure statement, the AER must include in that distribution determination an amended tariff structure statement which is:

- determined on the basis of the distributor's proposed tariff structure statement; and
- amended from that basis only to the extent necessary to enable it to be approved in accordance with the NER.

60 NER, cl. 6.12.3(l)(2).

We are satisfied that, with the above amendments, Ergon Energy's tariff structure statement complies with the requirements of the NER, the NEL and contributes to achieving the NEO.[61]

These amendments complement the changes Ergon Energy made in its revised tariff structure statement in response to our draft decision. The changes included:

- withdrawing two-way pricing
- making time-of-use tariffs the default tariffs for new and existing small customers
- modifying proposed storage tariffs
- proposing a time-of-use tariff for large customers consuming up to 160 MWh per annum and demand over 120 kVA, and including a contingent tariff adjustment that if the Queensland Government changes the large customer threshold (e.g. from 100 MWh per annum to 160 MWh per annum), the new threshold would also apply in Ergon Energy's tariff structure statement
- providing more information on the Queensland Electricity Connections Manual and eligibility of flexible load control tariffs, and proposing a contingent tariff adjustment to introduce flexible load control tariffs from 2028 or earlier (contingent on billing system capabilities)
- withdrawing a proposed contingent tariff adjustment to withdraw obsolete tariffs during the 2025–30 period and instead withdrawing a wide inclining block tariff with no customers on it from 1 July 2025
- withdrawing a proposed contingent tariff adjustment to bring forward the introduction of optional demand-only tariffs
- providing more information on areas where the AER encouraged change in our draft decision, such as bill impact analysis and information on withdrawn tariffs.

Ergon Energy proposed the following additional changes in its revised tariff structure statement (ones not in response to our draft decision):

- shifting the duration that customers remain on a basic meter tariff from 12 months following the end of the financial year on which the upgrade occurred, to 12 months from the time their meters are replaced
- introducing a contingent tariff adjustment to adapt time-of-use charging windows for residential customer tariffs to maintain peak and off-peak alignment during the 2025–30 period
- editing section 1.1 of their tariff structure statements to indicate that elements of the approved tariff structure statement would apply for the 2025–30 period, rather than the entire tariff structure statement
- simplifying the small business time-of-use tariff by aligning structures / charging windows with the default residential time-of-use tariff

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[61] NER, cl. 6.12.3(k) and NEL, s 7.

- setting anytime volume changes to $zero in secondary controlled load tariffs and introducing low fixed charges (its initial proposal included $zero fixed charges and positive volume charges)
- aligning Ergon Energy's small customer volume and demand charges to those in Energex's network (i.e. tariffs for customers in both networks have the same volume and demand charges)
- aligning volume and demand charges for large customer tariffs across Ergon Energy's pricing zones (East, West and Mt Isa)
- assigning ~500 large business LV customers with accumulation meters currently on the Demand Small tariff, to the large business flat tariff. Customers could opt back into the Demand Small tariff on receipt of a smart meter.

We make our decision by assessing whether the proposed tariff structure statement complies with the pricing principles and other applicable rules within the NER, and we make this decision in a manner that contributes to the achievement of the NEO. This includes that network tariffs progress towards cost reflectivity, to signal to retailers (and through retailers to customers) periods of network capacity and congestion. Managing the network demand and supply imbalances to increase capacity utilisation could mitigate future costs by reducing the need for network augmentation, lowering future network bills for all consumers.

In making our final decision, we have considered that tariffs may vary from complying purely with the economic pricing principles to the extent permitted to consider customer impacts, retailer ability to incorporate tariffs in a retail offer and/or customer understandability, and that tariffs comply with the NER and other applicable regulatory instruments.[62]

We have considered the structure of default tariffs as an important mechanism in the 2025–30 resets to manage customer impacts. We commend Ergon Energy for its continued proposal of network tariffs that progress towards cost reflectivity. However, we are aware of customers being assigned to demand network tariffs and consequentially to demand retail offers that they did not want or understand, and of retailers not actively reassigning those customers to their preferred tariff structure. For example, ECA's December 2024 Consumer Energy Report Card found that 69% of customers surveyed either did not know what retail tariff they were on or were put on a cost-reflective *retail* tariff by their retailer, not by choice.[63] We are also aware that customers are more likely to be on demand *retail* tariffs in networks where demand tariffs were or are the default network tariff.[64] In this context, we have considered the relative impacts from different tariff structures and determined the default network tariff should be one more easily understood by customers and which therefore affords them greater opportunity to mitigate impacts through decisions about usage. This is the current context in which the AER has made the decision (discussed in section 19.4.2.1 of Attachment 19) that even though Ergon Energy's time-of-use demand tariffs for small

62 NER, cl. 6.18.5(c).

63 ECA, *Consumer knowledge of electricity pricing and responsiveness to price signals, Consumer Energy Report Card,* January 2025, p 6.

64 ACCC*, Inquiry into the National Electricity Market: December 2024 Report,* p 29. We note that demand tariffs are no longer the default for small customers in Endeavour Energy's network.

customers were cost reflective and could be approved, their time-of-use tariff options are more appropriate *default* tariffs on consideration of customer impacts.

Further, a 2023 addition to the NEO is contribution to the achievement of emissions reduction targets. Consideration of this element of the NEO was behind the AER decision (discussed in section 19.4.5.1 of Attachment 19) that although Ergon Energy's large business tariffs are cost reflective, large low voltage (LV) customers with peaky load should have access to a cost reflective time-of-use tariff at this point in time.

In Attachment 19 we describe our assessment of Ergon Energy and Energex's proposed revised tariff structure statements together. In making our final decision, we also considered the 4 late amendments Ergon Energy made to its tariff structure statement – one on 20 December 2024 and 3 on 6 February 2025. Attachment 19 of our final decision is to be read alongside attachment 19 of our *draft* decision, in which we approved many elements of Ergon Energy's initial proposed tariff structure statement, including its procedures for assigning retail customers to tariff classes.

Alongside Attachment 19, we publish marked up and clean versions of Ergon Energy's tariff structure statement and its revised indicative price schedule.

5 Other price terms and conditions

In this section, we consider other aspects of our determination, which include application of the AEMC metering review and Ergon Energy's negotiated services and connection policy.

5.1 Metering services

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 determination process, 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.[65] Our draft decision considered this constituted a material change in circumstances, which justified departing from the classification of legacy metering services in the Framework and approach (F&A).[66] Subsequent to our draft decision, the AEMC made the *Accelerating smart meter deployment* rule change determination in November 2024. This rule change incorporated the outcomes of the AEMC's review into the National Electricity Rules, revising the timeframe of the completion of the rollout to November 2030.[67]

Consistent with this, our final decision accepts Ergon Energy's proposal to reclassify legacy metering as standard control services and the application of a revenue cap. The reasons for our reclassification decision are outlined in attachment 13. This is consistent with our guidance note and provides an outcome that is in the long-term interests of consumers.[68] 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.

In addition, our final decision accepts Ergon Energy's revised proposal for no new capex, including for the mount Isa-Cloncurry Network, its proposal to apply accelerated depreciation to the regulated asset base, and its proposed cost recovery approach (a flat per customer charge to low voltage customers). Our final decision substitutes a slightly lower amount for regulatory depreciation and a slightly higher amount for the return on capital reflecting updated inputs based on the 2022 rate of return instrument. We also substitute our alternate estimate for forecast metering opex, applying a bottom-up approach, with mechanical updates for forecast inflation. As a result, our final decision is to not accept Ergon Energy's proposed total annual revenue requirement of $170.7 million ($nominal, smoothed) but

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

66 AER - Draft Decision Attachment 13 – Classification of service – Ergon Energy – 2025-30 Distribution revenue proposal, September 2024.

67 AEMC, *Final rule determination, Accelerating smart meter deployment*, 28 November 2024, p. 1.

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

substitute it with our total annual revenue requirement of $170.71 million ($nominal, smoothed) reflecting these inputs. The reasons for our decision are discussed in detail at attachment 20.

5.2 Negotiating framework and criteria

In our draft decision, we approved Ergon Energy's proposed distribution negotiating framework for the 2025–30 period.[69] We did not receive any objections or submissions on our draft decision. Our final decision maintains the decision to approve Ergon Energy's negotiating framework.

We are also required to decide on the Negotiated distribution service criteria for the distributor. Our final decision is to retain the Negotiated distribution service criteria published for Ergon Energy in February 2024 for the 2025–30 period.[70] Details of Negotiated distribution service criteria are set out in attachment 17 of our draft decision.[71]

5.3 Connection policy

While our draft decision accepted Ergon Energy's connection policy, Ergon Energy submitted an updated connection policy with its revised regulatory proposal.

In 2024 the AER's Connection charge guidelines were updated to reflect new terminology per the AEMC's Integrating Energy Storage Systems (IESS) rule change.

Ergon Energy's revised connection policy reflects the IESS rule change and the updated Connection charge guidelines.

We note the increase in the shared network augmentation rates calculated using the standard methodology (based on long run marginal costs) and the application of the Incremental Cost Shared Network (ICSN). While this is confined to a small subset of customer connections we expect Ergon Energy to effectively communicate the impactful changes to its customers.

We also reviewed the upfront payment threshold to ensure it complies with the Connection charge guidelines. It has been updated to $6,942 ($2024–25), which will be escalated annually with CPI to ensure that it has been calculated in accordance with the Connection charge guidelines. Using the same methodology, Ergon Energy has also updated its pioneer scheme payment threshold.

The updated Ergon Energy connection policy meets the requirement in Part DA of Chapter 6 of the NER and our final decision is to approve this policy.

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69 AER, *Draft Decision Attachment 17 - Negotiated services framework and criteria - Ergon Energy - 2025-30 Distribution revenue proposal*, September 2024.

70 AER, *Proposed negotiation distribution service criteria - Ergon Energy and Energex - 2025-30*, February 2024.

71 AER, *Draft Decision Attachment 17 - Negotiated services framework and criteria - Ergon Energy - 2025-30 Distribution revenue proposal*, September 2024, pp. 5-7.

6 Constituent decisions

Our final 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 final 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 final decision is to not approve the annual revenue requirement set out in Ergon Energy’s building block proposal. Our final 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. Our final 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 final 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 final 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 final decision is to not accept Ergon Energy’s proposed total forecast net capital expenditure. For main standard control services, we do not accept Ergon Energy’s proposed net capital expenditure of $5,011.4 million ($2024–25). Our final decision includes an alternative estimate of $4,410.7 million ($2024–25). The reasons for our final decision are set out in Attachment 5. For metering, we accept Ergon Energy’s proposed 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 final decision is to not accept Ergon Energy’s proposed total forecast operating expenditure. For main standard control services, we do not accept Ergon Energy’s proposed total forecast operating expenditure, inclusive of debt raising costs and exclusive of DMIAM of

<table>
<tr><th>Constituent component</th></tr>
<tr><td>$2,562.9 million ($2024–25). Our final decision includes an alternative estimate of Ergon Energy’s total forecast operating expenditure, inclusive of debt raising costs and exclusive of DMIAM of $2,331.1 million ($2024–25). The reasons for our final decision are set out in Section 2.5 of this Overview and in Attachment 6.

For metering, we do not accept Ergon Energy’s proposed total forecast operating expenditure forecast of $110.5 million ($2024–25) and replace it with a forecast of $111.0 million ($2024–25). This is set out in Attachment 20.</td></tr>
<tr><td>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.</td></tr>
<tr><td>In accordance with clause 6.12.1(5) of the NER and the 2022 Rate of Return Instrument, the AER's final decision is that the allowed rate of return for the 2025–26 regulatory year is 6.09% (nominal vanilla) for the reasons set out in Section 2.2 of this Overview. 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.</td></tr>
<tr><td>In accordance with clause 6.12.1(5A) of the NER and the 2022 Rate of Return Instrument, the AER's final decision on the value of imputation credits as referred to in clause 6.5.3 is to adopt a value of 0.57. Our final decision is set out in Section 2.2 of this Overview.</td></tr>
<tr><td>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 final decision on Ergon Energy’s main standard control services regulatory asset base as at 1 July 2025 is $15,766.3 million ($ nominal). The reasons for our final decision are set out in Attachment 2.

The AER’s final decision on Ergon Energy’s metering regulatory asset base as at 1 July 2025 is $41.7 million ($ nominal). This is discussed in Attachment 20.</td></tr>
<tr><td>In accordance with clause 6.12.1(7) of the NER, the AER's final decision on Ergon Energy’s estimated cost of corporate income tax for main standard control services is $74.4 million ($ nominal) for the 2025–30 regulatory control period. The reasons for our final 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.
<table>
<tr><th>($ million, nominal)</th><th>2025–26</th><th>2026–27</th><th>2027–28</th><th>2028–29</th><th>2029–30</th><th>Total</th></tr>
<tr><td>Tax payable</td><td>15.5</td><td>30.0</td><td>36.0</td><td>42.9</td><td>48.7</td><td>173.1</td></tr>
<tr><td>Less: value of imputation credits</td><td>8.8</td><td>17.1</td><td>20.5</td><td>24.4</td><td>27.7</td><td>98.7</td></tr>
<tr><td>Net cost of corporate income tax</td><td>6.7</td><td>12.9</td><td>15.5</td><td>18.4</td><td>20.9</td><td>74.4</td></tr>
</table>
The AER’s final decision on Ergon Energy’s cost of corporate income tax for metering is $0.0 million ($ nominal) for the 2025–30 regulatory control period.</td></tr>
</table>

Constituent component
In accordance with clause 6.12.1(8) of the NER, the AER's final decision is to not approve the depreciation schedules submitted by Ergon Energy. For main standard control services, our final decision substitutes alternative depreciation schedules that accord with clause 6.5.5(b) of the NER. The regulatory depreciation amount approved in this final decision is $1,321.2 million ($ nominal) for the 2025–30 regulatory control period. The reasons for our final decision are set out in Attachment 4. For metering, our final decision substitutes alternative schedules amounting to regulatory depreciation for the 2025–30 regulatory control period of $41.7 million ($ nominal). This is discussed in Attachment 20.
In accordance with clause 6.12.1(9) of the NER, the AER makes the following final 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: • We will apply version 2 of the EBSS to Ergon Energy in the 2025–30 regulatory control period. Our reasons are set out in Section 3.2 of this Overview and Attachment 8. • We will apply the CESS as set out in the 2023 Capital Expenditure Incentive Guideline to Ergon Energy in the 2025–30 regulatory control period. Our CESS determination for the 2025–30 regulatory period is a decrement of $579.5 million. The reasons for our final decision are consistent with those set out in section 3.1 of this overview and Attachment 9 of our draft decision. • We will not apply the ESIS for the 2025–30 regulatory control period. • We will apply our STPIS version 2.0 (including the customer service component) to Ergon Energy for the 2025–30 regulatory control period. Our reasons are set out in section 3.3 of this Overview. • We will apply the DMIS and DMIAM to Ergon Energy for the 2025–30 regulatory control period. Our reasons are set out in section 3.4 of this overview. • 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 section 3.3 in the overview.
In accordance with clause 6.12.1(10) of the NER, the AER's final decision is that all other appropriate amounts, values and inputs are as set out in this final determination including attachments.
In accordance with clause 6.12.1(11) of the NER and our framework and approach paper, the AER's final 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

Constituent component
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 final decision are set out in Attachment 14.
In accordance with clause 6.12.1(12) of the NER and our framework and approach paper, the AER's final 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 final 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 final 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 final decision are set out in Attachment 14.
In accordance with clause 6.12.1(14) of the NER the AER's final decision is to apply the following pass through events to Ergon Energy for the 2025–30 regulatory control period in accordance with clause 6.5.10: • Insurance coverage event • Insurer’s credit risk event • Terrorism event • Natural disaster event These events have the definitions set out in Attachment 15 of our 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 final decision is to refuse to approve the tariff structure statement proposed by Ergon Energy. The AER has amended the proposed tariff structure statement to the extent necessary – as described in Attachment 19 - to enable it to be approved in accordance with the NER. The reasons for our final decision and amendments are set out in Attachment 19.
In accordance with clause 6.12.1(15) of the NER, the AER's final decision is that the negotiating framework as proposed by Ergon Energy will apply for the 2025–30 regulatory control period. The reasons for our final decision are set out in section 5.2 of this overview and Attachment 17 of our draft decision.
In accordance with clause 6.12.1(16) of the NER, the AER's final decision is to apply the negotiated distribution services criteria published in February 2024 to Ergon Energy. The reasons for our final decision are set out in section 5.2 of this overview and Attachment 17 of our draft decision.

Constituent component
In accordance with clause 6.12.1(17) of the NER, the AER's final decision on the procedures for assigning retail customers to tariff classes for Ergon Energy is set out in section 4 of this overview and Attachment 19 of our draft decision.
In accordance with clause 6.12.1(18) of the NER, the AER's final decision is that the depreciation approach to be used to establish the RAB at the commencement of Ergon Energy's regulatory control period as at 1 July 2030 is to be based on forecast capex. The reasons for our final decision are set out in Attachment 2.
In accordance with clause 6.12.1(19) of the NER, the AER's final 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 final decision are set out in Attachment 14.
In accordance with clause 6.12.1(20) of the NER, the AER's final 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 final decision are set out in Attachment 14.
In accordance with clause 6.12.1(21) of the NER, the AER's final decision is to approve the connection policy proposed by Ergon Energy. Our reasons are set out in section 5.3 of this Overview. The approved connection policy can be found in Attachment 18.

7 List of submissions

We received 12 submissions in response to our draft decision and Ergon Energy's 2025–30 revised proposal. The stakeholders are listed below.[72]

Submissions from
AER Consumer Challenge Panel (CCP) Sub-Panel 30 (CCP30)
Australian Energy Council (AEC)
Electrical Trades Union of Australia (ETU) Queensland and Northern Territory
EQL Reset Reference Group (RRG)
Lighthouse Infrastructure
Lynette LaBlack
National Seniors Australia (NSA)
Origin Energy
Queensland Farmers' Federation (QFF)
Red Energy and Lumo Energy

72 Submissions are available on the AER website at https://www.aer.gov.au/industry/registers/determinations/ergon-energy-determination-2025-30/consultation-submissions-draft-decision-and-revised-proposal

Shortened forms

Terms	Definition
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARR	Annual revenue requirement
augex	Augmentation expenditure
Capex	Capital expenditure
CCP30	Consumer Challenge Panel, sub-panel 30
CER	Consumer Energy Resources
CESS	Capital expenditure sharing scheme
CPI	Consumer price index
CSIS	Customer service incentive scheme
CTG	Clearance-to-ground
CTS	Clearance-to-structure
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
Handbook	Better Resets Handbook
ICT	Information and communication technologies
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective

NER	National Electricity Rules
NPWG	Network Pricing Working Group
opex	Operating expenditure
PTRM	Post-tax revenue model
RAB	Regulatory asset base
RBA	Reserve Bank of Australia
repex	Replacement expenditure
RFM	Roll forward model
RORI	Rate of Return Instrument
RRG	Ergon Energy and Ergon Energy's Reset Reference Group
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCS	Standard control service
SMP	Statement on Monetary Policy
STPIS	Service target performance incentive scheme
TSS	Tariff structure statement
VCR	Values of customer reliability
WACC	Weighted Average Cost of Capital