Ergon Energy Network Revised Regulatory Proposal

2025-30

November 2024

ERGON ENERGY NETWORK

Part of Energy Queensland

Contact details

Manager Economic Regulation
Email: RDP2025Connect@energyq.com.au

PO Box 1090, Townsville QLD 4810
Level 6, 420 Flinders Street, Townsville QLD 4810
www.energyq.com.au

Copyright

ACKNOWLEDGEMENT

Ergon Energy Network acknowledges the Traditional Custodians of the land on which our distribution network is located, and we recognise their continuing connection to land, waters, and community.

We pay our respects to Elders past and present for they hold the memories, the traditions, the culture and hopes of Aboriginal and Torres Strait Islander peoples in Queensland. We extend that respect to all Aboriginal and Torres Strait Islander people today.

Ergon Energy Network is committed to continuing to work in partnership with First Nations people to ensure we deliver clean, reliable and smart energy supply to communities in regional Queensland in the most affordable way.

ABOUT THIS REVISED REGULATORY PROPOSAL

Ergon Energy Corporation Limited (Ergon Energy Network) is a subsidiary company of Energy Queensland Limited (Energy Queensland), a Queensland Government Owned Corporation, and is the electricity distribution network service provider (DNSP) for regional Queensland. We own, operate, and maintain the "poles and wires" that deliver power to 790,000 homes and businesses from the State's expanding coastal and rural population centres to the remote communities of outback Queensland and the Torres Strait.

To ensure Ergon Energy Network manages the electricity distribution network efficiently, we are regulated under the National Electricity Law and the National Electricity Rules (NER) by a national regulator, the Australian Energy Regulator (AER). The AER is responsible for determining the maximum allowed revenue Ergon Energy Network can recover from customers for using its network for the next five-year regulatory control period commencing on 1 July 2025 and ending on 30 June 2030 (the 2025-30 regulatory control period).

On 31 January 2024, Ergon Energy Network submitted a Regulatory Proposal for the 2025-30 regulatory control period to the AER. Our Regulatory Proposal set out the amount of funding required to build, operate and maintain the electricity distribution network in regional Queensland and the revenue we intend to collect from our customers through distribution charges. Our Regulatory Proposal was accompanied by a plain-language overview of our proposal and a range of supporting documentation, including our proposed Tariff Structure Statement (TSS).

On 23 September 2024, the AER published its Draft Decision on Ergon Energy Network's electricity distribution determination for the 2025-30 regulatory control period. This is our Revised Regulatory Proposal in response to the AER's Draft Decision. We developed this Revised Regulatory Proposal in consultation with customers and stakeholders.

Our Revised Regulatory Proposal is structured as follows:

- **Executive Summary** - provides a high-level summary of this Revised Regulatory Proposal
- **Chapter 1: Context for our Revised Proposal** - provides background information on our network and operating environment
- **Chapter 2: Customer and Stakeholder Engagement** - outlines the engagement we have undertaken since we submitted our Regulatory Proposal and provides a summary of what we have heard and how this has influenced our Revised Regulatory Proposal
- **Chapter 3: Investment Priorities** - reiterates the investment priorities for Ergon Energy Network for 2025 and beyond, and discusses the AER's Draft Decision as it relates to our investment priorities and our proposed response
- **Chapter 4: Demand, Energy Delivered and Customer Forecasts** – updates the demand forecasts developed for the 2025-30 regulatory control period
- **Chapter 5: Capital Expenditure (capex)** - sets out our revised capex plans and provides additional information
- **Chapter 6: Operating Expenditure (opex)** - sets out our revised opex plans
- **Chapter 7: Incentive Schemes** - covers the application of incentive schemes

- **Chapter 8: Annual Revenue Requirement** - updates the proposed revenue required to enable us to continue to build and maintain a safe and reliable network
- **Chapter 9: Network Tariffs and Pricing** - discusses our proposed revised network tariff structure
- **Chapter 10: Metering** – sets out our response on legacy metering services
- **Chapter 11: Alternative Control Services (ACS)** - outlines our response with respect to public lighting and other ACS, and
- **Chapter 12: Other Regulatory Matters** – briefly covers other related matters, including classification of services, control mechanisms, negotiating framework, pass through events, contingent projects and connection policy, and addresses confidentiality requirements.

We have adopted the “Accept, Modify and Justify” approach in our Revised Regulatory Proposal as follows:

- **Accept:** we are accepting the AER’s Draft Decision on the basis that the AER has accepted the forecast or proposal as set out in our Regulatory Proposal or because the substituted forecast or proposal is acceptable
- **Modify:** based on the feedback from the AER, we are modifying our proposal to either change the project scope (e.g. where an alternative option is acceptable) or vary the forecast or proposal. This includes projects or programs where new information has become available since the submission of our Regulatory Proposal in January 2024, and
- **Justify:** we are maintaining that the initial forecast or proposal as set out in the Regulatory Proposal is prudent and efficient and are resubmitting our business cases with additional evidence to justify the need.

Our Revised Regulatory Proposal must be submitted to the AER within 45 business days of publication of the Draft Decision, which is by 26 November 2024. The AER will assess our Revised Regulatory Proposal and consult with interested stakeholders before publishing its Final Determination in April 2025. We encourage our communities and customers to make submissions to the AER as part of its consultation process on its Draft Decision and our Revised Regulatory Proposal. The key steps of the regulatory determination process are set out in Figure 1.

Figure 1: Next steps

We will continue to engage with our customers and other stakeholders, including through our online engagement hub, Talking Energy, www.talkingenergy.com.au. Questions can also be directed to us by emailing RDP2025Connect@energyq.com.au.

MESSAGE FROM OUR CHAIR AND CEO

This Revised Regulatory Proposal provides additional information to enable the AER to make its final determination on our 2025-30 investment plans, which we believe are in the long-term interests of regional Queensland's electricity consumers.

Our Revised Regulatory Proposal is focused on striking the right balance between investing in the network to provide clean, reliable and smart electricity and efficiently delivering electricity services in the most affordable way. Our unwavering commitment to delivering on this objective underpins Ergon Energy Network's response to the AER's assessment of our expenditure plans for the 2025-30 regulatory control period.

We respect the AER's role as a regulator in ensuring that Ergon Energy Network invests and operates efficiently to deliver a network that meets consumer needs now and into the future. We thank the AER Board and staff for their open feedback and ongoing constructive engagement on our proposals for the five-year regulatory control period. This Revised Regulatory Proposal provides additional information to enable the AER to make its final determination on our 2025-30 investment plans, which we believe are in the long-term interests of regional Queensland's electricity consumers.

Ergon Energy Network operates one of Australia's most extensive electricity networks, serving Queensland communities across a vast region. Our network is made up of many complex components designed to work together to deliver quality and reliable electricity to homes and businesses. However, with large parts of our network having been constructed as far back as the 1970s and 1980s, many network assets are now nearing the end of their useful lives and are unreliable and at risk of failing. Our Revised Regulatory Proposal therefore further emphasises the need to invest in replacing our ageing infrastructure to manage current and emerging network risks and ensure we meet our customers' reliability, community safety and environmental expectations. The risks are simply too high to significantly lessen our focus on replacing older assets that are prone to failure. Nevertheless, we are mindful that we need to undertake this work in the most cost-effective and efficient way to maintain downward pressure on electricity prices in the long-term.

At the same time, the anticipated rate of population, economic and jobs growth across the region means that we must invest in the infrastructure to support more connections to the network and respond to increased demand for power. Our Revised Regulatory Proposal further details the funding we propose is prudent for the next five-year regulatory control period for the growing number of homes and businesses across regional Queensland who rely on us to provide a reliable electricity supply to meet their energy needs. This will include funding for investments that will reinforce areas of the network experiencing growth, support a higher penetration of renewables, and enable us to quickly restore supply to customers and communities following frequent severe weather events and natural disasters.

We will also continue to focus on facilitating customer opportunities in the energy transition. The energy system is undergoing complex, rapid and widespread change, with the proliferation of renewable energy sources targeting net zero emissions. The increased uptake of distributed energy sources, such as rooftop solar, provides significant opportunities for decarbonising the economy and empowering customers to both produce and consume energy. Our network therefore needs to have the capability and tariff structures in place to deliver for our customers.

To do our part in enabling the energy transformation, we know we must continue to increase our efficiency, execute faster and minimise our costs, so as to continue to deliver value for our customers and communities. Ergon Energy Network is focused on providing affordable electricity to support industry, economic development, employment, and affordable living. With this in mind, we will explore ways to further maximise network utilisation by targeting areas where capacity is available and collaborating with industrial businesses and local councils on their electrification projects. These may include the connection of new innovations, transport electrification projects, future data centres and industrial precincts in those targeted areas. This will lower costs for customers in the long-term and maximise use before spending on additional infrastructure.

Importantly, our Revised Regulatory Proposal has been informed by more recent targeted conversations with our customers, communities and stakeholders that builds on the engagement program undertaken in the lead up to submitting our Regulatory Proposal earlier this year. These discussions were primarily focused on the investment required to manage our ageing network, network tariffs and customer service performance measures. We sincerely thank all those who have worked with us throughout this engagement process and provided valuable input into shaping our revised plans for the next five-year regulatory control period.

While we clearly heard from our customers that they expect us to invest in the network to ensure it is safe and reliable, we also remain acutely aware of the cost of living pressures continuing to impact households and businesses across regional Queensland. Consequently, we have maintained our commitment to driving efficiency improvements and cost savings in how we deliver electricity to our customers. As a result, the estimated increase in distribution network charges for households will be limited to an average of $33 in each year of the 2025-30 regulatory control period. For most Ergon Energy Network customers, this is equivalent to the increase that will apply to South East Queensland customers due to the application of the Queensland Government's Uniform Tariff Policy and Community Service Obligation.

Overall, we are confident that the investment plans detailed in this Revised Regulatory Proposal will provide long-term benefits for electricity consumers by focusing on: delivering electricity services in the most efficient and affordable way; ensuring the safety and reliability of our ageing network; providing a well-integrated and resilient electricity network to meet future needs; and facilitating customer opportunities in the transition to renewable energies.

We appreciate and value the feedback provided to date on our investment and revenue recovery plans for 2025-30 and encourage further engagement through the next phase of the AER's consultation process. We will continue to work closely with the AER, customers and stakeholders to ensure a sustainable and affordable energy future for regional Queenslanders.

Sarah Zeljko
Chair
Energy Queensland Board

Peter Scott
Chief Executive Officer
Energy Queensland

Contents

Executive Summary

Executive Summary

This Revised Regulatory Proposal sets out Ergon Energy Network's response to the AER's Draft Decision on our revenue proposal for the 2025-30 regulatory control period. Our Revised Regulatory Proposal details our acceptance of elements of the AER's Draft Decision and provides our justifications or modifications in other areas. It also includes additional input provided by customers and stakeholders through engagement activities undertaken since our Regulatory Proposal was published in January 2024.

Our Revised Regulatory Proposal is summarised below.[1]

Chapter 1: Context for our Revised Regulatory Proposal

Ergon Energy Network is the DNSP for regional Queensland. We operate and maintain one of Australia's largest electricity networks, energising Queensland communities from our region's coastal and rural areas to the remote communities of outback Queensland and the Torres Strait. We provide services to more than 790,000 domestic and business customers, across a growing population base of around 1.5 million people.

While customers have told us their primary concern is energy affordability, our priorities and expenditure plans have also been influenced by a range of other challenges and opportunities (as discussed in Chapter 1). These include the significant ongoing electrification and continued high uptake of distributed energy resources, economic and population growth in regional Queensland and the increasing frequency and intensity of climate-related events that impact our network. Our plans have therefore sought to strike the right balance between investing in the network to provide clean, reliable and smart electricity and efficiently delivering electricity services in the most affordable way.

Chapter 2: Customer and Stakeholder Engagement

Ergon Energy Network's Regulatory Proposal was informed by the views and preferences of our customers and stakeholders through business-as-usual and targeted customer engagement. Customers and stakeholders provided valuable insights on a range of themes, including the challenges they and their communities face and on specific issues on which we sought feedback.

The AER's Draft Decision found that Ergon Energy Network's engagement fell short of the *Better Resets Handbook – towards customer-centric network proposals (Better Resets Handbook)* expectations, particularly with respect to capital investment decisions and the issue of affordability.[2]

Since submitting our Regulatory Proposal and following publication of the AER's Draft Decision, we have undertaken "Phase 5 – Finalise" of our engagement program for the regulatory reset. This further engagement was focused on the capital investment required to manage our ageing network, network tariffs and application of the Customer Service Incentive Scheme (CSIS). Feedback provided by customers and stakeholders through this engagement has been integral to the development of this Revised Regulatory Proposal.

Overall, customers have told us that they value the services we provide and how we go about keeping the lights on as well as the work we undertake to maintain the safety and reliability of our network. However, they have also told us that affordability of electricity remains their primary concern, both from a cost of living and cost of doing business perspective.

Further information on the matters discussed with customers and stakeholders and a summary of feedback provided is set out in Chapter 2.

[1] All financial values in this Revised Regulatory Proposal are in real 2024-25 dollars, unless otherwise stated.

[2] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Overview*, September 2024, p. 6.

Chapter 3: Investment Priorities for 2025-30

In our Regulatory Proposal, Ergon Energy Network identified four investment priorities for the 2025-30 regulatory control period (refer to Figure 2). These investment priorities were informed by customer input. Chapter 3 discusses the AER's Draft Decision as it relates to our investment priorities and our response in this Revised Regulatory Proposal.

Figure 2: Our investment priorities

Chapter 4: Demand, Energy Delivery and Customer Forecasts

Electricity demand forecasts used to develop Ergon Energy Network's investment plans were set out in our Regulatory Proposal. Chapter 4 provides updated forecasts using the most recent actual data and inputs to ensure that this Revised Regulatory Proposal reflects reasonable expectations of forecast demand, energy delivered and customer numbers. There has been no change in approach to our forecasting methodologies.

The updates to our forecasts have not resulted in the need for any changes to our network investment plans.

Chapter 5: Capital Expenditure

For the 2025-30 regulatory control period, Ergon Energy Network forecast in our Regulatory Proposal that $5,805.4 million (excluding asset disposals) of capital investment would be required to build and maintain our network assets, such as poles, wires, and transformers, connect new customers and invest in assets that support the network, including vehicles, depots, and information, communications and technology (ICT). On 28 June 2024, we submitted an updated capex model to the AER with an amended forecast of $5,746.9 million (excluding asset disposals) or $5,704.8 million (including asset disposals).

Ergon Energy Network's Regulatory Proposal also outlined that due to our actual capex being higher than the AER's substitute forecast from prior determinations, the AER was obligated to undertake an ex-post review of our capex. The additional capex, after taking into account the decision to self-fund additional ICT capital spend, was $1,195.0 million for the ex-post period of 1 July 2018 to 30 June 2023.

The AER's Draft Decision on the ex-post and forecast capex proposals and our response are summarised below.

Ex-post capex

The AER's Draft Decision did not accept the total additional capex of $1,195.0 million in the ex-post period and provided a substitute forecast of $598.8 million (a 50 per cent reduction). The AER noted that this substitute estimate was a placeholder, subject to Ergon Energy Network providing further information.[3]

The AER accepted the higher than forecast expenditure for connections, property, and other non-network (tools and equipment) in recognition that there were valid reasons for the increased expenditure in these capex categories.[4]

The AER's Draft Decision recognised that Ergon Energy Network had a genuine need to make capital investments beyond the AER's forecast over the current and previous regulatory control periods in response to an emerging issue with pole defects in our network. However, the AER disagreed with the magnitude of the additional expenditure.[5]

Ergon Energy Network maintains that the volume of asset replacements (in particular, poles and pole-top structures) was appropriate. Our response to the AER's feedback raised in the Draft Decision is set out in Chapter 5. We have also provided additional supporting documentation on the costs and benefits of our ex-post expenditure.

Notwithstanding our view that our ex-post expenditure was prudent and efficient (which is relevant in setting the replacement rate baseline requirement for our future forecast), Ergon Energy Network accepts the AER's Draft Decision on ex-post capex.

Forecast capex

The AER's Draft Decision did not accept Ergon Energy Network's updated forecast capex of $5,704.8 million and provided an alternative forecast of $4,188.1 million, which is 26.6 per cent lower than Ergon Energy Network's forecast. The difference is due to reduced AER forecasts for the replacement, augmentation, non-network ICT, property, fleet and capitalised overheads categories. The AER's Draft Decision is a placeholder subject to further supporting information being provided, largely around its concerns regarding aspects of replacement and augmentation expenditure. The AER accepted the proposed connections, distributed energy resources and cyber security capex forecasts.[6]

[3] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Attachment 5 – Capital expenditure*, September 2024, p. 7.
[4] Ibid, pp. 6, 42-44.
[5] AER, *Draft Decision, Ergon Energy Distribution Determination 2025 to 2030, Overview*, September 2024, September 2024, pp. vi-vii.
[6] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Attachment 5 – Capital expenditure*, September 2024, p. 17.

Ergon Energy Network's response to the AER's Draft Decision is to modify our capex forecast with a revised capex forecast of $5,011.4 million (including asset disposals). We have proposed modified forecasts for replacement, augmentation, fleet and capitalised overheads and will accept the substitute forecasts for all other remaining capex categories.

Our revised capex plans for the 2025-30 regulatory control period are set out in Chapter 5.

Chapter 6: Operating Expenditure

Ergon Energy Network proposed that $2,379.1 million in opex is required to fund the day-to-day costs required to operate and maintain our network assets. This includes inspecting, maintaining and repairing network assets, controlling vegetation growth, undertaking fault and emergency repairs and supply restoration, and providing customer service and corporate support activities.

The AER's Draft Decision accepted Ergon Energy Network's proposed opex forecast.[7]

However, because our proposed opex was based on a forecast 2023-24 base year, it has been updated in this Revised Regulatory Proposal to reflect actual data for 2023-24. Consequently, our forecast opex for the 2025-30 regulatory control period is now $2,562.9 million, a 7.7 per cent increase on our Regulatory Proposal forecast and the AER's Draft Decision.

We have made an efficiency adjustment of 7.8 per cent to the base year, applied a 1.0 per cent productivity factor and included only one step change (relating to smart meter data acquisition).

Chapter 6 sets out Ergon Energy Network's revised opex plans for the 2025-30 regulatory control period.

Chapter 7: Incentive Schemes

Through the application of incentive schemes, DNSPs like Ergon Energy Network are incentivised to run efficient businesses so that customers pay no more than is necessary for the services they require and ensure the right levels of service are delivered to customers.

For the 2025-30 regulatory control period, Ergon Energy Network proposed that the current incentive schemes, i.e. the Service Target Performance Incentive Scheme (STPIS), Efficiency Benefit Sharing Scheme (EBSS), Capital Expenditure Sharing Scheme (CESS), Demand Management Incentive Scheme (DMIS) and Demand Management Innovation Allowance Mechanism (DMIAM), should continue to apply. However, given our customers' strong views that we should not be rewarded for good customer service we proposed that the customer service component (telephone answering) of STPIS should not apply. We also proposed that the CSIS and Export Service Incentive Scheme (ESIS) should not apply to Ergon Energy Network in the 2025-30 regulatory control period.

The AER's Draft Decision accepted Ergon Energy Network's proposal relating to the incentive schemes to apply for the 2025-30 regulatory control period but did not accept the proposal to exclude the telephone answering component of the STPIS.[8]

Ergon Energy Network largely accepts the AER's Draft Decision, including the continued application of the telephone answering component of the STPIS. However, we have modified our position with respect to the application of the EBSS and propose that it should be suspended for the 2025-30 regulatory control period, for reasons set out in Chapter 7.

---

[7] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Overview,* September 2024, pp. 22-23.

[8] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Attachment 10 – Service target performance incentive scheme*, September 2024, pp. 6-8.

Chapter 8: Annual Revenue Requirement

In the Regulatory Proposal, Ergon Energy Network proposed that the total revenue required to continue to build and maintain a safe and reliable network for our customers is $7,818.9 million for the 2025-30 regulatory control period.

The AER's Draft Decision would allow Ergon Energy Network to recover $7,671.3 million from customers, which is $147.6 million lower than we proposed. This reduction is largely driven by a lower return on capital amount and reduced capex forecasts, which is partially offset by reduced negative revenue adjustments and a higher cost of corporate income tax.[9]

Chapter 8 sets out Ergon Energy Network's response to the AER's Draft Decision and proposes a revised forecast revenue of $7,952.0 million, which is $280.7 million more than the Draft Decision. The reasons for this proposed increase in revenue are related to updated opex, the proposed suspension of the application of the EBSS, revised forecast capex, and other mechanistic updates made to the calculation of the regulatory asset base (RAB).

Given our revised plans and revenues, in nominal terms, we estimate that the total annual network charges would increase by an average of:

- $55, or 5 per cent, annually for residential customers
- $127, or 5.9 per cent, annually for small business customers, and
- $4,023, or 6.1 per cent, annually for a large business connected on the low voltage network.[10]

However, due to the application of the Queensland Government's Uniform Tariff Policy and the Community Service Obligation payment of around $600 million per annum, 99 per cent of customers will see the equivalent Energex price. Therefore, on average, the increase for householders will be $33 or 4.6 per cent.

Chapter 9: Network Tariffs and Pricing

Distribution network tariffs are the charges imposed by Ergon Energy Network to recover the costs of building, operating and maintaining the distribution network.

In January 2024, Ergon Energy Network submitted its proposed TSS and Tariff Structure Explanatory Statement (TSES) to the AER with our Regulatory Proposal. These documents provided information on our proposed network tariffs for the 2025-30 regulatory control period, developed in consultation with customers and stakeholders.

The AER's Draft Decision did not approve our proposed TSS. While the AER accepted many elements of the TSS, changes were required. The fundamental change required Ergon Energy Network to shift default assignment for residential and small business customers with smart meters from time of use (TOU) demand tariffs to TOU energy tariffs, including reassigning customers currently on TOU demand tariffs to the TOU energy tariffs.[11]

[9] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025-2030, Attachment 1 – Annual revenue requirement*, September 2024, p. 6.

[10] The price impacts factor in transmission charges from Powerlink that are forecast to increase by inflation and the Queensland Government's Solar Bonus Scheme expiring on 1 July 2028. For forecast inflation, we have used a forecast of 2.85 per cent based on the AER's methodology set out in the PTRM.

[11] AER, *Draft Decision, Ergon Energy and Energex Electricity Distribution Determination 2025-2030, Attachment 19 – Tariff structure statement,* September 2024, p. 4-6.

Ergon Energy Network has accepted most elements of the AER's Draft Decision in our revised TSS. However, we have modified our proposal relating to the introduction of storage tariffs and, in response to customer feedback, propose to defer the introduction of two-way tariffs to beyond the 2025-30 regulatory control period.

Further information is provided in Chapter 9.

Chapter 10: Metering

Residential and small business customers who do not yet have a smart meter installed continue to receive metering services from Ergon Energy Network. Our metering services include meter reading, meter maintenance and meter data services for our basic accumulation meters (or "legacy meters").[12]

In the Regulatory Proposal, we proposed that the classification for legacy metering services should be changed from an ACS (i.e. user-pays) to a standard control service (SCS), with the costs to be recovered from all low voltage connected customers through network charges. We also proposed to accelerate the recovery of legacy meter depreciation to achieve full recovery by the end of the 2025-30 regulatory control period. Further, we asked that the treatment of metering services for the Mount Isa-Cloncurry network be the same as for the grid-connected network.

The AER's Draft Decision accepted the majority of Ergon Energy Network's proposal. However, it made a reduction to the annual revenue requirement (due to updated model inputs) and introduced a true-up mechanism for opex to account for uncertainty of legacy metering replacement volumes.[13]

As discussed in Chapter 10, Ergon Energy Network accepts the AER's Draft Decision on metering in this Revised Regulatory Proposal and, as requested by the AER, has provided an amended bottom-up opex model to allow for the outworking of the true-up mechanism. Based on updated model inputs, our metering revenue forecast is now $169.8 million for the 2025-30 regulatory control period, which is 0.1 per cent lower than the Draft Decision.

Chapter 11: Alternative Control Services

ACS are distribution services that are customer-specific or customer-requested services and are paid for by the customer who seeks the service, including public lighting, security lighting, connection management services, and ancillary services.

Public lighting

The Regulatory Proposal outlined Ergon Energy Network's strategy to continue the deployment of light emitting diode (LED) public lighting to achieve 100 per cent LEDs by 30 June 2030. We also proposed to fund the upfront capital cost of the conversion of Rate 1 and Rate 2 assets to LED, extend the cost recovery timeframe out to 2035 for the residual value of the remaining conventional lights and a user-pays approach for smart control devices (to be offered to customers from 1 July 2026). The proposed forecast revenue to be recovered from our public lighting tariffs in the 2025-30 regulatory control period was estimated to be $143.2 million ($, nominal).

---

[12] Prior to energy market reforms in 2017, Ergon Energy Network was responsible for the provision of metering services for all residential and small business customers. However, following those reforms, our role in the provision of metering services changed. We are now only responsible for managing and maintaining our existing fleet of "legacy meters" as they are gradually phased out and replaced by smart meters (which are the responsibility of energy retailers and metering service providers).

[13] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Attachment 20 – Metering services*, September 2024, pp. 4, 15.

The AER's Draft Decision accepted our public lighting strategy and made minor amendments to expenditure, revenue and pricing.[14]

Ergon Energy Network accepts the AER's Draft Decision with respect to public lighting.

Other Alternative Control Services

Ergon Energy Network's proposed approach to other ACS, as set out in the Regulatory Proposal, was as follows:

- for fee-based ancillary services, we proposed changes to service dimensions and a rationalisation of our suite of services
- for quoted ancillary services, we proposed new labour rates and inclusion of a margin, and
- for security lighting, we proposed to cease providing and installing new security lights.

The AER's Draft Decision largely accepted our proposals with respect to fee-based ancillary services and security lighting. The AER did not accept the proposed labour rates for all quoted ancillary services categories.[15]

Ergon Energy Network accepts the AER's Draft Decision with respect to security lighting and fee-based ancillary services. However, we have modified our proposal for quoted ancillary services and provided revised labour rates in this Revised Regulatory Proposal.

Further detail is provided in Chapter 11.

Chapter 12: Other Regulatory Matters

Our Regulatory Proposal addressed a number of other regulatory matters and requirements, including classification of services, control mechanisms, negotiating framework, pass through events, contingent projects and connection policy.

The AER's Draft Decision approved the control mechanisms, classification of services (except for the proposed reclassification of supply abolishment services to standard control), negotiating framework, nominated pass through events and connection policy to apply for the 2025-30 regulatory control period. Ergon Energy Network did not propose any contingent projects for the period.[16]

Ergon Energy Network largely accepts the Draft Decision, but requests that the AER reconsiders the proposal to reclassify supply abolishment services from ACS to SCS for public safety reasons.

Chapter 12 provides more information.

Attachments

Our Revised Regulatory Proposal is complemented by supporting documentation, including a revised TSS. These documents are listed in each Chapter.

[14] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Attachment 16 – Alternative control services*, September 2024, pp. 14-15.
[15] Ibid, pp. 7, 10, 14.
[16] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Overview,* September 2024, pp. 24-28.

A snapshot of our Revised Regulatory Proposal

Table 1: Standard control services

	2025-26	2026-27	2027-28	2028-29	2029-30
Forecast expenditures ($m, real $2024-25)					
Net capex	960.5	979.8	992.9	1,021.6	1,056.5
Opex (inc. debt raising costs)	527.6	518.6	512.7	505.1	498.9
Opening RAB ($m, nominal)	15,854.3	16,666.4	17,501.2	18,349.9	19,235.2
Revenue requirements ($m, real $2024-25)					
Annual revenue requirements (smoothed)	1,455.2	1,512.5	1,574.4	1,678.2	1,741.6
Weighted average cost of capital (WACC) (%)	5.88	5.90	5.94	6.02	6.10
X factor (%)	-4.55	-3.93	-4.10	-6.59	-3.77
Nominal increase in revenue (%)	7.27	6.67	6.83	9.25	6.51
Demand forecast 50 PoE (MW)	2,704	2,751	2,791	2,797	2,823
Customer numbers	805,074	812,032	818,852	825,521	832,019
Forecast energy delivered (GWh)	13,605	13,546	13,530	13,429	13,391

Table 2: Alternative control services

Matter	Position
Public lighting services	We will convert all existing conventional public lights to LED by 30 June 2030. We will fund the upfront capital cost of the conversion of Rate 1 and Rate 2 assets to LED, extend the cost recovery timeframe out to 2035 for the residual value of the remaining conventional lights, and support a user-pays approach for smart control devices (to be offered to customers from 1 July 2026).
Other ACS	We will cease to offer security lighting as a new installation from 1 July 2025 but will continue to maintain and operate legacy security lights. We have made changes to service dimensions for fee-based ancillary services and rationalised our suite of services by discontinuing the permutations that have had little to no uptake over the past three years. We are proposing to use revised labour rates specific to quoted services to ensure the recovery of actual costs.

Table 3: Key positions

Matter	Position
Service classification	The classifications as set out in the Final Framework and Approach (F&A) will apply but will also include the reclassification of legacy metering services as a SCS. We also propose that supply abolishment services should be reclassified from ACS to SCS.
Control mechanisms	The AER's control mechanism decision as set out in the Final F&A will apply, namely: • revenue cap for SCS, and • price cap for ACS.
Incentive schemes	The following incentive schemes as set out in the Final F&A will apply: • STPIS • CESS • DMIS, and • DMIAM. The following incentive schemes will not apply in the 2025-30 regulatory control period: • CSIS, and • ESIS. We propose that the EBSS will also not apply in the 2025-30 regulatory control period.
Nominated pass through events	The following additional nominated pass through events will apply: • insurance cap event • insurer's credit risk event • terrorism event, and • natural disaster event.
Contingent projects	We have not proposed any contingent projects.
Tariffs	Our revised TSS outlines our proposed tariff structures for the 2025-30 regulatory control period. We are proposing to: • change default assignment for residential and small business customers with smart meters from TOU demand to TOU energy tariffs, including reassigning customers currently on TOU demand tariffs to TOU energy tariffs • strengthen the peak price signal • update TOU pricing windows • introduce new controlled load tariffs and grid-scale battery storage tariffs, and • streamline existing tariffs.

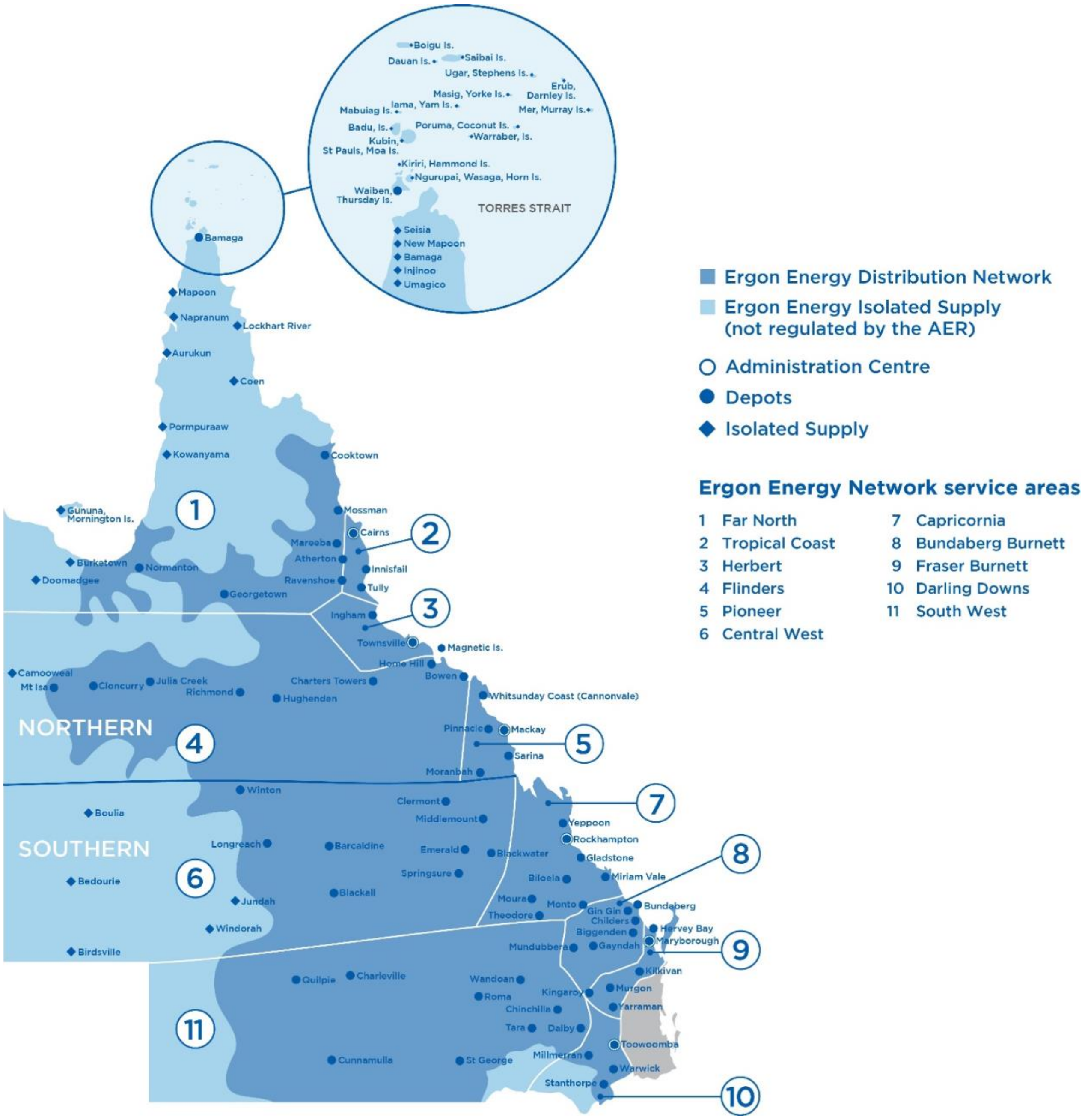
1.
Context for our Proposal

1.1 About Ergon Energy Network

Ergon Energy Network manages an electricity distribution network which supplies electricity to over 790,000 residential homes and commercial and industrial businesses across a growing population base of around 1.5 million people. Taking supply from Queensland's transmission network service provider Powerlink, we provide electricity across a vast operating area of over one million square kilometres – around 97 per cent of the State of Queensland, with a maximum demand of around 2,600 MW and delivering around 13,800 gigawatt hours (GWh) per year.

Figure 3 shows our distribution area.

Figure 3: Our service area



Our electricity network consists of 154,000 kilometres of overhead powerlines, 9,600 kilometres of underground power cables, one million power poles, 262 zone substations, 37 bulk supply substations and 98,000 distribution transformers. Based on line length, around 70 per cent of our electricity network runs through rural Queensland, typically with large distances between communities and one of the lowest population densities per network kilometre in the National Electricity Market (NEM). Ergon Energy Network has a proportionately high investment in sub-transmission assets, compared to the more urban networks, with voltage levels including 230 volt (V), 11 kilovolt (kV), 22kV, 33kV, 66kV and 132kV. It also has one of the largest Single Wire Earth Return networks in the world.

In addition, Ergon Energy Network owns and operates 33 isolated electricity networks that provide supply to around 7,000 homes and businesses in 34 remote communities in western Queensland, the Gulf of Carpentaria, Cape York, various Torres Strait Islands, and Palm Island. Except for the supply network located in the Mount Isa-Cloncurry region,[17] these isolated networks are not subject to economic regulation by the AER and are not included in this Revised Regulatory Proposal.

1.2 Our operating environment

Led by consumers' desire for lower cost and low emissions energy, our traditional poles and wires business is rapidly transforming towards a decentralised, two-way power system. The increasing number of households and businesses investing in rooftop solar generation and energy storage capabilities is driving a more complex energy system. Forecasts indicate that this trend will accelerate into the future, presenting new challenges, including rapidly declining minimum demand and significant reverse power flows (in contrast to traditional one way flows) across some parts of the distribution network, as well as system security, stability and operational risks.

The energy system has been undergoing complex, rapid and widespread change with the proliferation of renewable energy sources targeting net zero emissions. The increased availability of distributed energy resources, such as rooftop solar, provides significant opportunities for decarbonising the economy and empowering customers to both produce and consume energy.

The contextual environment of the dynamic energy industry in Queensland, and more broadly across Australia, has influenced our priorities and the development of our expenditure, revenue and tariff plans. The challenges and opportunities for Ergon Energy Network have never been greater or more complex, and include:

- **Energy affordability** - rising cost of living and cost of doing business pressures, driven by elevated inflation and interest rates, remain a core concern for our customers
- **Maximising asset utilisation** – maximising network asset utilisation before spending on additional infrastructure to meet the challenges of the energy transition and the growth in demand provides opportunities to lower costs for consumers in the long-term
- **Significant ongoing electrification** – the electrification of homes and businesses, characterised by the continued uptake of electric vehicles and other electrically powered appliances and technologies, is expected to contribute to an average growth in system peak demand of 0.8 per cent per year during 2025-30
- **Queensland's growing economy** – industry, population and jobs growth in regional Queensland is expected to result in an increase in new connections to our network of 1.6 per cent per year

[17] Section 10 of the *Electricity – National Scheme (Queensland) Act* 1997 provides that the AER is responsible for economic regulation of the Mount Isa-Cloncurry supply network.

- **Growth in the uptake of distributed energy resources** – the potential for rooftop solar to grow by 9.5 per cent annually will provide challenges in managing minimum demand on the network, while managed charging of batteries, including electric vehicles, can offer opportunities for customers and improve network utilisation
- **Decreasing daytime minimum demand** – the trend towards high penetration of renewable, decentralised generation has the potential to cause locational network reliability and security issues
- **Climate change and the environment** – the increasing frequency and intensity of weather and climate-related events impacts on the life of our assets and infrastructure, and reinforces the importance of having a resilient network and strong disaster response capability
- **Security of critical infrastructure** – greater interconnection and increased digitalisation of electricity (e.g. smart meters and smart energy management devices) will provide more information about our network and enable more use of demand response, but also increase the risk of threats to our critical infrastructure and cyber environment, and
- **Ongoing regulatory and policy change** – as the energy transition continues to gather pace, changes to the rules that regulate the NEM will impact the way we operate and manage our network.

Our customers and communities are directly impacted by our operations which are crucial to powering their lifestyles and businesses. We must therefore continue to focus on striking the right balance between investing in the network to provide clean, reliable and smart electricity and efficiently delivering electricity services in the most affordable way.

2.
Customer and Stakeholder Engagement

Key messages:

- Engaging with and listening to our customers and stakeholders is a fundamental component of our business-as-usual activities and has been integral to the development of this Revised Regulatory Proposal.
- Our Revised Regulatory Proposal has been informed by additional engagement with our customers and stakeholders.
- Customers and stakeholders shared their views on a range of themes, including the energy challenges they and their communities face, as well as on targeted issues on which we sought specific feedback.
- Overall, customers and stakeholders have told us that they value the services we provide and how we go about keeping the lights on. However, they have also told us that affordability of electricity is a primary concern, both from a cost of living and cost of doing business perspective.
- In response to customer feedback, we have sought to strike the right balance between investing in the network to provide clean, reliable, and smart electricity into the future and efficiently delivering electricity services in an affordable way that provides value to our customers and communities across regional Queensland.

2.1 Overview

Engagement with our customers and stakeholders is a fundamental aspect of our daily operations at Ergon Energy Network. For the regulatory determination process, we built upon this foundation by establishing our Customer and Stakeholder Engagement Strategy and Customer and Stakeholder Engagement Plan[18] through proactive engagement and co-design with customers, our Customer and Community Council (CCC), and various other stakeholders representing a cross-section of customer cohorts.

This chapter focuses on and discusses how, since the submission of our Regulatory Proposal to the AER in January 2024, we have continued to actively involve our customers and stakeholders in more detailed conversations that have further informed our decision-making and the development of this Revised Regulatory Proposal and TSS. This chapter covers "Phase 5 – Finalise" of our regulatory reset engagement undertaken between April and October 2024 (refer to Table 4) and focuses on the topics and issues raised in both the AER's Issues Paper published in March 2024[19] and Draft Decision published in September 2024.

More detailed information relating to our engagement activities and the insights provided by our customers and stakeholders used to inform our Regulatory Proposal is available on our Talking Energy website.

[18] These documents are available on the Talking Energy website.
[19] AER, *Issues Paper: Ergon Energy and Energex electricity distribution determinations 2025-30*, March 2024.

Table 4: Phases of engagement

PHASE	PURPOSE AND OBJECTIVE	TIMEFRAME	PURPOSE/OBJECTIVE
PHASE 1	GATHER & PLAN	By end-2022	• Gather insights from our business-as-usual engagement activities and other interactions with customers and stakeholders. • Gather insights from our existing customer research and insights program of activity and research conducted to date. • Gain a further understanding of our customer and stakeholder energy needs and engagement preferences to inform our engagement planning through a customer and stakeholder workshop/online forum. • Incorporate all insights and understanding into an engagement strategy and engagement plan outlining our approach and proposed activities to engage with our customers and stakeholders throughout the regulatory proposal process.
PHASE 2	LISTEN	Feb – Jun 2023	• Establish our key engagement structures as part of the engagement approach and plan. • Engage directly with customers and stakeholders across regional Queensland to confirm insights and understandings from Phase 1 'Gather & Plan'. • Catalogue what customers told us in our engagement conversations about their energy needs now and into the future and identify any gaps and new issues/insights provided. • Review conversations undertaken to determine key customer and stakeholder issues to inform in-depth future conversations.
PHASE 3	SHARE & EXPLORE	Jun – Aug 2023	• Explore key issues with our customers and stakeholders in-depth and analyse options, including trade-offs that may be required. • Gather insights from our in-depth customer and stakeholder conversations and evaluate how these insights and their preferences can influence the Regulatory Proposal. • Develop specific options based on customer and stakeholder preferences to be incorporated into our Draft Plan.
PHASE 4	TEST & REVISE	Sep 2023 – Jan 2024	• Engage with customers and stakeholders on our Draft Plan and test options outlined. • Explore any additional 'trade-offs' that may be required around preferences and seek common agreement where possible. • Incorporate feedback to Draft Plan and additional insights and preferences provided into Regulatory Proposal. • Submit Regulatory Proposal to the AER.
PHASE 5	FINALISE	Apr - Oct 2024	• Evaluate AER Issues Paper on our Regulatory Proposal. • Engage with customers and stakeholders to provide information required in informing their response and submissions to the AER Issues Paper consultation. • Evaluate customer and stakeholder feedback to the AER Issues Paper and further engage with customers and stakeholders to clarify the insights and feedback they provide through the AER Issues Paper consultation. • Consider all insights and feedback received to finalise our Revised Regulatory Proposal. • Submit Revised Regulatory Proposal to the AER.
PHASE 6	FUTURE	Apr 2025	• Conduct lessons learned exercise with our customers and stakeholders to inform our engagement activities going forward. • Implement 2025-30 Regulatory Proposal plans. • Monitor and evaluate delivery effectiveness, including reporting on progress against meeting our customer and stakeholder expectations and continually engage with them as part of business-as-usual engagement practices.

2.2 Our response to the AER's Draft Decision

The AER's Draft Decision sets out its views on Ergon Energy Network's customer engagement process for our regulatory determination. The AER concluded that, overall, our engagement fell short of what is expected under the *Better Resets Handbook*.[20] A key concern was that discussions on capex were mainly confined to our Reset Reference Group (RRG) and that we did not engage with customers on this key area of our proposal (i.e. our engagement was limited to informing stakeholders about our capex investment plans). Further, the AER found that while the issue of affordability raised by customers was a key theme of our proposal, the absence of meaningful, comprehensive consultation on future investment decisions with end-use customers meant that the issue of affordability was unable to be fully considered.[21]

We acknowledge that our engagement started late and consequently had a narrow scope as a result. The focus for our Regulatory Proposal was on engaging with customers in the time available to us on those areas where they could meaningfully impact our proposals. Key areas where customers influenced our Regulatory Proposal were the choice to not have a CSIS, to remove the customer service (telephone answering) component of the STPIS, and to build up pace in our network tariff reform journey. We note that the AER did not accept our customers' recommendation to remove the customer service (telephone answering) component of the STPIS[22] and, while it did accept customer decisions around some of our network tariff parameters, it did not accept our proposed default tariffs for residential and small business customers.[23] This was disappointing considering our customers' and Network Pricing Working Group's (NPWG's) support for these tariffs.

To address concerns about our lack of engagement on capex, we further engaged with our Voice of the Customer (VOC) Panel, asking them for their views on a major component of our network capex (i.e. our augmentation expenditure). We understand that, at this stage of the process, this engagement cannot be as fulsome as we would like but we are confident that this engagement will lay the foundation for a stronger focus on genuinely engaging with our customers on the underlying drivers of our expenditure and the long-term price outcomes for consumers going forward.

To achieve our long-term engagement goals, we have revised our Customer Strategy which will be a key enabler to realising the Energy Queensland 2032 Corporate Plan, in particular the strategic objectives centred around "Experience Excellence". The Customer Strategy incorporates feedback from our Customer Engagement Review and our CCC and RRG, which will result in Ergon Energy Network doing a number of things differently to enhance our customer engagement capability. The strategy has a principles-based approach, including the principles of *Know our customers, Empower our customers, Make it easy* and *Collaborate to deliver value*. Initiatives and a road map that underpins the Customer Strategy are under development.

Ergon Energy Network has committed to establishing a new framework through which issues pertaining to the regulatory reset process, including our investment and revenue recovery plans and related performance, will be discussed on an ongoing basis with customers and stakeholders. The Customer and Stakeholder Engagement Framework, which supports our refreshed Customer Strategy, was developed in response to our learnings from the 2025-30 Regulatory Proposal customer and stakeholder engagement process. This Framework, recently consulted on with our

[20] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Overview*, September 2024, p. 6.
[21] Ibid, p. 6.
[22] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Attachment 10 – Service target performance incentive scheme,* September 2024, p. 6.
[23] AER, *Draft Decision, Ergon Energy and Energex Electricity Distribution Determination 2025 to 2030, Attachment 19 - Tariff structure statement,* September 2024, p. 5.

CCC, provides for the establishment of sub-committees of our CCC to facilitate breadth and depth of discussion, and disclosure and exploration of our strategic and operational plans. The sub-committees will be sponsored by the relevant Executive or General Manager in the areas of, “Grid of the Future”, “Customer Service and Digital”, “Tariffs and Affordability” and “Asset Management, Resilience and Safety” (subject to further consultation) and will see regular and continuous disclosure of critical information, including asset management plans and projects. In addition, the new CCC will include an independent Chair drawn from the Council membership. This structural change was prompted by lessons learned through the 2025-30 Regulatory Proposal program of work and review of the Customer Strategy, including analysis of approaches by other DNSPs.

Importantly, the new Framework will establish a standing VOC Panel whose membership will be drawn from across our customer base to enable direct input from end-use customers, in addition to that obtained from other customers and stakeholders through the main CCC. The new enduring VOC panel of Queenslanders will be constituted and will see a group of Queenslanders that have been through a capacity building program remain as a regular sounding board for initiatives and take part in our regular disclosure program. This underscores an enhanced commitment to engagement in alignment with the IAP2 Spectrum of Public Participation to ensure consumers are consulted with on a range of issues, with a goal of consumers having more influence at the upper “empower” end of the IAP2 spectrum. We will, in line with the *Better Resets Handbook*, encourage consumers to test assumptions and processes that underpin our operations.

Recruitment of new CCC members and additional VOC members will commence in 2025.

2.3 Engagement activity for “Phase 5 – Finalise”

Our “Phase 5 – Finalise” engagement focused on revisiting some of the topics and issues on which we engaged in Phases 1 – 4 and exploring some new topics and issues following feedback from customers and stakeholders on our Regulatory Proposal, including from the AER, Consumer Challenge Panel (CCP) and RRG. This feedback was either provided directly to us or through written submissions in response to the AER’s Issues Paper.

The release of the AER’s Draft Decision provided another opportunity to consult with customers and stakeholders to further test, refine, and eventually finalise our investment and revenue recovery plans for the 2025-30 regulatory control period as set out in this Revised Regulatory Proposal. The sections below provide a summary of the engagement activities undertaken through “Phase 5 – Finalise”, the issues discussed, and insights obtained.

2.3.1 Customer and Community Council

The CCC includes a range of organisations that represent the interests of our customers and communities across Queensland. It has played a key role in advising on our approach to engagement by providing a sounding board for our investment and revenue recovery plans during the different phases of engagement. Many CCC members also hold positions on or attend some of our other engagement mechanisms, including the RRG, NPWG, Agriculture Forum, Public Lighting Forum and Energy Academy (electrical contractor forum). The CCC’s involvement in these discussions provided an important linkage between the topics and issues explored in conversations across the different groups and interpretation of the insights provided.

During “Phase 5 – Finalise” the CCC met three times - in April, June and November 2024. At each of its meetings, the CCC was updated on the insights provided by customers and stakeholders through our other engagement activities and how we were considering them in our evolving thinking and decision-making on our investment and revenue recovery plans outlined in this Revised Regulatory Proposal.

A key contribution of the CCC during the “Phase 5 – Finalise” engagement was to work with Ergon Energy Network to develop a suite of customer service performance measures. This suite of measures was developed based on the insights and preferences provided by our VOC Panel participants on the CSIS and customer service. The CCC assisted Ergon Energy Network in identifying suitable performance measures and metrics to socialise with the VOC Panel as part of our commitment to improving transparency in our customer service performance. Further information on the outcome of the CSIS and related customer service performance measures discussion with the VOC Panel is provided in section 2.3.3.

2.3.2 Reset Reference Group

Throughout “Phase 5 – Finalise” of our engagement plan, we continued to engage with the RRG. The RRG's primary purpose during the engagement process has been to engage in constructive collaboration with Ergon Energy Network to develop and execute our Customer and Stakeholder Engagement Plan, and to challenge us on our approach to investment and revenue recovery matters in the interests of ensuring positive outcomes for customers.

Following our Phases 1 - 4 engagement activities, the RRG told us that although they believed the engagement we undertook to develop the Regulatory Proposal fell short of expectations, they did recognise that Ergon Energy Network was committed to engaging with customers and stakeholders and acknowledged the positive role our Board and Executive played in our engagement activities. The RRG further advised that they believed there was room for improvement going into “Phase 5 – Finalise” and encouraged us to provide more time and resources for our engagement activities. In particular, the RRG recommended that more pricing information should be provided to customers and stakeholders to assist them in making value judgements in relation to the engagement topics. Furthermore, the RRG told us they believed that our “Phase 5 – Finalise” engagement provided an opportunity to expand our conversation with customers to cover important topics, such as capex, that had not been engaged on prior to the submission of our Regulatory Proposal. This feedback was actioned through engaging with the VOC Panel (discussed in section 2.3.3).

Building on its observation of our engagement activities, we continued to meet with the RRG regularly to develop our engagement activities for “Phase 5 – Finalise”. In particular, our key engagement mechanisms centred on the VOC Panel and NPWG, as discussed below.

Input on the technical aspects of our proposal provided by the RRG throughout “Phase 5 – Finalise”, including feedback provided in the “technical report” submitted as part of the AER’s Issues Paper consultation,[24] have been considered by Ergon Energy Network alongside all other customer and stakeholder feedback and used to inform the decisions outlined in this Revised Regulatory Proposal.

2.3.3 Voice of the Customer Panel / Customer Focus Group

As part of our continued customer engagement, we reconvened the VOC Panel in both August and October 2024, with the sessions independently facilitated by engagement specialists MosaicLab. The VOC Panel, originally established in 2023, has been an instrumental component of our customer engagement, providing an important mechanism through which we were able to obtain insights from across our diverse residential customer base in regional Queensland. These insights were integral to the development of our Regulatory Proposal and this Revised Regulatory Proposal.

---

[24] Reset Reference Group, *Engagement Report for the 2025-2030 Ergon Energy Regulatory Proposal*, March 2024, available on the AER’s website.

To improve efficiency during “Phase 5 – Finalise” we combined our Customer Focus Group participants from previous engagement phases with the VOC Panel to ensure we maximised the number of end-use customers participating in the engagement process and our ongoing conversations. A total of 29 end-use residential customers participated in the online August and October 2024 VOC Panel sessions across two full days. These customers provided their insights into how Ergon Energy Network should plan for the future, while providing affordable services that meet changing customer and community needs.

The VOC Panel session in August 2024 provided an opportunity to update participants on how their insights and recommendations (from both the VOC Panel and Customer Focus Group) influenced our investment and revenue proposals. Importantly, and as recommended by the RRG, we shared customer impacts around pricing in terms of the year-on-year likely price increases for customers over the 2025-30 regulatory control period based on our investment plans. The session also enabled us to discuss measures Ergon Energy Network proposes to adopt to limit those price increases, with customer concern around affordability and cost of living pressures in mind.

The August 2024 VOC Panel also provided the opportunity for Ergon Energy Network to update participants on our position on the CSIS and discuss customer preferences around openness and transparency in customer service performance measures. Participants provided input into the key services and related measures they considered were important to form part of a new Customer Service Performance Measures Scorecard to be introduced by Ergon Energy Network at the commencement of the 2025-30 regulatory control period.

A key focus for the August and October 2024 VOC Panel sessions was engaging with customers on the capex required to manage the ageing network in regional Queensland. In August, we explored our proposed replacement expenditure investments, primarily focused on our proposed pole and pole top structure replacement plans to ensure the provision of a safe and reliable network, as well as the associated costs and price impacts for customers. Following publication of the AER’s Draft Decision, the October 2024 VOC Panel session focused on the outcomes of the Draft Decision, especially as it pertained to the replacement of those network assets. In addition, the October VOC Panel session covered pricing impacts within the context of affordability, network tariffs, the CSIS and customer service performance measures. This provided Ergon Energy Network the ability to test and refine our thinking on key issues in relation to our proposed capex within the context of the AER’s Draft Decision with our VOC Panel participants.

In summary, VOC Panel participants told us the following:

- **Affordability:** participants generally understood and were accepting of our proposed investment plans over the 2025-30 regulatory control period and the associated year-on-year customer pricing impacts. However, noting that affordability and cost of living pressures were still of concern to customers, they have an expectation that Ergon Energy Network will continue to focus on efficiency and prudent investment to reduce costs where possible
- **Network tariffs:** participants appreciated there were mixed views on the pace of change around tariff reform, particularly with respect to the introduction of two-way pricing. Notwithstanding which tariffs are approved, participants considered that customer choice in network tariffs is important. Further, they were of the view that education and awareness is of vital importance to enabling customers to make informed network tariff choices and energy solution investments where practical and possible

- **Managing an ageing network:** participants expect Ergon Energy Network to consider prudent investment in managing our ageing assets, balancing the costs of investment in the 2025-30 regulatory control period against future costs if asset replacement programs, in particular those relating to poles and pole top structures, were delayed into the future. They made it clear that they expect safety and network reliability performance to be maintained, and
- **CSIS and Customer Service Performance Measures:** participants remain opposed to the concept of the CSIS, but generally accepted the AER's Draft Decision in regard to maintaining the telephone answering component of the STPIS. This view was based on Ergon Energy Network's commitment to publishing a new Customer Service Performance Measures Scorecard independently of the regulatory determination process. This scorecard will provide a performance report on the services that VOC Panel participants told us were important to them, namely: Customer Contact: Call Centre (interactions); Customer Contact: Self-serve Channels (portal and website); Power Outages (planned and unplanned); Connections (offer made and supply available); and Complaints (handling and resolution).

An overview of the insights provided by VOC Panel participants on these issues is available on our Talking Energy website.

More information on how these insights have informed the different elements of this Revised Regulatory Proposal is provided in subsequent chapters.

2.3.4 Network Pricing Working Group

During our "Phase 5 – Finalise" engagement, and in response to customer and stakeholder feedback, we took the opportunity in February 2024 to refresh and renew our NPWG membership. The aim was to broaden the customer and stakeholder base represented in the NPWG ahead of further network tariff reform-related discussions to inform this Revised Regulatory Proposal and associated TSS. Through an expression of interest process, we extended the NPWG membership beyond that of the RRG and CCC members to include other interested parties representing not only our residential and business customers, but also energy retailers and energy industry professionals.

The refreshed NPWG, which was independently facilitated by MosaicLab, met five times between April and October 2024 and was tasked with:

- reviewing the TSS that had been developed with insights provided by the previous NPWG members and other customer and stakeholder engagement on network tariffs conducted throughout 2023, including with the CCC, Agriculture Forum, VOC Panel, Large Customer Forum and Public Lighting Forum
- considering the network tariff-related customer and stakeholder submissions received and outputs from the AER's Issues Paper consultation
- considering the AER's Draft Decision on the TSS, and
- reaching consensus, where possible, on key elements pertaining to the issues identified as part of the outcomes of the AER's Issues Paper consultation, and ultimately, the network tariff reform and tariff structure-related elements of the AER's Draft Decision.

Subsequently, the NPWG conversations through "Phase 5 – Finalise" explored the following network tariff-related topics and issues in depth:

- load control tariffs and the Queensland Electricity Connection Manual (QECM)

- dynamic connections and two-way tariffs
- storage tariffs and the level of fixed charges
- TOU energy tariffs for customers consuming 100-160 MWh per annum, and
- demand tariffs and their appropriateness as the default tariffs for residential customers.

A summary of agreed positions on each of the issues outlined above from the NPWG session held in October 2024 is provided in the TSES.

2.3.5 Large customers (including commercial and industrial)

We continued to engage with large customers (including commercial and industrial) across the different large customer classifications, including our Standard Asset Customer (SAC) – Large, Connection Asset Customer (CAC) and Individually Calculated Customer (ICC) base.

Learning from our engagement with large customers during Phases 1 – 4, our "Phase 5 – Finalise" engagement with large customers focused on the key issue they identified was of primary interest to them, i.e. network tariffs.

Additionally, our engagement approach during "Phase 5 – Finalise" took the form of more individualised contact where all large customers were communicated with and provided an opportunity to engage with Ergon Energy Network through individual one-on-one discussions. These discussions were intended to enable large customers to explore their business operations now and into the future, raise any specific issues of concern with our Regulatory Proposal and, importantly, discuss individual customer impact based on the network tariffs proposed for different customer classifications. This individualised, one-on-one approach to engagement enabled a depth of conversation with those large customers who took up the offer of engaging with us that could not be explored in an open forum due to commercial-in-confidence considerations.

Although the specific details of those discussions remain commercial-in-confidence, at a summarised high-level, our large customers continue to tell us that affordability and the cost of electricity is a key component and consideration in their overall competitiveness and costs of doing business. Energy costs, along with other considerations, continue to influence their decisions around future investments in both their general business operations and in potential new energy solutions to manage their energy use. Importantly, our large customers highlighted that early notification of price impacts and future forecasting relating to pricing impacts of network tariffs is key to assisting them in both their short to medium-term budget-setting process and medium to long-term investment decision-making.

See the TSES for more information on how the insights from large customers have informed our plans for network tariff reform and the 2025-30 TSS.

2.3.6 Public lighting forum

Through "Phase 5 – Finalise" we held three separate Public Lighting Forums - in February, March and October 2024 - to further engage our public lighting customers and stakeholders on both regulatory determination and other business-as-usual engagement topics. The sessions provided Ergon Energy Network with the opportunity to update participants on the public lighting-related proposals submitted to the AER in our Regulatory Proposal in January 2024, the AER's Issues Paper consultation (including the public lighting issues raised and the process for customers and stakeholders making submissions to the AER) and the AER's Draft Decision regarding public lighting matters.

2.3.7 Other engagement activity

As part of our business-as-usual engagement activities we have also continued to engage with other customers and stakeholders through a wide range of activities in addition to those outlined above. We have continued to engage and receive insights from local councils, community representatives, Agriculture Forum members, Demand Flexibility and Innovation Working Group members, electrical contractors and other industry professionals, energy retailers and developers.

Additionally, our customer research and insights program, which includes surveying customers in relation to customer experience, customer satisfaction and trust, continues to provide us with rich insights on our service performance and what customers need and expect in terms of service delivery and in interacting with our business.

Our Queensland Household Energy Survey 2024,[25] conducted in March and April 2024, has provided valuable insights into our residential customers' perceptions around energy in general and, more specifically, their perspectives on energy affordability, their energy behaviours and, importantly, their energy-related purchasing intentions (e.g. solar PV, electric vehicles, and battery storage) both presently and in the next three to 10 years.

The insights from these other engagements, combined with our bespoke regulatory engagement activities outlined above, have been blended to provide a holistic view of what our customers and stakeholders have told us is important to them.

2.3.8 Engagement activity summary

Table 5 provides an overview of the engagement activities undertaken with our customers and stakeholders over the different phases of engagement identified in our Customer and Stakeholder Engagement Plan.[26] Collectively, the conversations had with our customers and stakeholders through those engagement activities and the rich insights they provided have evolved our thinking and proposals outlined in this Revised Regulatory Proposal.

Table 5: Overview of customer and stakeholder activity (Phases 1 – 5)

Stakeholder	How – Engagement Activity	Phase 1 Gather & Plan 2022	Phase 2 Listen Feb-May 2023	Phase 3 Share & Explore Jun-Jul 2023	Phase 4 Test & Revise Oct-Nov 2023	Phase 5 Finalise Apr-Oct 2024
CUSTOMER ADVOCATES						
Residential and Business Advocates	Customer & Community Council	✓	✓	✓	✓	✓
	Reset Reference Group	✓	✓	✓	✓	✓
	Network Pricing Working Group			✓	✓	✓
Agriculture Sector	Agriculture Forum	✓	✓	✓	✓	✓
Developer Representatives	Urban Development Institute of Australia (UDIA) – Regional Committee	✓	✓	✓	✓	✓

[25] Available on the Queensland Household Energy Survey website.
[26] Available on the Talking Energy website.

Stakeholder	How – Engagement Activity	Phase 1 Gather & Plan 2022	Phase 2 Listen Feb-May 2023	Phase 3 Share & Explore Jun-Jul 2023	Phase 4 Test & Revise Oct-Nov 2023	Phase 5 Finalise Apr-Oct 2024
Local Government and Department of Main Roads and Transport	Public Lighting Forum	✓	✓	✓	✓	✓
COMMUNITY STAKEHOLDERS						
Community Stakeholders	Queensland Energy and Jobs Plan Roadshows *(Note: Ergon Energy Network speaker at roadshows)*	-	✓	-	-	-
	Energy Queensland Board Stakeholder Events	✓	✓	✓	✓	✓
Local Councils	Area Manager meetings with local council representatives	✓	✓	✓	✓	✓
Local Councils/ Community	Disaster Planning Work Groups – Distributed and Local Groups	✓	✓	✓	✓	✓
Edge of Grid Community	Microgrid Feasibility Engagement	-	✓	-	-	-
Battery Neighbours	Local Network Battery Plan Engagement	-	✓	-	-	✓
RESIDENTIAL CUSTOMERS						
Residential Customers - reliable representation of customer base	Voice of the Customer Panels	-	✓	✓	✓	✓
	Queensland Household Energy Survey 2023 and 2024 *(Note: 1,815 Ergon Energy Network customers responded in 2024)*	-	✓	-	-	✓
Residential Customers	Customer Focus Group Workshops x 2 with Customer Focus Group members joining the Ergon Energy Network Voice of the Customer Panel in Phase 5	-	-	✓	✓	✓
	Residential Customer Tariff Interviews	✓	-	-	-	-
	Residential Network Capacity Tariff Trial *(Partner: Ergon Energy Retail)*	✓	✓	✓	✓	-
Residential Customers who have had a recent interaction with Ergon Energy Network	Customer Experience Measurement Survey *(Note: Customer Satisfaction based surveys sent to customers post interaction)*	✓	✓	✓	✓	✓
Community Members	Customer Satisfaction and Net Trust Score Survey	✓	✓	✓	✓	✓

Stakeholder	How – Engagement Activity	Phase 1 Gather & Plan 2022	Phase 2 Listen Feb-May 2023	Phase 3 Share & Explore Jun-Jul 2023	Phase 4 Test & Revise Oct-Nov 2023	Phase 5 Finalise Apr-Oct 2024
Future Voices – Energy Innovators	Solar, battery, and EV owners – Perspective Gathering Workshop	-	✓	-	-	-
Future Voices – Youth	Young people - Perspective Gathering Workshop	-	✓	-	-	-
Future Voices – Community Campaign	Online campaign – Talking Energy	✓	✓	✓	✓	-
Quiet Voices – Renters	Renters (tenants) - Perspective Gathering Workshop	-	✓	-	-	-
Quiet Voices – Seniors (definition: self-funded retirees and pensioners)	Seniors - Perspective Gathering Workshop	-	✓	-	-	-
Quiet Voices – People living with a disability	People living with a disability - Perspective Gathering Workshop	-	✓	-	-	-
Quiet Voices – Life Support Customers	Life Support Customer - Perspective Gathering Workshop	-	✓	-	-	-
Quiet Voices – Culturally and linguistically diverse	Culturally and linguistically diverse - Perspective Gathering Workshop	-	✓	-	-	-
Quiet Voices – Indigenous	Indigenous - Perspective Gathering Workshop	-	✓	-	-	-
BUSINESS CUSTOMERS						
Small to Medium Enterprises (SMEs)	Small Business – Perspectives Gathering Workshop	-	✓	-	-	-
	Individual customer interviews – network tariffs	-	-	✓	-	-
	This customer cohort also represented in CCC/NPWG/ Agriculture Forum engagements (see above)	✓	✓	✓	✓	✓
Developers	Customer experience journey mapping – developers' connection process	✓	-	-	-	-
Large customers, commercial and industrial	Large Customer Forum	-	-	✓	✓	-
	Large customer individual meetings – network tariff impacts	-	-	-	✓	✓
Agriculture	Solar Soak Tariff Desktop Analysis *(Trial Partner: Bundaberg Regional Irrigators Group)*	✓	-	-	-	-

Stakeholder	How – Engagement Activity	Phase 1 Gather & Plan 2022	Phase 2 Listen Feb-May 2023	Phase 3 Share & Explore Jun-Jul 2023	Phase 4 Test & Revise Oct-Nov 2023	Phase 5 Finalise Apr-Oct 2024
	This customer cohort also represented in Customer and Community Council/Network Pricing Working Group/Agriculture Forum engagements (see above)	✓	✓	✓	✓	✓
Sugar Industry	Sugar Mill Forum	-	✓	✓	✓	-
	Individual business-to-business meetings		✓	✓	✓	✓
ENERGY PARTNERS						
Energy Retailers	Energy Retailer Meetings *(main 6 retailers in Queensland bi-monthly)*	✓	✓	✓	✓	✓
	Energy Retailer Forum *(all energy retailers)*	-	-	✓	✓	-
	Annual Energy Retailer Satisfaction Survey	-	✓	-	-	✓
Electrical Contractors	Electrical Contractor Peak Body Meetings	✓	✓	✓	✓	✓
	Energy Academy Forum *(Electrical contractors forums)*	✓	✓	✓	✓	✓
EMPLOYEES						
Energy Queensland Employees	Energy Queensland employees (all brands)	✓	✓	✓	✓	✓
	Industry Partners	✓	✓	✓	✓	✓

2.4 Engagement insights and our response

At a high-level, across each of the phases of engagement, we have consistently heard the following key insights from our customers and stakeholders:

- safety should never be compromised
- electricity affordability is a concern for many customers, both from a cost of living and business competitiveness perspective
- our customers want clear and concise information and access to energy usage data to help them make informed choices around their energy solutions, with both pricing and non-pricing options available to manage energy costs
- there is significant interest in renewables and distributed energy resources, with growing concerns around climate change fuelling customer and community expectations about the transition to a low carbon economy

- good customer service is expected, with transparency in customer service performance seen as essential to giving customers confidence in the services delivered
- our customers and communities value how we go about keeping the lights on, especially our response to severe weather events and other natural disasters, and
- the economic environment continues to bring “energy inclusion and customer vulnerability” and “economic resilience and jobs” to the foreground.

Table 6 builds on the previous energy challenges or opportunities on which we engaged with our customers and stakeholders as part of our Regulatory Proposal engagement. Specifically, it focuses on those energy challenges and opportunities engaged on during “Phase 5 – Finalise”, some revisited and others new, and outlines what customers and stakeholders told us and how we are responding through this Revised Regulatory Proposal.

Further details on the insights provided by customers and stakeholders and how they have influenced our thinking and been considered in our decision-making are addressed throughout the relevant chapters in this Revised Regulatory Proposal.

Table 6: Engagement insights and our response overview

Energy challenge or opportunity	What customers and stakeholders told us	How we are responding
Energy affordability	Affordability of electricity is of paramount concern to customers from both a cost of living and cost of doing business perspective. The energy transition impacts on customers differently depending on their circumstances (e.g. “haves” versus “have nots”). Customers are interested in having greater choice and ways to reduce their energy consumption and therefore their energy costs. Electricity prices impact on the costs of doing business and can flow through into higher prices for goods and services provided by small and large businesses.	Affordability has been a key factor in setting our investment plans and is our foremost investment priority. We are focused on spending only what is prudent and efficient so that our customers pay no more than is necessary for their electricity supply. Our proposal responds to customer concerns on affordability by driving down controllable aspects of our expenditure program without compromising the safety or reliability of the network. We will reduce our revenue by applying a 1.0 per cent productivity factor to opex and capitalised overheads, and self-fund the capital spend above forecast for ICT for the last five years (2018-19 to 2022-23). We will continue to refine our network tariffs to enable our customers to benefit from the energy transition and reduce their network bill by changing their energy consumption patterns.
Network tariff reform	Network tariff reform should proceed with equity, fairness and cost-reflectivity in mind in the design of tariff structures. Information, education and awareness for customers is key to enabling them to make informed tariff choices and behind the meter energy solution investments based on their individual circumstances.	We will continue to reform our network tariffs to provide opportunities for customers to benefit from low-cost electricity in the middle of the day so all customers can benefit from the energy transition. We will provide new network tariff options for business customers with reduced time periods for peak pricing.

Energy challenge or opportunity	What customers and stakeholders told us	How we are responding
		We are committed to exploring network tariff and energy efficiency information campaigns and support mechanisms for customers into the future through collaboration with customers, stakeholders, and industry partners. We expect that our dynamic connection offers will be widely available by July 2028, providing more options to customers around the volume of their exports from rooftop solar and battery storage.
Capex – Replacement Expenditure	Customers support prudent replacement capex to manage the ageing network in regional Queensland both now and into the future. Customers expect a reliable and safe network that provides for all customers across regional Queensland and do not want reliability and safety standards to be compromised.	We proposed a program to replace or reinforce older assets, like poles, powerlines and transformers to ensure we meet the safety and reliability expectations of our customers and communities. In response to the AER's significant reductions to replacement expenditure in its Draft Decision and considering customer sentiment that safety and reliability are a priority, we propose a revised forecast, with updated business cases, for the AER's consideration.
Customer service excellence .	Customers expect good customer service to be a "given" and do not believe schemes such as the AER's CSIS should be required to ensure good service is delivered. However, they are generally accepting of maintaining the status quo in relation to the STPIS (telephone answering component) given it already exists. Customers want ease of interaction with us through their preferred communication channels and would like to see greater channel choice and flexibility, particularly around website and portal use. Customers want timely and accurate information on a range of topics such as power outage information (planned and unplanned), and information on a range of issues, such as connections. Customers want greater transparency in customer service performance measures and such results to be made publicly available by means of holding us to account for the services we deliver. Where services do not meet minimum standards or expectations, service improvement plans should be made publicly available, and progress regularly reported.	We supported the feedback from customers and proposed that the CSIS should not apply for 2025-30, which was accepted by the AER in its Draft Decision. Given the AER's Draft Decision to retain the customer service (telephone answering) component of STPIS and following socialisation of this decision with our customers, we propose to keep the telephone answering component of STPIS for the 2025-30 regulatory control period. We will maintain our contact centre and online channels to provide choice around how customers engage with us. Independent of the regulatory determination process and requirements, we have committed to publishing a Customer Service Performance Measures Scorecard from the commencement of the 2025-30 regulatory control period focused on services that our customers have told us are important to them: Customer Contact: Call Centre (interactions); Customer Contact: Self-serve Channels (portal and website); Power Outages (planned and unplanned); Connections (offer made and supply available); and Complaints (handling and resolution).

Energy challenge or opportunity	What customers and stakeholders told us	How we are responding
Energy efficiency in public lighting	Customers support the full deployment of LED lights by 2030 due to the financial and environmental benefits. Customers generally support a user-pays approach for the deployment of smart control devices as prudent and providing access to this technology to customers while there is still uncertainty on their use as metering devices. Customers want us to consider extending the cost recovery timeframe out to 2035 for the residual value of remaining conventional public lighting.	Our co-designed public lighting strategy provides for a transition to 100 per cent LED public lighting by 2030. The AER accepted our public lighting strategy, which we will implement for the 2025-30 regulatory control period.

2.5 Supporting documentation

The following documents support this chapter:

Document Name	Reference	File name
MosaicLab - Customer Panel and Focus Groups Report August 2024	2.01	Ergon - 2.01 - MosaicLab Customer Panel and Focus Groups Report - August 2024 - public
MosaicLab - Customer Panel and Focus Groups Report October 2024	2.02	Ergon - 2.02 - MosaicLab Customer Panel and Focus Groups Report - October 2024 - public

3.
Investment Priorities for 2025-30

Key messages:

- Our customers remain concerned about the affordability of electricity.
- There were no material issues raised on our investment priorities by the AER, customers or stakeholders.
- This Chapter discusses the AER's Draft Decision as it relates to our investment priorities and our response in this Revised Regulatory Proposal.

3.1 Overview

Our Regulatory Proposal identified four investment priorities for the next regulatory control period. These priorities were informed by customer feedback from our business-as-usual and targeted engagement activities, as well as consideration of our external environment and the key challenges and opportunities Ergon Energy Network and our customers will be facing in 2025 and beyond.

There were no material issues raised with our investment priorities by respondents to the AER's Issues Paper or during our "Phase 5 – Finalise" engagement. The AER also did not provide any specific commentary on our investment priorities in its Draft Decision.

The key priorities that will drive Ergon Energy Network's investment plans for 2025-30 are as set out in Figure 4.

Figure 4: Our investment priorities

3.2 Our response to the AER's Draft Decision

3.2.1 Investment priority 1: Deliver electricity services in the most efficient and affordable way

In our Regulatory Proposal, we committed to spending only what is necessary to meet the energy needs of regional Queensland, and in so doing minimise price increases for our customers. To that end, we undertook to strike the right balance between investing into the network to provide clean, reliable and smart electricity and addressing our customers' affordability concerns.

To do our part in enabling the energy transformation, we know we must continue to increase our efficiency, execute faster and minimise our costs, so as to continue to deliver value for our customers and communities. Ergon Energy Network is focused on providing affordable electricity to support industry, economic development, employment, and affordable living. With this in mind, we will explore ways to further maximise network utilisation by targeting areas where capacity is available and collaborating with industrial businesses and local councils on their electrification projects. These may include the connection of new innovations, transport electrification projects, future data centres and industrial precincts in those targeted areas. This will lower costs for customers in the long-term and maximise use before spending on additional infrastructure.

In addition to maximising utilisation of our network and only spending what is required to meet customer needs, we proposed to self-fund additional ICT capex above the AER allowance for the period of 2018-19 to 2022-23 and apply an annual 1.0 per cent productivity factor to both opex and capitalised overheads in the 2025-30 regulatory control period to account for expected efficiency improvements and cost savings in how we deliver electricity to our customers.

The AER's Draft Decision adopted Ergon Energy Network's affordability measures but expressed concern about the level of engagement with customers and stakeholders on investment decisions and the associated issue of affordability.[27]

Since publication of the AER's Draft Decision, we have undertaken further engagement with customers and stakeholders, with a key focus on the investment required to manage our ageing network. Our recent engagement has again highlighted that electricity affordability remains our customers' primary concern, from both a cost of living and cost of doing business perspective. This is consistent with the results of the 2024 Queensland Household Energy Survey, where 59 per cent of regional customers indicated that they were highly concerned about their ongoing ability to pay their electricity bills.[28] Consequently, delivering electricity services in the most efficient and affordable way remains our foremost priority.

However, while our customers continue to make it clear that affordability of electricity is their paramount concern, they also expect us to provide a smart electricity grid and the necessary infrastructure to support increased demand, enable customer choice for distributed energy resources, such as rooftop solar systems, battery storage systems and electric vehicles, and continue to provide a safe and reliable electricity supply. These priorities continue to be reflected in our proposed five-year investment plans.

[27] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Overview*, September 2024, p. 6.

[28] The 2024 Queensland Household Energy Survey, which is available on our Talking Energy website, was completed by 1,815 Ergon Energy Network customers, with 59 per cent rating their concern around their ongoing ability to pay their electricity bills as a 7-10 on a 0-10 scale where 0 equals not concerned at all and 10 equals very concerned.

In this Revised Regulatory Proposal, we remain mindful of the need to provide electricity services in the most cost-effective and efficient way to maintain downward pressure on electricity prices in the longer-term. In addition to applying our affordability measures, our overarching aim continues to be to spend no more than is necessary to deliver on our customers' expectations.

3.2.2 Investment priority 2: Ensure the safety and reliability of our ageing network

In our Regulatory Proposal, Ergon Energy Network highlighted that network assets in parts of our distribution network in regional Queensland are ageing and at risk of failure. Replacement or reinforcement of older assets like poles, powerlines and transformers is critical to ensuring we meet the safety and reliability expectations of our customers and communities. We have invested in these essential works in recent years and proposed to continue that investment during the next regulatory control period.

The AER's Draft Decision significantly reduced our proposed funding to replace ageing network assets.[29] The decision to reduce replacement capex, which was largely based on Energy Marketing Consulting associates' (EMCa's) assessment of our cost-benefit analysis (CBA), will significantly impact our ability to ensure the safety and reliability of the network in regional Queensland. This Revised Regulatory Proposal outlines our view that we do not accept some elements of EMCa's assessment of our CBA and consider that the AER should reconsider some of its conclusions in making its Final Decision.

Ergon Energy Network sought customer and stakeholder views on the AER's Draft Decision to significantly reduce our proposed replacement capex, specifically in relation to the reductions in pole and pole top structure expenditure. Overall, customers were uncomfortable with the Draft Decision and were concerned about the potential safety and reliability risks that would result from any significant reduction in our asset replacement program.

Ergon Energy Network maintains that ensuring the safety and reliability of our network is a key investment priority and proposes a revised forecast for replacement capex to meet customer and community expectations.

3.2.3 Investment priority 3: Provide a well-integrated and resilient network to meet future needs

In our Regulatory Proposal, we set out our commitment to supporting the transition to a clean energy future in a growing economy through providing the electricity network infrastructure required to support more household and business connections, including renewable energy sources such as wind and solar. We proposed to invest in upgrading the network to meet forecast demand and improve its resilience to the impacts of climate change and increased exposure to cyber and physical infrastructure security risks. Our proposed investments would help transform the network into a more intelligent and dynamic grid to manage and enable more distributed energy resources to be connected at lower cost. At the same time, we explored opportunities to deploy stand-alone power systems (SAPS) where they are a more cost-effective and efficient alternative to building traditional poles and wires.

[29] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Attachment 5 – Capital expenditure,* September 2024, p. 3.

The AER's Draft Decision accepted our proposed connection and distributed energy resources-related capex,[30] allowing us the investment required to connect new customers to the network and ensure the efficient integration of renewables and clean energy. This investment also provides some support for improving grid visibility. Further, the AER accepted our proposed cyber security investments so that we can manage our cyber security risks.[31]

The AER did not accept our proposed forecast expenditure for improving the resilience of our network. While the AER recognised the merits of the bushfire and flood program and the mobile substation proposals, it did not accept the mobile generation and SAPS investment proposals.[32]

We have accepted the AER's Draft Decision on our SAPS investment proposal due to the current regulatory environment. Should this environment change, we will consider future options regarding SAPS.

Having a resilient network is important for regional Queensland, especially having a backup supply for when natural disasters occur. Therefore, in this Revised Regulatory Proposal, Ergon Energy Network has proposed a modified investment for mobile generation, that takes into account the AER's feedback and the revised level of replacement works we propose.

3.2.4 Investment priority 4: Facilitate customer opportunities in the transition to renewable energies

Our Regulatory Proposal highlighted that the transition to a net zero emissions future and increasing solar generation has meant that Ergon Energy Network must develop strategies to manage the challenge of low energy demand during the day, which can cause power quality issues that can be harmful to customers' electricity appliances and the network. We therefore proposed to deliver integrated solutions that will help make the best use of generation and deliver benefits and opportunities for both our customers and our network. These solutions include changing network tariffs to encourage greater energy use by our customers during periods of high solar generation that leads to exporting into the network, expanding our demand management program, and dynamic operation of the network to manage distributed energy resources more efficiently and limit the need for network investment.

While Ergon Energy Network remains committed to providing opportunities for customers to benefit from the transition to renewable energy and more options to better manage their energy costs through network tariff reform, the AER's Draft Decision did not approve our proposed TSS for the 2025-30 regulatory control period. Key elements that were not approved include our proposed new flexible load control tariffs and grid-scale storage tariffs for both low voltage and high voltage customers.[33] Our revised TSS includes modifications to our proposed tariff structures to address issues raised in the AER's Draft Decision and provides further information to enable their acceptance.

Key initiatives that work alongside network tariffs include active device management and dynamic connection arrangements. These tools allow Ergon Energy Network to manage the energy demand more effectively while offering customers cost-saving opportunities, particularly as the penetration of electric vehicles and smart appliances increases across the State.

[30] Ibid, p. 3.
[31] Ibid, p. 14.
[32] Ibid, p. 79.
[33] *Draft Decision, Ergon Energy and Energex Electricity Distribution Determination 2025 to 2030, Attachment 19 – Tariff structure statement*, September 2024, pp. 4-5.

A dynamic connection is a new connection option for solar PV, battery and electric vehicle charging installations. It allows additional excess energy to be exported at most times, while ensuring a safe and reliable electricity network is maintained at times of congestion as Ergon Energy Network can restrict their imports from or exports to the network at times of high supply or demand via dynamic control. A dynamic connection agreement will allow Ergon Energy Network to offer customers access to the network that differs from the traditional, static “firm” capacity connection. It involves a customer accepting restrictions on their imports from or exports to the network in exchange for receiving a reduction in their network bill that reflects the lower network costs (current or expected) associated with a dynamically controlled service. For our grid-scale battery storage customers, we are offering lower network charges compared to our default tariff in return for Ergon Energy Network controlling generation and load at times of constraints through dynamic connections.

4.
Demand, Energy Delivered and Customer Forecasts

Key messages:

- Our demand, energy delivered and customer forecasts have been recast using the most recent actuals from 2023-24 and other updated inputs, where appropriate.
- The forecast methodologies remain the same as applied for the Regulatory Proposal.
- The updated forecasts have no material impact on our proposed expenditure in this Revised Regulatory Proposal.

4.1 Overview

In our Regulatory Proposal, we provided forecasts for:

- **System peak demand –** a measure of the total volume of electricity required to be available for customers at a single point in time (in MW). System peak demand is used to identify future capacity constraints, a key driver of network augmentation capex
- **Minimum demand (or negative peak demand)** – a measure of when electricity usage is at its lowest and the export of energy from rooftop solar systems is at its highest. Minimum demand requires us to deploy solutions that will minimise adverse impacts on the network (including possible electricity outages) and is a key driver of demand management initiatives
- **Energy delivered** – a measure of the total energy used by all customers over a period of time (in kilowatt hours (kWh)). Energy delivered is relevant to setting network prices
- **Customer numbers** – a projection of the number of customers expected to be connected to the network (closely linked to forecast population growth). Customer numbers form the basis of both demand and energy forecasts and is a key driver of our connection capex, and
- **Growth in distributed energy resources** – a projection of growth in the uptake of electric vehicles, solar PV systems and battery energy storage systems. Growth in distributed energy resources is a key driver of our capex program and feeds into our Distributed Energy Resources Integration Strategy.

There has been no change in approach to our forecasting methodologies. However, the forecasts have been updated using the most recent actual data and inputs to ensure that this Revised Regulatory Proposal reflects reasonable expectations of forecast demand, energy delivered and customers numbers.

In summary, we project that for the 2025-30 regulatory control period:

- continued growth in the network will result in system peak demand rising by an average of 0.8 per cent annually
- the increasing penetration of rooftop solar will cause minimum demand for the Ergon Energy Network distribution area to fall by an average of 142 MW annually
- energy delivered will decrease by an average of 0.4 per cent annually
- annual average growth in customer numbers will be around 0.8 per cent, in line with expected population growth in regional Queensland

- electric vehicle volumes will increase to between 66,625 units and 144,474 units by 2030 (depending on the rate of uptake) assuming there is greater choice and cost parity with conventional vehicles
- solar PV uptake is likely to remain strong and is expected to grow by 9.5 per cent annually for the base scenario, and
- battery energy storage systems are expected to increase by 25.5 per cent annually for the base scenario as they become more economically viable.

Table 7 provides a comparison of each forecast as presented in the Regulatory Proposal and updated for this Revised Regulatory Proposal.

Table 7: Comparison of forecasts from the Regulatory Proposal and Revised Regulatory Proposal

Forecast	Regulatory Proposal	Revised Regulatory Proposal
System peak demand	1.0%	0.8%
Forecast change in minimum demand	-116 MW	-142 MW
Energy delivered	-0.2%	-0.4%
Customer numbers	0.8%	0.8%
Electric vehicle volumes	41,000 to 118,00 units	66,625 to 144,474 units
Solar PV	8.0%	9.5%
Battery energy storage systems	27.7%	25.5%

Note: All values represent annual average growth rate, except for electric vehicles volumes which represent the expected increase in units by 2030 and the forecast change in minimum demand represents the amount the minimum demand for the Ergon Energy Network distribution area is predicted to (on average) decrease by each year over the five-year period.

4.2 Demand, energy delivered and customer numbers

The historical data used to support the system peak demand, minimum demand, customer numbers and energy delivered forecasts is provided in Table 8 (with updated actual 2023-24 values) and the forecasts are provided in Table 9. The forecast data was estimated using updated inputs, where available, and the same methodology as used for the Regulatory Proposal.

Table 8: Historical data

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
Recorded peak demand (MW)	2,481	2,651	2,716	2,689	2,677	2,688	2,702	2,637	2,874
Recorded minimum demand (MW)	1,117	1,128	1,165	1,070	1,128	961	969	799	784
Customer numbers[1]	739,353	745,505	752,141	757,726	762,303	767,583	776,533	786,523	792,127
Energy delivered (GWh)	13,747	13,332	13,243	13,504	13,567	13,477	13,780	13,868	13,927

Note 1: Historical customer numbers are as per the relevant Economic Benchmarking Regulatory Information Notice (RIN) (table 3.4.2). Customer numbers represent the average number of active and de-energised National Meter Identifiers (NMIs) on the network in the relevant financial year, calculated as the average number of NMIs on the last day of the prior financial year and on the last day of the relevant financial year. Each NMI has been counted as a separate customer.

Table 9: Forecast data

	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
10 PoE forecast peak demand (MW)	3,086	3,098	3,133	3,182	3,180	3,230
50 PoE forecast peak demand (MW)	2,708	2,740	2,751	2,791	2,797	2,823
Forecast minimum demand (MW)	617	467	315	165	20	-91
Customer numbers	798,535	805,074	812,032	818,852	825,521	832,019
Energy delivered (GWh)	13,668	13,605	13,546	13,530	13,429	13,391

4.3 Distributed energy resources

Our forecasts for the amount of distributed energy resources (i.e. solar PV, electric vehicles and battery energy storage systems) in the network are updated annually and our most recent forecasts (using the same methodology as used for our Regulatory Proposal) are provided in Table 10.

Table 10: Distributed energy resources forecasts by scenario (by calendar year)

	2024	2025	2026	2027	2028	2029	2030	2031
Solar PV								
Fast Scenario (kVA)	1,491,396	1,731,018	1,976,256	2,209,582	2,436,078	2,636,827	2,846,442	3,058,264
Medium Scenario (kVA)	1,491,396	1,706,876	1,901,411	2,101,197	2,307,834	2,511,501	2,685,316	2,812,188
Slow Scenario (kVA)	1,491,396	1,691,442	1,885,941	2,071,667	2,246,748	2,416,552	2,559,648	2,689,162
Electric Vehicles								
Fast Scenario (units)	4,093	9,277	19,673	37,498	64,593	100,616	144,474	195,566
Medium Scenario (units)	4,093	6,598	10,289	15,934	25,205	40,936	66,625	103,087
Slow Scenario (units)	4,093	5,498	7,115	9,273	12,194	16,556	23,480	34,780
Battery energy storage systems								
Fast Scenario (kWh)	76,949	99,026	127,738	171,827	222,206	275,162	333,439	402,821
Medium Scenario (kWh)	76,949	90,023	107,644	142,682	183,061	230,490	280,207	328,606
Slow Scenario (kWh)	76,949	88,602	99,988	122,586	148,620	180,638	213,254	248,563

5.
Capital Expenditure

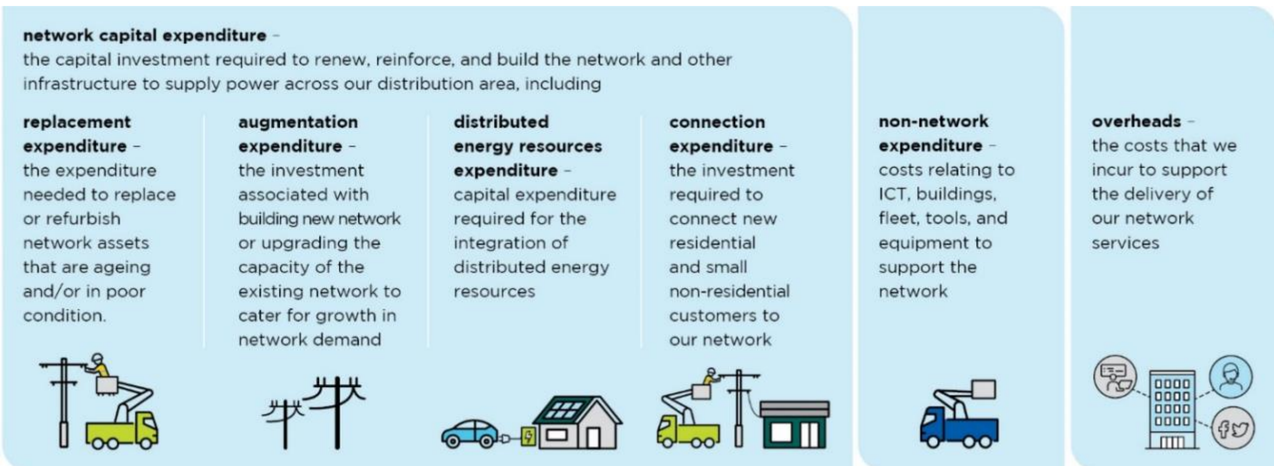
Key messages:

- The AER's Draft Decision on the ex-post review recognised that we had a genuine need to make capital investments beyond the AER's forecast. However, the AER considered the magnitude of additional expenditure was not in line with prudent and efficient decision-making. The AER provided a substitute value of $598.8 million.
- In its Draft Decision, the AER provided a substitute forecast of $4,188.1 million for Ergon Energy Network's capex (including asset disposals) for the 2025-30 regulatory control period.
- The AER's Draft Decision accepted our capex forecasts for connections, distributed energy resources, cyber security, and other non-network (tools and equipment) categories.
- The AER provided a substitute forecast for replacement, augmentation, resilience, non-network ICT, property, fleet and capitalised overheads.
- Our response to the AER's Draft Decision on the ex-post review is to accept the AER's alternate value of expenditure to be incorporated into the RAB. Notwithstanding this decision, we believe the expensed volume during the ex-post period (2018-23) for pole, pole top structures and consequential enabling components for conductors was justified.
- Our response to the AER's Draft Decision on the capex forecast is to modify our investment plans and propose a revised capex forecast of $5,011.4 million (including asset disposals). We have modified our replacement, augmentation, fleet and capitalised overhead capex forecasts. We accept the substitute forecasts for all other remaining capex categories.

5.1 Overview of the AER's Draft Decision

We remain committed to meeting the expectations of our customers and communities around the reliability, quality, resilience and safety of our network, while meeting the needs of a growing economy and population. To meet these expectations and needs, we require capital investment to build, repair and reinforce the distribution network and other infrastructure to supply electricity to our customers. Our capital investments are categorised as set out in Figure 5.

Figure 5: Capital investment categories



In our Regulatory Proposal, submitted on 31 January 2024, Ergon Energy Network forecast a capex of $5,805.4 million (excluding asset disposals) for the 2025-30 regulatory control period. We subsequently submitted an updated capex model to the AER on 28 June 2024 with an amended forecast of $5,746.9 million (excluding asset disposals). If we include asset disposals, our updated capex forecast was $5,704.8 million. This value of capex (i.e. including asset disposals) was reported in the AER's Draft Decision.

In its Draft Decision, the AER provided a substitute forecast of $4,188.1 million (including asset disposals), which represents a reduction of 26.6 per cent. This significant reduction was due to its concerns about the quality of our CBA and data in some of the business cases provided with our Regulatory Proposal. Further detail on the AER's Draft Decision for each capex category is provided in the following sections.

5.2 Our response to the AER's Draft Decision

Ergon Energy Network's response to the AER's Draft Decision is to modify our capex forecast. Our revised capex forecast is $5,011.4 million (including asset disposals) for the 2025-30 regulatory control period, which is a 12.2 per cent reduction compared to our Regulatory Proposal.

As outlined in the "About this Revised Regulatory Proposal" section of this document, we have adopted the "Accept, Modify and Justify" approach for our Revised Regulatory Proposal. Utilising this approach, our response to the AER's Draft Decision for each category of capex is summarised in Table 11. The financial values included in this table reflect updates submitted to the AER on 28 June 2024 and the re-categorisation of some expenditure by the AER. We accept most of the AER's re-categorisation except for the re-categorisation of the capex for the Clearance to Ground and Structure Program (clearance capex).

For the 2015-20 regulatory control period, Ergon Energy Network reported clearance defects as replacement expenditure. However, for the 2020-25 regulatory control period we moved these to augmentation expenditure as the underlying reason for rectification is not a condition-based replacement based on age or other criteria, but rather it is an augmentation to ensure the delivery of energy from the assets in question. For the 2025-30 regulatory control period we will continue to report this program as augmentation and have therefore included our forecast clearance expenditure under this category. For improved clarity, we have separated clearance capex out of both replacement and augmentation expenditure in Table 11.

Table 11: Summary of our response to AER's Draft Decision on capex

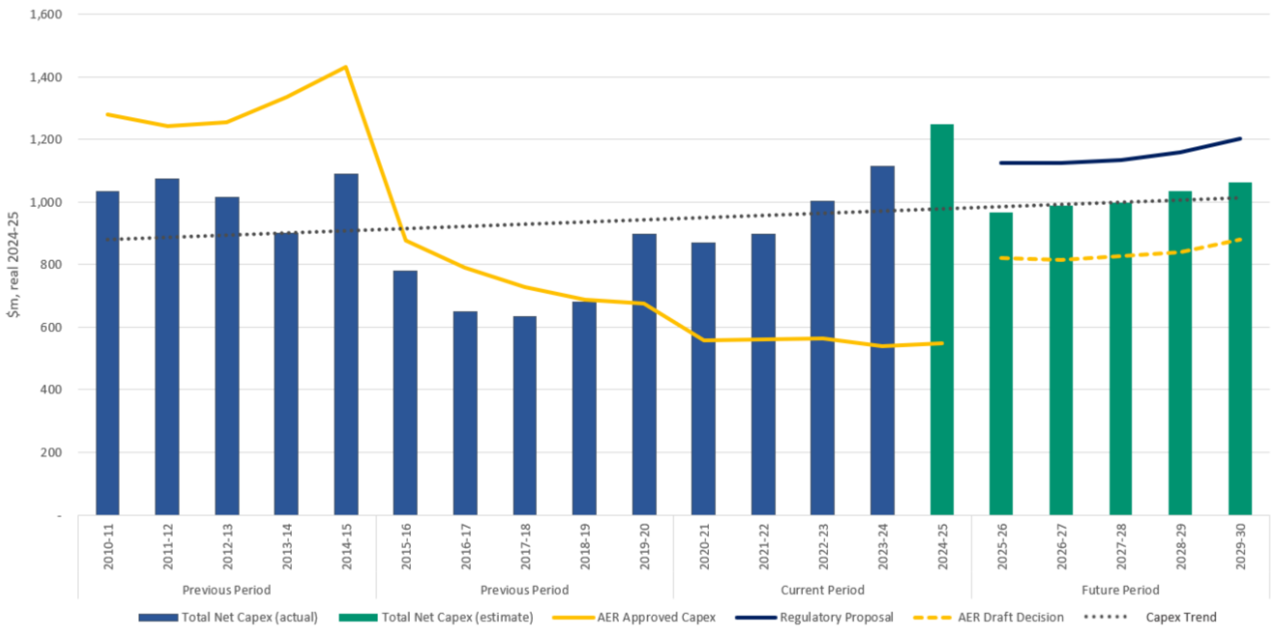
$m, real 2024-25	Regulatory Proposal	Draft Decision	Difference to Regulatory Proposal	Our Response	Revised Regulatory Proposal	Difference to Regulatory Proposal
Replacement[1]	2,537.6	1,738.6	-799.0	Modify	2,285.0	-252.6
Augmentation[2]	513.2	429.2	-84.0	Modify	489.2	-24.0
Clearance	181.1	105.7	-75.4	Modify	164.8	-16.3
Resilience	53.1	26.8	-26.3	Modify	34.6	-18.5
Distributed energy resources	63.0	63.0	0.0	Accept	63.0	0.0
Connections (net)	321.2	321.2	0.0	Accept	321.3	0.0
Non-network ICT	258.8	208.7	-50.1	Accept	208.4	-50.4
Cyber Security	53.4	53.4	0.0	Accept	53.3	-0.1
Property[3]	174.7	170.7	-4.0	Accept	170.2	-4.5

$m, real 2024-25	Regulatory Proposal	Draft Decision	Difference to Regulatory Proposal	Our Response	Revised Regulatory Proposal	Difference to Regulatory Proposal
Fleet	243.0	210.1	-32.9	Modify	222.3	-20.7
Tools & Equipment	31.7	31.7	0.0	Accept	31.6	-0.1
Capitalised overheads	1,316.1	874.4	-441.7	Modify	1,009.7	-306.4
Gross Capex[4]	**5,746.9**	**4,233.5**	**-1,513.4**	**Modify**	**5,053.4**	**-693.5**
Less asset disposals	42.1	42.1	0.0	Accept	41.9	-0.2
AER modelling adjustments	0.0	-3.4	-3.4	Modify	0.0	0.0
Net capex[5]	**5,704.8**	**4,188.1**	**1,516.7**	**Modify**	**5,011.4**	**-693.4**

Notes:
1. Excludes clearance capex.
2. Excludes clearance capex.
3. Includes property leases.
4. Totals may not add due to rounding. Does not account for asset disposals.
5. Totals may not add due to rounding.

Our proposed capex for the 2025-30 regulatory control period is 1.5 per cent less than our expected spend for the current 2020-25 regulatory control period. As illustrated in Figure 6, our forecast capex is in line with our long-term historical trend.

Figure 6: Capex between 2010 to 2030 ($m, real 2024-25)



5.3 Our response to the EMCa review on elements of capex

In assessing the prudency and efficiency of our expenditure for both the ex-post review and our forecast expenditure, the AER engaged its technical consultant EMCa to assess the economic and engineering details of elements of our expenditure. EMCa outlined its findings related to the replacement and augmentation capex for both the ex-post (2018-23) and forecast (2025-30) periods in its report titled *Ergon Energy 2025-26 to 2029/30 Regulatory Proposal - Review of aspects of proposed expenditure*. The AER placed a significant weight on the advice of EMCa in the making of its Draft Decision. This section addresses the key matters contained within EMCa's report.

To inform our response, we have sought an independent assessment of EMCa's report and invited multiple independent reviews of its findings. The findings from these independent reviews, undertaken by Aurecon, TSA Riley, and Frontier Economics, are available in Attachments 5.3.01, 5.3.02, and 5.3.03. Our response to EMCa's report and where to find more information is outlined in Table 12.

In summary, we accept that there is room for improvement in some aspects of our CBA and in the way we document some of our business cases and supporting materials. Updated materials that address the relevant feedback have been included with this Revised Regulatory Proposal (refer to Table 12 for where to find more information on supporting materials). However, there are three matters in the EMCa report that, with due respect, we do not accept. These are:

- an incorrectly specified counterfactual biased our analysis towards a preferred option (i.e. a continuation of current practice)
- the assessment period of benefits does not align with the costs; therefore we have not accurately represented the actual investment that will be incurred over the assessment period, and
- the adoption of common Energy Queensland standards, which has resulted in a higher than efficient level of pole replacements for Ergon Energy Network for both the ex-post period and the forecast expenditure for the next regulatory control period.

Our responses to the above claims are set out in sections 5.3.1 to 5.3.3.

Table 12: How we have responded to key issues identified by EMCa on elements of capex

Issue in EMCa Report	Applicability	Our response	More information
Incorrectly specified counterfactual	Forecast replacement capex.	Do not accept.	Section 5.3.1.
Assessment period of benefits does not align with the costs	Ex-post replacement capex. Forecast replacement capex.	Do not accept.	Section 5.3.2.
Adoption of common Energy Queensland standards	Ex-post replacement capex. Forecast replacement capex.	Do not accept.	Section 5.3.3.
Forecast is based on overstated historical replacement levels	Forecast replacement capex.	Do not accept. Provided supporting material to demonstrate the prudency of the ex-post capex (historical replacement rate) and that it is the appropriate base level for the forecast.	Attachment 5.5.01.
Lack of options analysis	Forecast replacement capex. Forecast augmentation capex.	Updated business cases to include more options analysis.	Attachments 5.5.02 to 5.5.23, 5.6.01 to 5.6.06, and 5.7.01.
Reconciliation between business cases, RIN categories and capex model	Forecast replacement capex.	Additional reconciliation information provided.	Attachment 5.2.02M.
Overstated assumptions	Forecast replacement capex. Forecast augmentation capex.	Updated business cases with revised assumptions and further justification.	Attachments 5.5.02 to 5.5.23, 5.6.01 to 5.6.06, and 5.7.01.
Proposed high levels of opportunistic replacement that is not prudent and efficient	Forecast replacement capex.	There are two types of consequential replacement – "enabling" and "opportunistic". We accept the AER's Draft Decision on the opportunistic replacement reduction in replacement capex. We do not accept the enabling replacement reduction and have further justified this type of replacement in revised business cases.	Section 5.5 and attachments 5.5.02 and 5.5.04.
Unit rate analysis concerns	Forecast clearance.	Updated unit rates and segmented between major and minor rectification works to improve cost-reflectivity for the differing levels of complexity in these works.	Section 5.6.1.

5.3.1 Incorrectly specified counterfactual

EMCa's position was that having incorrectly specified the counterfactual, we have biased our option selection and that "the NPVs [Net Present Values] that Ergon has calculated are not valid in confirming need because of Ergon's inappropriate definition of counterfactuals".[34] We understand that the information provided to the AER, based on independent advice, led it to adopt a benchmarking approach of our expenditure against Essential Energy for major aspects of our replacement capex. As a result of this, we sought expert advice from independent, experienced practitioners in CBA that have undertaken work for both the government and private sectors (refer to Attachments 5.3.01, 5.3.02, and 5.3.03).

It is our conclusion that, based on the advice of Aurecon, our risk-cost modelling for major replacement expenditure post implementation reviews (PIRs) and business cases was not fully assessed due to this view of an incorrectly specified counterfactual. Consequently, our risk-based economic modelling demonstrating the prudency of our actual and forecast expenditure was not considered by the AER in making its Draft Decision.

Based on independent, expert review and advice, we submit that:

- an "incorrect" choice of counterfactual does not render our CBA unusable, nor does it unduly bias any option over the other, and
- EMCa's and the AER's assessment of our specification of the counterfactual and how it biased the preferred option requires reconsideration by the AER.

Definition of "counterfactual"

EMCa believes that we have incorrectly specified the counterfactual and by doing so, have biased the analysis.[35] To assess this position, we have reviewed the AER's definition of the counterfactual in its industry guidelines for asset replacement planning. The AER's definition of the counterfactual is:

> "When analysing options for asset retirement or de-rating decision-making, the counterfactual (or base case) represents the 'business-as-usual' (BAU) cost of service. That is, the expected cost that would be incurred if the asset is not retired or de-rated, but remains in service, operated, and maintained on a BAU basis.
>
> The counterfactual represents the costs that consumers would incur if the asset continued to be operated under the standard operating and maintenance practices that the business would generally apply. This can be thought of as the costs that would arise in the case of 'doing not[h]ing materially different' from the usual practices of the business under its usual asset management practices."[36]

It is our view that when considering the full AER definition that the counterfactual should not just consider that the asset has not been retired (i.e. no replacement of assets), but also needs to consider the second paragraph, i.e. the counterfactual should be doing nothing materially different from the usual practices of the business under its usual asset management practices.

It is our usual asset management practice to replace assets when they are identified as defective, i.e. if upon inspection the asset's condition falls within certain parameters and it is deemed defective, the asset will be replaced. Considering our large volumes of ageing assets, the doing nothing materially different scenario is that the current replacement rates of our assets would

[34] EMCa, *Ergon Energy 2025-26 to 2029/30 Regulatory Proposal - Review of aspects of proposed expenditure*, August 2024, p. 29-30.
[35] Ibid, p. 28-29.
[36] AER, *Industry practice application note – Asset replacement planning*, January 2019, p. 27.

continue. In our PIRs, we utilised our historical replacement rate of assets for the counterfactual (which was significantly lower than our current rate), while for the business cases for forecast expenditure we utilised our current rate of replacement.

We put forward that our interpretation of a counterfactual option aligns with the AER's industry guidelines for asset replacement planning. We sought independent economic advice on our interpretation of the counterfactual for our replacement expenditure. The advice provided by Frontier Economics and TSA Riley includes the following:

> "Generally, the base case should be defined as the most credible state of the world in the absence of an intervention. That is, the base case should represent a 'business-as-usual' approach over time." [37]
>
> "It would be unrealistic for a counterfactual (base case) to include no capital expenditure for replacement works in the context of a portfolio of ageing assets where a duty of care exists to adhere to electrical safety standards .... EQL's decision to specify a base case in the Pole Replacement Business Case that reflects continuation of current practice (i.e. continuation of recent repex expenditure) is defendable, ..." [38]

The counterfactual and the cost benefit analysis

The further finding made by EMCa, which was referenced by the AER in its Draft Decision, is that the option chosen for the counterfactual has biased the CBA and therefore the analysis is not credible.[39]

It is our position that choosing a counterfactual provides a framework for quantifying any benefits of various intervention options. That is, the counterfactual is a reference point to calculate the most likely future costs and benefits to mitigate identified risks without an intervention against a different future of costs and associated residual risks.

As an example, a DNSP's current practice might be to replace one pole per year. However, an intervention could be to replace two poles per year. In this example, the counterfactual would be to continue replacing one pole per year and we would calculate the residual risk from this strategy. We would then model replacing two poles per year and calculate the resultant risk of having a new set of poles. The "benefits" are the different risk consequences (e.g. safety, reliability) that arise between the new risk and the counterfactual risk, while the costs are the extra pole per year that we have replaced.

From this perspective, the CBA is an incremental assessment rather than an absolute calculation. The exact specification of the counterfactual, while important to ensuring common understanding of the analysis that has been undertaken, will not impact the option or volume that maximises value to customers and can easily take several forms. The counterfactual should be common and consistent among the range of volumes considered, but more critical in determining the optimum outcome is that a full range of volumes are considered in the analysis. Our previous PIRs and business cases considered volumes higher and lower than our chosen level of replacements for the Regulatory Proposal and our counterfactual case, with the resultant NPVs being calculated and presented. So long as a full range of options have been considered, the exact specification of the counterfactual does not impact or bias which option will be the preferred option. In effect, the best

[37] Frontier Economics, *Attachment 5.3.03 - Counterfactual for Repex Business Cases*, 2024, p. 5.

[38] TSA Riley, *Attachment 5.3.02 - Review of Aspects of Ergon Energy Replacement Expenditure*, 2024, p. 5.

[39] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Attachment 5 – Capital expenditure,* September 2024, pp. 32, 49-50

option will prevail as the highest net benefit option, irrespective of the counterfactual chosen. As per the independent economic advice provided by Frontier Economics, TSA Riley and Aurecon:

> "… using the AER's preferred counterfactual would not have identified a different optimal repex option … The only exception to this rule would be if a counterfactual which was not included in the analysis … had performed better than all other options tested … Therefore, it was incorrect for EMCa to conclude that Ergon Energy's definition of counterfactuals 'biases' the DNSPs' selection of repex options."[40]

> "Even if the alternative lower spend 'Option 3 – Repex Live Scenario' was adopted as the base case, it would not invalidate EQL's current Pole Replacement Business Case CBA analysis and conclusions."[41]

> "Aurecon concludes Ergon's option analysis considered multiple credible scenarios, including industry-standard alternatives, demonstrating no bias towards preferred expenditure."[42]

Attachment 5.3.04 outlines a simple example that clearly demonstrates that the choice of counterfactual has no impact on the preferred volume of replacements and impacts only the absolute value of an NPV, while the relative difference between options remains constant.

5.3.2 Assessment period of benefits does not align with the costs

EMCa put that we had included an assessment period of 20 years for the benefits but only five years for the costs. EMCa put that:

> "Only considering five years for costs does not accurately represent the actual investment that will be incurred by Ergon over the assessment period, and further undermines the definition of the counterfactual. At a minimum, failed assets would need to be replaced for every asset class, and therefore the investment would not be zero, and this investment would impact the calculation of benefits."[43]

Our modelling includes failed asset replacements for the full 20 year analysis period, the costs that EMCa (and reported by the AER in its Draft Decision) claim are missing from our analysis. We refer to this as a "financial risk", i.e. the cost of rectifying a failed asset.

Irrespective of the correctness of our existing modelling, our replacement capex business cases now include the use of the Equivalent Annualised Cost Method, which allows a direct comparison of the cost of an asset replacement with the benefits that replacement yields. For clarity, this is an alternative way of presenting the same information as our original CBA. We are attempting to simplify the assessment so that it is clearer for external reviewers. More information on this method can be found in Attachment 5.3.04. In addition, the new business cases for pole and pole top structure replacement capex will be modified to include an assessment period of 50 years and 35 years, respectively (refer to Attachments 5.5.02 and 5.5.03).

[40] Frontier Economics, *Counterfactual for Repex Business Cases*, 2024, pp 9, 12.

[41] TSA Riley, *Attachment5.3.02 - Review of Aspects of Ergon Energy Replacement Expenditure*, 2024, p.5.

[42] Aurecon, *Attachment 5.3.01 - Independent response to EMCa's report*, 2024. p.12.

[43] EMCa, *Ergon Energy 2025-26 to 2029/30 Regulatory Proposal - Review of aspects of proposed expenditure*, August 2024, p. 54.

5.3.3 Adoption of common Energy Queensland standards for management of pole assets

A key point made by EMCa, and supported by the AER, is that Ergon Energy Network adopted Energex's pole management practices and standards, which has "led to a higher pole replacement rate, and therefore higher level of expenditure than is prudent without adequate consideration of differences between the two networks and the customers they serve".[44] In its Draft Decision, the AER outlines the differences in the Energex and Ergon Energy Network areas and why these assets should be managed differently.[45]

However, while there has been standardisation of approach to asset management across both networks where appropriate, Ergon Energy Network's pole management practice is specifically designed for Ergon Energy Network and is different to Energex's pole management practice. There are four key areas to the management of pole assets, each of which has a different approach between Ergon Energy Network and Energex:

- **Condition monitoring measurements** – we utilise six specific measurements for Ergon Energy Network, while we use only three indicators for Energex
- **Calculation of degraded pole strength** – we utilise what is known as a "Limit State Calculation" for Ergon Energy Network, while we use a "Working Stress / Factor of Safety calculation" for Energex
- **Bending result** – we have a two-stage process for both networks, but the tests we utilise in each stage are different, and
- **Calculation of degraded pole strength for compression** – this process attributes further pole stress due to having to carry a transformer. We do not include this extra factor for Ergon Energy Network, while it is included for Energex.

Please refer to Attachment 5.5.01 for further information. The different assessment approach (as described above) demonstrates that Ergon Energy Network does have a network-specific approach to managing our poles.

5.3.4 AER request for further information

Both EMCa and the AER raised issues with some data quality. In the Draft Decision, the AER requested further information around the accuracy of the data we provided and how it reconciles.[46] This request was particularly focused on project level costs and asset replacement details through the ex-post (2018-23) period. We have engaged constructively with the AER, including hosting a three-day workshop, and provided a range of information in advance of our Revised Regulatory Proposal (refer to Attachment 5.2.02). We will continue to work with the AER in advance of the Final Decision.

[44] Ibid, p.20.

[45] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Attachment 5 – Capital expenditure*, September 2024, pp. 30-31.

[46] Ibid, pp. 35-36

5.3.5 Conclusion

Ergon Energy Network appreciates the time and effort that went into investigating and analysing our ex-post and forecast capex proposals, and the opportunity to present and explain to the AER and EMCa the complexities of our network and unique challenges of operating in regional Queensland. While we do not agree with all of EMCA's conclusions on our business cases and CBA, we accept that there is room for improvement in some aspects of our CBA, including the need to provide more detail in some cases and be clearer in the way we present data.

We have engaged directly with the AER since the release of the Draft Decision and consider that we have reached an improved common understanding of our asset management practices and CBA practice. We have also updated some business cases and CBAs to reflect feedback from the AER.

We look forward to continuing to work constructively with the AER to achieve a regulatory determination that addresses the on-going challenges of ageing infrastructure while optimising customer benefits.

5.4 Ex-post review

Due to our actual expenditure being higher than the AER's substitute forecast from prior determinations, the AER was required to undertake an ex-post review of our capex.[47] The purpose of the ex-post review is to determine if our capex reasonably reflects the capex criteria, i.e. capex that is prudent and efficient,[48] and can be included in our RAB. For the opening RAB in our Regulatory Proposal, we excluded the capital spend over forecast for non-network ICT ($121.3 million). This was a key initiative under our foremost investment priority for the 2025-30 regulatory control period, i.e. deliver electricity services in the most efficient and affordable way.

The capex above the AER's substitute forecast for the ex-post review period,[49] the AER's Draft Decision and our response is provided in Table 13.

Table 13: Our response to AER's Draft Decision on ex-post capex

$m, real 2024-25	Additional Capex[1]	Draft Decision	Difference to Additional Capex	Our Response	Revised Regulatory Proposal	Difference to Additional Capex
Replacement	1,231.9	674.0	-557.9	Accept	674.0	-557.9
Augmentation	-171.8	-171.8	0.0	Accept	-171.8	0.0
Connections (net)	44.2	44.2	0.0	Accept	44.2	0.0
Distributed energy resources-related	N/A	N/A	N/A	N/A	N/A	N/A
Non-network ICT[2]	Self-funded	N/A	N/A	N/A	N/A	N/A
Property	51.7	51.7	0.0	Accept	51.7	0.0

[47] Clause 6.12.2(b) requires the AER to include in any draft or final regulatory determination a statement on the extent to which the roll forward of the RAB meets the capital expenditure incentive objective. Clause 6.2.2A provides that in certain circumstances the AER may reduce the amount by which a network business's RAB is to be increased as part of the RAB roll forward.

[48] Clause 6.4A(a) of the NER.

[49] The ex-post review period is 2018-19 to 2022-23 (inclusive).

$m, real 2024-25	Additional Capex[1]	Draft Decision	Difference to Additional Capex	Our Response	Revised Regulatory Proposal	Difference to Additional Capex
Fleet	-56.5	-56.5	0.0	Accept	-56.5	0.0
Tools & Equipment	1.1	1.1	0.0	Accept	1.1	0.0
Capitalised overheads	94.4	56.1	-38.3	Accept	56.1	-38.3
Total[3]	**1,195.0**	**598.8**	**-596.2**	**Accept**	**598.8**	**-596.2**

Notes:
1. A negative value indicates that Ergon Energy Network spent less than the AER's forecast amount for that capex category.
2. The additional capex of $121.3 million for non-network ICT will be funded by our Shareholder.
3. Totals may not add due to rounding.

The AER's Draft Decision recognised that Ergon Energy Network had a genuine need to make capital investments beyond the AER's forecast over the current and previous regulatory control periods in response to an emerging issue with pole defects in our network. However, the AER concluded that the magnitude of this additional expenditure was not in line with prudent and efficient decision-making.[50]

We acknowledge that the AER has accepted our additional capex with respect to connections, property, and other non-network (tools and equipment) in recognising that there were valid reasons for the increased expenditure in these capex categories.[51] There were only two areas where the AER had concerns about our expenditure in the ex-post period, namely replacement expenditure (primarily the consequential replacement of assets, i.e. where other assets are replaced at the same time as targeted assets, such as pole cross-arms), and the rectification of clearance defects (conductor that is closer to the ground or to a structure than the regulations specify).

While we acknowledge that the volume of consequential asset replacements was substantial, Ergon Energy Network maintains that the volume of pole and conductor consequential "enabling" replacements (e.g. pole, pole top and services type assets) was prudent and efficient. We have provided further evidence and supporting material for our replacement expenditure forecast in this Revised Regulatory Proposal. Our positions on replacement and augmentation capex forecasts are outlined in more detail in sections 5.5 and 5.6, respectively.

5.4.1 Replacement capex ex-post review

As noted in section 5.3, we challenge EMCa's conclusions relating to our CBAs for major asset categories, which we believe have led to the AER not considering the supporting justification for expenditure in the ex-post period. We believe that this has resulted in sub-optimal conclusions around the prudency and efficiency of the actual (and forecast) capex.

[50] AER, AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Overview* , September 2024, pp. vi-vii.
[51] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Attachment 5 – Capital expenditure*, September 2024, pp. 6, 42-44.

We have identified areas for improvement in our CBA modelling and have updated the modelling accordingly. We have continued to work with our data to ensure that the assumptions and modelling factors are calibrated to the latest data from the field. We maintain that the volume of asset replacements (in particular, poles and conductor “enabling” consequential asset replacements) was appropriate and that actual expenditure between 2018 and 2023 in the major replacement expenditure categories was prudent and efficient in delivering our asset safety and reliability obligations (refer to Attachment 5.5.01).

Notwithstanding that the definition of the counterfactual is not critical to the outcome of the CBA, provided a variety of options are considered, the choice of counterfactual replacement volume for the analysis undertaken for the ex-post PIRs was originally based on the historical replacement rates for that period (i.e. the PIR’s counterfactual was the pre-2018 replacement rate). Based on the AER’s feedback, we have modified the counterfactual for the forecast pole replacement capex to also be the pre-2018 replacement rate (refer to Attachment 5.5.02).

While we maintain that the volume of poles replaced in the 2018-23 period was prudent and efficient, we have accepted the AER’s Draft Decision on this element of expenditure. We request the AER consider our updated business case for the increase in replacement volumes (refer to Attachment 5.5.01).

5.4.2 Clearance ex-post review period

Our clearance program addresses breaches of clearance limits that are specified in the *Electrical Safety Regulation 2013* (Qld). These breaches occur where a live conductor is too close to the ground or too close to a structure. It should be noted that for the 2015-20 regulatory control period we reported clearance defects as replacement expenditure. However, for the 2020-25 regulatory control period we classified these as augmentation expenditure as the underlying reason for rectification is not a condition-based replacement based on age or other criteria, but rather it is an augmentation to ensure the delivery of energy from the assets in question. For the 2025-30 regulatory control period we intend to continue to report this program as augmentation. For the purposes of this Revised Regulatory Proposal, we have separately identified clearance capex due to the AER’s re-categorisation of clearance capex from augmentation capex to replacement capex, which is at odds with our usual reporting practices.

In its Draft Decision, the AER acknowledged our legal obligations under the *Electrical Safety Regulation* 2013 (Qld) to address breaches of clearance limits. The AER also accepted the volume of defect remediations undertaken during the 2018-23 period. However, it did not accept that our unit rate (i.e. the average cost to rectify each of these clearance defects) was efficient (i.e. the average cost for rectification was higher than it expected).

As with our replacement expenditure, we have accepted the AER’s Draft Decision for clearance expenditure on the basis of the volume of defect remediations completed. Our clearance business case for forecast expenditure in the 2025-30 regulatory control period outlines how we have considered the feedback provided and calculated an updated unit rate for clearance rectifications and how this relates to our revealed unit rates for the 2018-23 ex-post review period (refer to Attachment 5.6.01).

5.4.3 Conclusion

Despite our view that the majority of the capex in the ex-post period is prudent and efficient, Ergon Energy Network has decided to accept the AER's Draft Decision, which was supportive of the need for additional capital investments beyond the AER's forecast over the current and previous regulatory control periods. We will continue to work with the AER on our forecast expenditure for the 2025-30 regulatory control period and refine our modelling to demonstrate the prudency and efficiency of the actual and forecast expenditure, ensuring we maximise value for our customers.

5.5 Replacement

Ergon Energy Network replaces and refurbishes existing assets that are ageing or in poor condition to meet our reliability and safety obligations, and the expectations of our customers and communities.

Our forecast replacement capex is increasing due to ageing assets reaching the end of their serviceable lives. As discussed in our Regulatory Proposal, while we took prudent actions to extend the lives of our assets, they must now be replaced due to safety risks and reliability impacts.

The AER has not accepted our proposed forecast of $2,718.8 million[52] over five years and has instead provided a substitute forecast of $1,844.3 million.[53] This value of replacement capex includes the forecast capex for clearance.

As previously discussed, for the 2020-25 regulatory control period we began reporting clearance as augmentation expenditure as this category better reflects the underlying requirements for investment in this program. That is, it reflects that rectification of clearance to ground or clearance to structure is not a condition-based replacement based on age or other criteria, but rather it is an augmentation to ensure the delivery of energy from the assets in question. For the 2025-30 regulatory control period we intend to continue to report this program as augmentation and therefore have included our forecast clearance expenditure in category of augmentation. This also maintains consistency between our Regulatory Proposal and Revised Regulatory Proposal, which we consider is important for our customers and stakeholders.

Ergon Energy Network has modified the forecast replacement capex to a revised forecast of $2,285.0 million (excluding clearance) for the 2025-30 regulatory control period. Our response to the AER's Draft Decision on forecast replacement capex is summarised in Table 14. We have listed the clearance capex separately to provide improved clarity and enable a meaningful comparison with the AER's Draft Decision.

[52] This amount represents the net outcome of the revised replacement capex forecast submitted to the AER on 28 June 2024 plus the AER's re-categorisation of $181.0 million to replacement capex from augmentation capex and the re-categorization of $7.9 million from replacement capex to cyber security capex.
[53] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Attachment 5 – Capital expenditure*, September 2024, p.19.

Table 14: Summary of our response to AER's Draft Decision on replacement capex

$m, real 2024-25	Regulatory Proposal	Draft Decision[1]	Difference to Regulatory Proposal	Our Response	Revised Regulatory Proposal[2]	Difference to Regulatory Proposal
SCADA, Protections and Communications	132.9	90.6	-42.3	Modify	111.3	-21.7
• Grid Communications	98.6	62.2	-36.5	Modify	78.7	-20.0
• Operational Technology	15.7	9.9	-5.8	Modify	14.0	-1.7
• Relay Replacements	18.6	18.6	0.0	Accept	18.6	0.0
Distribution Transformer Replacement Business Case	152.6	118.4	-34.2	Accept	118.4	-34.1
Underground Cable Replacements Business Case	38.8	38.8	0.0	Accept	38.8	0.0
Overhead Conductor Replacements Business Case	537.8	405.5	-132.3	Modify	494.8	-43.0
Distribution Switches Business Case	88.0	70.7	-17.3	Accept	69.8	-18.2
Pole Replacements Business Case	815.1	420.5	-394.6	Modify	744.4	-70.7
Pole Top Structure Replacement Business Case	262.3	138.1	-124.3	Modify	252.6	-9.7
Service Lines Replacements Business Case	87.6	87.6	0.0	Accept	87.6	0.0
Others (inc. Substation Transformer and Switchgear)	422.5	366.8	-55.7	Accept	367.1	-55.4
Replacement capex[3]	**2,537.6**	**1,737.0**	**-800.6**	**Modify**	**2,285.0**	**-252.8**
Clearance (augmentation)	181.1	105.7	-75.4	Modify	164.8	-16.3
Replacement capex plus clearance capex[4]	**2,718.8**	**1,842.7**	**-876.1**	**Modify**	**2,449.8**	**-269.0**

Notes:
1. Values sourced from the AER Capex Model (Ergon Energy distribution determination 2025-30). Minor discrepancies exist between the summation of the disaggregated information in the AER's Capex Model and the aggregated amounts published in the AER's Draft Decision.
2. Minor differences between Draft Decision and Revised Regulatory Proposal values are due to inflation adjustment.
3. Replacement total excludes clearance capex. Totals may not add due to rounding.
4. Total includes clearance capex. Totals may not add due to rounding.

5.5.1 Our response to AER and customer feedback

Ergon Energy Network appreciates the feedback provided by the AER around those areas where further information or analysis would support it in making its Final Decision on replacement capex. In response to this advice, we have continued to refine our models and worked constructively with the AER to further explore our models with a view to demonstrating the prudency of our investments.

We have expressed to the AER our view that there is a better way to assess our replacement expenditure proposal rather than benchmarking against Essential Energy. As per our consultant's benchmarking review report (refer to Attachment 5.4.01), there are five key differences between Essential Energy and Ergon Energy Network that mean this is a problematic comparison:

- **Low strength pole population –** we have a significant population of poles that are below 3 kilonewtons (kN) in strength, with poles of this strength accounting for 25 per cent of our unassisted failures and 16 per cent of our defective poles. Our understanding is that Essential Energy does not have any poles at this low strength, and that their lowest strength is the equivalent of 8kN. We no longer install 3kN poles in our network, but we have a large population of these poles due to historical practices. Ultimately, we have a population of poles that has a significantly lower strength than the network that we have been benchmarked against
- **Design factor of safety –** in designing the network, Ergon Energy Network has historically utilised a factor of safety of 2.5 in our design, while our understanding is that Essential Energy has used a factor of 4. This results in smaller poles typically being used in the same scenario for Ergon Energy Network and a reduced tolerance to degradation of pole strength over time, which would result in higher replacements for poles in the same situation
- **Safety obligations** – the Queensland *Electrical Safety Code of Practice* 2020 requires us to meet a three-year moving average pole reliability target of 99.99 per cent per annum, while there is no such equivalent mandated target applicable in New South Wales, where Essential Energy operates
- **Pole sourcing** – the majority of poles in our network have been sourced from regional Queensland. Timber grown in sub-tropical climates results in faster growing but lower strength poles. This leads to shorter lifespans and increased maintenance needs when compared with poles grown further south, even where poles would originally be designed to meet the same nominal strength when installed, and
- **Weather –** our climate ranges from sub-tropical to tropical, with some grassland, while Essential Energy is primarily located in a more temperate and grassland climate. This results in our network being exposed to more extreme weather, larger temperature differentials, higher rainfall and humidity and flooding, which elevates the potential for rot and decay in our pole population.

Further, as outlined in section 5.3, we have concerns about some of the matters raised by EMCa in its assessment of our CBA which were subsequently relied upon by the AER in making its Draft Decision. These concerns have been supported by independent review and analysis. We therefore request that the AER considers this further information before making its Final Decision.

In addition to considering the AER's and EMCa's position on our replacement capex, we also sought and considered customer feedback. Following the Draft Decision, we engaged with our VOC Panel on the challenges of our ageing network and replacement capex proposal for poles, pole top structures (cross-arms) and overhead conductors. We sought our customers' views on the AER's Draft Decision to significantly reduce our proposed expenditure for poles and pole top structures, noting that the AER approved our overhead conductor capex forecast.

Overall, customers were uncomfortable with the AER's Draft Decision to reduce our replacement capex on pole and pole top structures. Participants expect Ergon Energy Network to consider prudent investment in managing our ageing assets, balancing the costs of investment in the 2025-30 regulatory control period against future costs if asset replacement programs (in particular those relating to poles and pole top structures) were delayed into the future.

A key take-away from this customer consultation was that customers were not only concerned about the safety and reliability impacts of significantly reduced replacement expenditure, but also disagreed with the benchmarking comparisons between Ergon Energy Network and Essential Energy, primarily due to the operating environment in regional Queensland. There was a general view that the regional nature of the network means that it takes longer for power to be restored and that it is therefore better to invest now rather than wait until poles fail. Customers made it clear that they expect safety and network reliability performance to be maintained.

In considering the feedback provided by the AER, our independent expert advice and our customers' strong support for investment in the ageing network, we are seeking a reconsideration by the AER of major elements of our replacement capex forecast. This is further outlined in the sections below.

5.5.2 What we accept

We accept the AER's Draft Decision on:

- the following elements of replacement capex where the AER has accepted our forecast expenditure:
  - underground cable replacements
  - tower replacement program
  - service line replacements
  - return to service program, and
  - relay replacements.
- the following elements of replacement capex where the AER has provided a substitute forecast:
  - distribution transformer replacements – both stand-alone and a portion of our consequential replacements (the AER refers to these as "opportunistic" replacements)
  - distribution switches replacements – both stand-alone and a portion of our consequential replacements
  - substation switchgear and transformer replacements
  - grid communications – we accept the AER's Draft Decision on 14 of 29 projects, and
  - operational technology – we accept the AER's Draft Decision on two of five projects.

5.5.3 What we have modified

Incorporating the AER's feedback, we have modified a small number of our business cases to improve our CBA modelling and updated them with the latest available data to justify these areas:

- **Defect-driven pole replacements** – we have an obligation under the *Electrical Safety Code of Practice* to limit the number of unassisted pole failures to below one in 10,000 poles across our population. Our current level of defect-driven pole replacements is to ensure we meet this obligation. Ergon Energy Network proposes a reduced overall expenditure for our defect-driven pole replacements. While our volume of pole replacements has remained the same, we have reduced the level of consequential "opportunistic" replacements based on the AER's feedback, though not to the level of the AER's substitute forecast. We have submitted a revised business case incorporating these changes and some improvements in our modelling of the CBA, which demonstrates clearer customer benefits of our proposed program (refer to Attachment 5.5.02)

- **Pole-top structure replacements** – the AER's substitute forecast covers only the defect-driven pole top structure replacements and does not account for proactive replacement. We have not accepted the AER's alternative forecast and have revised the business case to clearly demonstrate the justification for the proactive pole top structure replacements. Ergon Energy Network proposes a minor reduction in our expenditure in this program when compared to our Regulatory Proposal (refer to Attachment 5.5.03)
- **Conductor replacements** – the AER accepted our proposed volume of conductor replacements in its Draft Decision but reduced some of what we called "consequential" replacements of pole-top structures, service cables and poles that formed part of this investment. While we referred to these as "consequential" replacements, the AER rightly pointed out that these would be better classified as "enabling" replacements if they are required to be replaced due to the size and strength requirements of a new conductor type. We have incorporated the AER's feedback and reduced the volume of "opportunistic" replacements and are providing further justification for the "enabling" replacement components (e.g. pole, pole top structures and services type assets) when compared with our Regulatory Proposal. However, these have not reduced to the level of the AER's substitute forecast. We have explained the need for the "enabling" replacements as part of our business case for conductor replacements (refer to Attachment 5.5.04)
- **Grid communications -** we have incorporated the AER's feedback and modified our proposed investments in six of our grid communications investments and provided further options analysis and justification for the remaining nine projects in this portfolio (refer to Attachments 5.5.09 to 5.5.23), and
- **Operational technology** – we have provided further options analysis and justification for three of our operational technology investments, namely Storage Backup Replacement, Zetron Replacement and General Infrastructure Replacement (refer to Attachments 5.5.05 to 5.5.08).

5.6 Augmentation

Augmentation capex is the investment associated with building new network or upgrading the capacity of the existing network to cater for growth in network demand.

The AER has not accepted our proposed forecast of $513.2 million[54] over five years and provided a substitute forecast of $429.2 million.[55] These values exclude clearance capex as the AER moved this expenditure to replacement capex. As previously outlined, we consider this type of expenditure is more appropriately categorised as augmentation and intend to continue to report clearance expenditure as augmentation. For these reasons, clearance capex has been included in our response to the AER's Draft Decision on forecast augmentation, which is summarised in Table 15.

[54] This amount represents the net outcome of the revised augmentation capex forecast submitted to the AER on 28 June 2024 ($763.4 million) plus the AER's re-categorisation of $181.1 million to replacement capex, $53.1 million to resilience capex and $16.1 million to cyber security capex.

[55] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Attachment 5 – Capital expenditure*, September 2024, p. 19.

For improved clarity we have listed the clearance capex separately to enable a meaningful comparison with the AER's Draft Decision.

Table 15: Summary of our response to AER's Draft Decision on augmentation capex

$m, real 2024-25	Regulatory Proposal	Draft Decision[1]	Difference to Regulatory Proposal	Our Response	Revised Regulatory Proposal[2]	Difference to Regulatory Proposal
Sub-transmission Growth	188.6	188.3	-0.3	Accept	188.5	-0.1
Reliability	14.0	14.0	0.0	Accept	14.1	0.1
Distribution Growth	216.6	166.0	-50.6	Modify	210.8	-5.8
• Distribution Growth (24 projects)	166.0	166.0	0.0	Accept	166.1	0.1
• Maintain Reliability	50.6	0.0	-50.6	Modify	44.6	-5.9
SCADA, Protections and Communications	94.0	60.5	-33.5	Modify	75.8	-18.2
• Grid Communications	24.6	15.8	-8.8	Modify	19.4	-5.2
• DC System Duplication and Bus Overcurrent Protection	13.6	5.5	-8.1	Accept	5.5	-8.1
• Backup Reach Protection Improvement Program	11.1	0.0	-11.1	Justify	11.1	-0.0
• Operational Technology	3.4	1.5	-1.9	Modify	1.5	-1.9
• Protection	2.3	0.3	-2.0	Accept	0.9	-1.4
• Intelligent Grid and Grid Control	39.0	37.4	-1.6	Accept	37.4	-1.6
Augmentation Sub-total[3]	**513.2**	**428.8**	**-84.4**	**Modify**	**489.2**	**-24.0**
Clearance to Ground & Structure Program	181.1	105.7	-75.4	Modify	164.8	-16.3
Augmentation Total[4]	**694.3**	**534.5**	**-159.8**	**Modify**	**654.0**	**40.3**

Notes:
1. Values sourced from the AER Capex Model (Ergon Energy distribution determination 2025-30). Minor discrepancies exist between the summation of the disaggregated information in the AER's Capex Model and the aggregated amounts published in the AER's Draft Decision.
2. Minor differences between Draft Decision and Revised Regulatory Proposal values are due to inflation adjustment.
3. Augmentation sub-total excludes clearance capex. Sub-totals may not add due to rounding.
4. Augmentation total includes clearance capex. Totals may not add due to rounding.

We have analysed the feedback provided in the AER's Draft Decision and accepted its alternative forecast in a range of areas, including:

- **Sub-transmission growth** – the AER accepted the set of sub-transmission projects. We are not seeking any changes to those projects in our Revised Regulatory Proposal
- **Worst performing feeder program** – the AER accepted our proposal for this program. We are not seeking any changes in our Revised Regulatory Proposal
- **Distribution growth –** the AER accepted 24 of our 25 proposed investments in the distribution growth category. We are not seeking any changes to these projects in our Revised Regulatory Proposal, and
- **Grid communications, protection and control** – the AER accepted 34 of the projects in the grid technology category and made some adjustment to 20 further projects in their alternative forecast. We accept the AER's Draft Decision for these projects.

As a result of the AER's feedback, we have modified a small number of business cases to improve our CBA modelling and include the latest available data to justify these areas:

- **Distribution Feeder Augmentation Unplanned Reliability** - the AER's alternative forecast provided no allocation for the maintain reliability program because our overall reliability is stable. Considering this feedback, we have refocused this program on those communities that have particularly poor reliability performance (refer to Attachment 5.6.02)
- **Backup Reach Protection Improvement Program** – the AER's alternative forecast provided no allocation for our proposal to improve our backup protection reach based on a difference in interpretation of clause S5.1.9(f) of the NER. We have updated the business case for this proposal to better articulate the requirement to have duplicate protection on our assets to prevent plant damage following a downstream fault in line with the NER (refer to Attachment 5.6.03)
- **Grid Communications** – we have incorporated the AER's feedback and included lower expenditure forecasts for investments targeting an improvement in communications reliability for two projects. Attachments 5.6.04 and 5.6.05 outline our modifications and justification for these projects, and
- **Operational Technology** – we have incorporated the AER's feedback and included a lower expenditure forecast for our investment in the Zetron system (refer to Attachment 5.5.08).

5.6.1 Clearance to ground and clearance to structure program

In its Draft Decision, the AER re-categorised our clearance to ground and clearance to structure program as replacement capex. As already discussed, for the 2020-25 regulatory control period we began reporting this program as augmentation expenditure, as this category better reflects the underlying requirement for investment. For the 2025-30 regulatory control period we will continue to report this program as augmentation and therefore have included our forecast clearance expenditure in this category. This approach also maintains consistency between our Regulatory Proposal and Revised Regulatory Proposal, which we consider is important for our customers and stakeholders.

In its Draft Decision, the AER accepted our forecast volumes of clearance issues required across the network but had concerns with our unit rates for rectifications. We have updated the unit rates and have segmented them between major and minor rectification works. This allows for a higher unit rate to apply to more complex works and a lower unit rate to apply to more simple minor works (such as re-tensioning). This has resulted in a reduction in our clearance type category expenditure (refer to Attachment 5.6.01).

5.7 Resilience

The AER has assessed our resilience capex separately for its Draft Decision. The resilience investment we proposed was included in our augmentation capex forecast and has been re-categorised into a stand-alone resilience capex category by the AER.

The AER has provided a substitute forecast of $26.8 million over five years. It recognised the merits of the bushfire and flood program and the mobile substation proposal but did not accept the mobile generation proposal. The AER also did not accept the SAPS investment proposal due to the current regulatory environment.

Ergon Energy Network accepts most of the AER's substitute forecast for this expenditure category. However, we are modifying our new mobile generation proposal (refer to Table 16). Should the regulatory environment change, we will consider future options regarding SAPS.

Table 16: Summary of our response to AER's Draft Decision on Resilience

$m, real 2024-25	Regulatory Proposal	Draft Decision	Difference to Regulatory Proposal	Our Response	Revised Regulatory Proposal	Difference to Regulatory Proposal
New Mobile Generation	19.3	1.9	-17.4	Modify	9.7	-9.6
Bushfire and Flood Business Case	16.1	16.1	-	Accept	16.1	-
New Mobile Substation	8.8	8.8	-	Accept	8.8	-
Standalone Power System	8.9	0.0	-8.9	Accept	-	-8.9
Resilience Total	**53.1**	**26.8**	**-26.3**	**Modify**	**34.6**	**-18.5**

The AER's Draft Decision was that additional mobile generation was not required to meet our minimum service standards and reduced our proposed capex down to pre-2020 levels.[56] In line with feedback from the AER and considering the level of replacement expenditure included in this Revised Regulatory Proposal, we have reconsidered our requirements and propose a reduction to this investment of 50 per cent when compared to our Regulatory Proposal. The revised business case improves articulation of the need for further generation and how this investment will improve customer outcomes (refer to Attachment 5.7.01).

[56] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Attachment 5 – Capital expenditure*, September 2024, p. 82.

5.8 Distributed energy resources

Distributed energy resources is a new category of expenditure for the 2025-30 regulatory control period. This category of expenditure relates to augmentation of the network to resolve constraints associated with incorporating distributed energy resources that export energy into the distribution network. This could include exports from rooftop solar, battery storage or electric vehicles with vehicle-to-grid capability.

The AER accepted our distributed energy resources-related capex proposal of $63.0 million over five years. The AER found that our strategy was generally sound and measured and was supportive of our approach to prioritising dynamic connection investments over increasing hosting capacity.[57]

We accept the AER's Draft Decision for distributed energy resources-related capex of $63.0 million for the 2025-30 regulatory control period.

5.9 Connections

Net connection expenditure is the investment required to connect new residential and small business customers to our distribution network. Population growth drives the volume of new home and business customer connections and, as outlined in our Regulatory Proposal, regional Queensland's population growth has been strong since the Covid-19 pandemic and is forecast to continue to grow during 2025-30.

The AER accepted our net connection capex proposal of $321.2 million over five years. The AER was satisfied with our proposal after having regard to average unit rates, trend analysis and Queensland Government data (i.e. population growth information).[58]

We accept the AER's Draft Decision for net connection capex. After adjusting for updated inflation inputs, our connections-related capex forecast is now $321.3 million for the 2025-30 regulatory control period.

5.10 Cyber security

Ergon Energy Network and other critical infrastructure service providers face growing cyber threats due to more connectivity, increased adoption of big data and cyber-physical assets, and greater digitalisation and automation. Investing in cyber security helps to protect our network and data from cyber security threats, such as ransomware or malicious critical infrastructure attacks.

The AER has assessed our cyber security capex as a stand-alone category for its Draft Decision.

In our Regulatory Proposal, the funding proposal for cyber security was contained within one business case, but the funding was split into three categories, i.e. replacement ($7.9 million), augmentation ($16.1 million) and non-network ICT ($29.4 million).

The AER accepted our total cyber security forecast of $53.4 million over five years as it found that the information provided adequately supported the proposal and that we had a good understanding of our compliance obligations.[59]

We accept the AER's Draft Decision for cyber security capex. After adjusting for updated inflation inputs, our cyber security capex forecast is now $53.3 million for the 2025-30 regulatory control period.

---

[57] Ibid, p. 18.
[58] Ibid, p. 17.
[59] Ibid, p. 18.

5.11 Information, communications and technology

Our non-network ICT investments focus on ensuring that our systems are maintained for sustainability, compliance and operational safety and security, while keeping pace with the expected industry transition to a more connected, digitalised environment.

The AER has provided a substitute forecast of $208.7 million over five years for non-network ICT capex (excluding cyber security). We note the AER's feedback on our business cases and the AER's conclusion that the "maintain" base case option is prudent and efficient.[60]

We appreciate the AER's openness to engaging with us and have met with the AER to discuss their feedback and some of the challenges all DNSP's face in preparing digital business cases in a rapidly changing technological environment.

We remain of the view that our proposed expenditure is necessary to keep pace with the growing digitalisation and ever-changing customer expectations of the electricity industry. However, given the complexity of dependencies between investments enabling benefits and business units realising benefits, as well as the business priority in responding to other aspects of the Draft Decision, we will accept the AER's Draft Decision for non-network ICT capex.

After adjusting for updated inflation inputs, our non-network ICT capex forecast is now $208.4 million for the 2025-30 regulatory control period.

5.12 Other non-network

To meet customers' expectations for a safe and reliable electricity supply, we must equip our workforce with the right buildings, vehicles, tools and equipment so that they can efficiently deliver electricity to customers. To do this we invest in three categories of support costs: property (including capitalised leases), fleet, and tools and equipment.

The AER's Draft Decision for these support costs was to:

- provide a substitute forecast for our non-network property expenditure of $170.7 million over five years (a 2.3 per cent reduction from our Regulatory Proposal forecast)[61]
- adjust our fleet forecast of $243.0 million to $210.1 million over five years based on accepting the base case for the elevating work platform (EWP) and crane borer business cases, along with the removal of the full-time equivalent (FTE) uplift based on adjustments made to the network capex forecasts,[62] and
- accept our tools and equipment forecast of $31.7 million over five years.[63]

We accept the AER's Draft Decision on our property (including capitalised leases), and tools and equipment forecasts.

For our fleet forecast, we accept the AER's Draft Decision to remove the expenditure forecast related to the FTE uplift. However, we are requesting additional capex of $12.2 million above the Draft Decision to reflect our preferred replacement strategy for both EWPs and crane borers (refer to Table 17). The capex forecast which has been included for this strategy is equivalent to our Regulatory Proposal.

[60] Ibid, p. 19.
[61] Ibid, p. 20.
[62] Ibid, p. 20.
[63] Ibid, p. 18.

Table 17: Summary of our response to AER's Draft Decision on other non-network capex

$m, real 2024-25	Regulatory Proposal	Draft Decision[1]	Difference to Regulatory Proposal	Our Response	Revised Regulatory Proposal[2]	Difference to Regulatory Proposal
Property (including capitalised leases)	174.7	170.7	-4.0	Accept	170.2	-4.5
Fleet	243.0	210.1	-32.9	Modify	222.3	-20.7
Tools and equipment	31.7	31.7	0.0	Accept	31.6	-0.1
Other Non-network Total[3]	**449.4**	**412.5**	**-36.9**	**Modify**	**424.1**	**-25.3**

Notes:
1. Values sourced from the AER Capex Model (Ergon Energy distribution determination 2025-30). Minor discrepancies are due to differences between the Capex Model and the AER's published Draft Decision.
2. Minor differences between Draft Decision and Revised Regulatory Proposal values are due to inflation adjustment.
3. Totals may not add due to rounding.

Table 18 summarises how we have responded to feedback from the AER and customers.

Table 18: How we have responded to AER's Draft Decision on other non-network capex

Issue in Draft Decision	Our response	More information
Fleet Base case approved for EWP and crane borers due to lack of evidence to support the downtime benefits used in the NPV calculation.	We acknowledge the lack of detailed evidence provided to support our downtime benefit calculation. For the EWP assets, the datasets which were used to calculate the number of days downtime and the cost per day have now been included as supporting information in Appendix 4 of the business case. For the crane borer assets, this business case did not use the downtime benefit for aged truck assets. We consider that the preferred option is the most prudent and efficient option, as it has the lowest NPV and is justified solely on it having the most efficient long-term operating and capital costs.	Attachments 5.11.01 (EWP) and 5.11.02 (Crane Borer).
Fleet Removal of FTE uplift based on wider reductions to the total network capex forecast.	We accept the AER's Draft Decision and have removed the forecast related to the FTE uplift over the 2025-30 regulatory control period.	N/A
Property Base case approved for Rocklea Training Facility due to revenue benefits being included from ACS.	After reviewing the AER's feedback, we acknowledge that we have different views around how the benefits of training revenue are included. However, given that we have already included our position in a response to an information request and have no further quantification, we will accept the AER's Draft Decision for non-network property.	N/A

5.13 Capitalised overheads

Overheads are business support costs that we incur in delivering network services to customers (e.g. costs related to finance, human resources or indirect costs incurred to operate and maintain vehicles or property). We capitalise some of our overheads (i.e. include them in capex) in accordance with our Cost Allocation Methodology (CAM) and capitalisation policies, as well as accounting standards requirements.

The AER's Draft Decision for these support costs was to provide a substitute estimate of $874.4 million over five years based on its standard methodology and apply our proposed annual 1.0 per cent efficiency adjustment. The AER's methodology uses the available actual capex and overheads from the current regulatory control period, which is typically three years for a draft decision and four years for a final decision.[64] In our Regulatory Proposal, we estimated our capitalised overheads using a bottom-up build based on the most recent year of actual capex and overheads (which was 2022-23).

We accept the use of the AER's methodology and have recalculated our capitalised overheads using the most recent actual capex and overheads inputs. In line with our opex, we have applied an efficiency adjustment of 1.0 per cent to these costs. Our capitalised overheads forecast for the 2025-30 regulatory control period is $1,009.7 million.

5.14 Supporting documentation

The following documents support this chapter:

Document Name	Reference	File name
Our Response to the AER's Draft Decision		
Ergon SCS Capex Model	5.2.01	Ergon - 5.2.01 - SCS Capex model - November 2024 - public
Ergon Additional Information	5.2.02	Ergon - 5.2.02 - Additional Information - November 2024 - public Ergon - 5.2.02A - Capex Expenditure Summary CA RIN 2.1.1 - November 2024 - public Ergon - 5.2.02B - Repex Expenditure CA RIN 2.2 - November 2024 - public Ergon - 5.2.02C - Repex Asset Failure Data Conductor - November 2024 - public Ergon - 5.2.02D - Repex Asset Failure Data Unassisted Pole - November 2024 - public Ergon - 5.2.02E - Repex Asset Failure Data Unassisted Pole Top - November 2024 - public Ergon - 5.2.02F - Repex Asset Failure Data Service Line - November 2024 - public Ergon - 5.2.02G - Repex Asset Failure Data Transformer - November 2024 - public Ergon - 5.2.02H - Repex Asset Failure Data Switchgear - November 2024 - public Ergon - 5.2.02I - Repex Asset Age Profile - November 2024 - public Ergon - 5.2.02J - Augex Quality of Service Data - November 2024 - public

[64] Ibid, p. 91-92.

Document Name	Reference	File name
		Ergon - 5.2.02K - Augex Reliability and Service Performance - November 2024 - public Ergon - 5.2.02L - Repex Poles Root Cause Analysis - November 2024 - public Ergon - 5.2.02M - Repex Bottom Up Reconciliation Volume - November 2024 - public Ergon - 5.2.02N - Repex Poles Failure Mismatch - November 2024 - public Ergon - 5.2.02O - 2018-2025 Network Expenditure Program List - November 2024 - public
Response to Reset RIN 4.4.4 and 4.4.5 Capex Transparency	5.2.03	Ergon - 5.2.03 - Response to Reset RIN 4.4.4 and 4.4.5 Capex Transparency - November 2024 - public
Our Response to the EMCa Review		
Aurecon - Independent response to EMCa's "Review of Aspects of Proposed Expenditure"	5.3.01	Ergon - 5.3.01 - Aurecon - Independent response to EMCa's Report - November 2024 - public
TSA Riley - Review of Aspects of Ergon Energy Replacement Expenditure	5.3.02	Ergon - 5.3.02 - TSA Riley - Review of Ergon Replacement Expenditure - October 2024 - public
Frontier Economics - Counterfactual for Repex Business Cases	5.3.03	Ergon - 5.3.03 - Frontier Economics - Counterfactual for Repex Business Cases - November 2024 - public
Response to EMCa Cost Benefit Analysis Concerns	5.3.04	Ergon - 5.3.04A - Response to EMCa Cost Benefit Analysis Concerns - November 2024 - public Ergon - 5.3.04 B - NPV Model - Supporting Example - November 2024 - public
Ex-post review		
Aurecon - Validity of Ergon Energy versus Peer Comparisons for Pole Replacements	5.4.01	Ergon - 5.4.01 - Aurecon - Validity of Ergon Energy versus Peer Comparisons for Pole Replacements - October 2024 - public
Replacement		
Repex Ex-Post and Ex-Ante Narrative document and supporting information	5.5.01	Ergon - 5.5.01A - Repex Ex-post and Ex-ante Narrative - November 2024 - public Ergon - 5.5.01B - Cost Benefit Analysis Enhancement Presentation - October 2024 - public Ergon - 5.5.01C - RIN Repex Forecast Model Report - October 2024 - confidential Ergon - 5.5.01D - RIN Repex Forecast 2025-30 Revised Submission - October 2024 - public Ergon - 5.5.01E – Model Validation – Reliability Cost Estimation - November 2024 - public
Business Case – Pole Replacement	5.5.02	Ergon - 5.5.02A - Business Case - Pole Replacement (Ex-post & Ex-ante) - November 2024 - public Ergon - 5.5.02B - Cost Benefit Analysis Pole Examples - November 2024 - public Ergon - 5.5.02C - Cost Benefit Analysis NPV Poles Model - November 2024 - confidential Ergon - 5.5.02D - Defect Bundling Scenario - October 2024 - public
Business Case and NPV Model – Pole Top Replacement	5.5.03	Ergon - 5.5.03A - Business Case - Pole Top Structure Replacement (Ex-ante) - November 2024 - public

Document Name	Reference	File name
		Ergon - 5.5.03B - Cost Benefit Pole Top Structure Examples - October 2024 - public Ergon - 5.5.03C - NPV Model - Pole Top Structure Replacement (Ex-ante) - November 2024 - confidential Ergon - 5.5.03D - C3 Defect Information - October 2024 - public
Business Case – OH Conductor Enabling Consequential (ex-post and ex-ante)	5.5.04	Ergon - 5.5.04A - Business Case - OH Conductor - Enabling Consequential (Ex-ante) - November 2024 - public Ergon - 5.5.04B - Distribution Lines Refurbishment Guideline - REPEX - 3034999 - November 2024 - public
NPV Model – OTE Expenditure (Augex and Repex)	5.5.05	Ergon - 5.5.05 - NPV Model - OTE Expenditure (Augex & Repex) - November 2024 - public
Business Case – OTE Storage Backup Replacement	5.5.06	Ergon - 5.5.06 - Business Case - OTE Storage Backup Replacement - November 2024 - public
Business Case – OTE Infrastructure Replacements	5.5.07	Ergon - 5.5.07 - Business Case - OTE Infrastructure Replacements - November 2024 - public
Business Case – OTE Zetron Continuous Improvement & Replacement	5.5.08	Ergon - 5.5.08 -Business Case - OTE Zetron Continuous Imp & Replacement - November 2024 - public
Grid Comms Revised Investment Program and NPV Model	5.5.09	Ergon - 5.5.09A - GRID COMMS - Revised Investment Program - November 2024 - public Ergon - 5.5.09B - GRID COMMS - NPV Model - November 2024 - public
Business Case – Grid Comms – AC System replacement	5.5.10	Ergon - 5.5.10 - Business Case - GRID COMMS - AC Systems Replacement - November 2024 - public
Business Case – Grid Comms – Microwave Radio Edge Capricornia and Mackay Replacements	5.5.11	Ergon - 5.5.11 - Business Case - GRID COMMS - Microwave Radio Edge Capricornia and Mackay Replacements - November 2024 - public Ergon - 5.5.11 - Business Case - GRID COMMS - Microwave Radio Edge Capricornia and Mackay Replacements - November 2024 - confidential
Business Case – Grid Comms – SDH Replacement Edge	5.5.12	Ergon - 5.5.12A - Business Case - GRID COMMS - SDH Replacement Edge - November 2024 – public Ergon - 5.5.12A - Business Case - GRID COMMS - SDH Replacement Edge - November 2024 - confidential Ergon - 5.5.12B - Business Case - GRID COMMS - SDH Replacement Core - November 2024 - public Ergon - 5.5.12B - Business Case - GRID COMMS - SDH Replacement Core - November 2024 - confidential
Business Case – Grid Comms – Edge Router Replacements	5.5.13	Ergon - 5.5.13 - Business Case - GRID COMMS - Edge Router Replacements - November 2024 – public Ergon - 5.5.13 - Business Case - GRID COMMS - Edge Router Replacements - November 2024 - confidential
Business Case – Grid Comms – Microwave Radio Edge South West and Wide Bay	5.5.14	Ergon - 5.5.14 - Business Case - GRID COMMS - Microwave Radio Edge South West and Wide Bay - November 2024 – public Ergon - 5.5.14 - Business Case - GRID COMMS - Microwave Radio Edge South West and Wide Bay - November 2024 - confidential

Document Name	Reference	File name
Business Case – Grid Comms – Microwave Radio Edge North Queensland and Far North Replacements	5.5.15	Ergon - 5.5.15 - Business Case - GRID COMMS Microwave Radio Edge Nth QLD and Far North Replacements - November 2024 - public Ergon - 5.5.15 - Business Case - GRID COMMS Microwave Radio Edge Nth QLD and Far North Replacements - November 2024 - confidential
Business Case – Grid Comms – Operational Voice Replacements	5.5.16	Ergon - 5.5.16 - Business Case - GRID COMMS - Operational Voice Replacements - November 2024 - public
Business Case – Grid Comms – Data Centre Ethernet Replacements	5.5.17	Ergon - 5.5.17 - Business Case - GRID COMMS - Data Centre Ethernet Replacements - November 2024 – public Ergon - 5.5.17 - Business Case - GRID COMMS - Data Centre Ethernet Replacements - November 2024 - confidential
Business Case – Grid Comms – P25 Replacement Edge	5.5.18	Ergon - 5.5.18 - Business Case - GRID COMMS - P25 Replacement Edge - November 2024 - public
Business Case – Grid Comms – Microwave Radio Core Replacements	5.5.19	Ergon - 5.5.19 - Business Case - GRID COMMS - Microwave Radio Core Replacements - November 2024 - public Ergon - 5.5.19 - Business Case - GRID COMMS - Microwave Radio Core Replacements - November 2024 - confidential
Business Case – Grid Comms – Operational Support Systems Replacements	5.5.20	Ergon - 5.5.20 - Business Case - GRID COMMS - Operational Support Systems Replacements - November 2024 - public Ergon - 5.5.20 - Business Case - GRID COMMS - Operational Support Systems Replacements - November 2024 - confidential
Business Case – Grid Comms – DC Systems Replacements	5.5.21	Ergon - 5.5.21 - Business Case - GRID COMMS - DC Systems Replacements - November 2024 - public
Business Case – Grid Comms – Core IP MPLS Ethernet Replacements	5.5.22	Ergon - 5.5.22 - Business Case - GRID COMMS - Core IP MPLS Ethernet Replacements - November 2024 – public Ergon - 5.5.22 - Business Case - GRID COMMS - Core IP MPLS Ethernet Replacements - November 2024 - confidential
Business Case – Grid Comms – Fringe Network Replacements	5.5.23	Ergon - 5.5.23 - Business Case - GRID COMMS - Fringe Network Replacements - November 2024 - public
Reset RIN Repex 2.2 – Forecast Data	5.5.24	Ergon - 5.5.24 - Reset RIN Repex 2.2 - Forecast Data - November 2024 - public
Augmentation		
Business Case – Clearance to Ground and Structure	5.6.01	Ergon - 5.6.01 - Business Case - Clearance to Ground and Structure - November 2024 - public
Business Case and NPV Model – Distribution Growth Unplanned Reliability	5.6.02	Ergon - 5.6.02A - Business Case - Distribution Growth Unplanned Reliability - November 2024 - public Ergon - 5.6.02B - NPV Model - Distribution Growth Unplanned Reliability - November 2024 - public
Business Case – Backup Protection	5.6.03	Ergon - 5.6.03 - Business Case - Backup Protection - November 2024 - public

Document Name	Reference	File name
Business Case – Grid Comms – Reliability Core MPLS and Fibre	5.604	Ergon - 5.6.04 - Business Case - GRID COMMS - Reliability Core MPLS and Fibre - November 2024 - public Ergon - 5.6.04 - Business Case - GRID COMMS - Reliability Core MPLS and Fibre - November 2024 - confidential
Business Case – Grid Comms – Reliability Edge Fringenet and Backhaul	5.605	Ergon - 5.6.05 - Business Case - GRID COMMS - Reliability Edge Fringenet and Backhaul - November 2024 - public Ergon - 5.6.05 - Business Case - GRID COMMS - Reliability Edge Fringenet and Backhaul - November 2024 - confidential
Resilience		
Business Case and NPV Model – Mobile Generation	5.7.01	Ergon - 5.7.01A - Business Case - Mobile Generation - November 2024 - public Ergon - 5.7.01B - NPV Model - Mobile Generation - November 2024 - public
Other non-network		
Business case and NPV model – EWP Replacement	5.12.01	Ergon - 5.12.01A - Business Case Non-Network Fleet - EWP Replacement - November 2024 - public Ergon - 5.12.01A - Business Case Non-Network Fleet - EWP Replacement - November 2024 - confidential Ergon - 5.12.01B - NPV Model Non-Network Fleet - EWP Replacement - November 2024 – confidential
Business case and NPV model – Crane Borer Replacement	5.12.02	Ergon - 5.12.02A - Business Case Non-Network Fleet - Crane Borer Replacement - November 2024 - public Ergon - 5.12.02A - Business Case Non-Network Fleet - Crane Borer Replacement - November 2024 - confidential Ergon - 5.12.02B - NPV Model Non-Network Fleet - Crane Borer Replacement - November 2024 - confidential
Non-network Fleet Forecast Replacement Model	5.12.03	Ergon - 5.12.03 - Non-Network Fleet forecast replacement model - November 2024 - confidential
Capitalised overheads		
Capitalised Corporate Overhead Calculations Model	5.13.01	Ergon - 5.13.01 - Capitalised Corporate Overhead Calculations - November 2024 - public

6.
Operating Expenditure

Key messages:

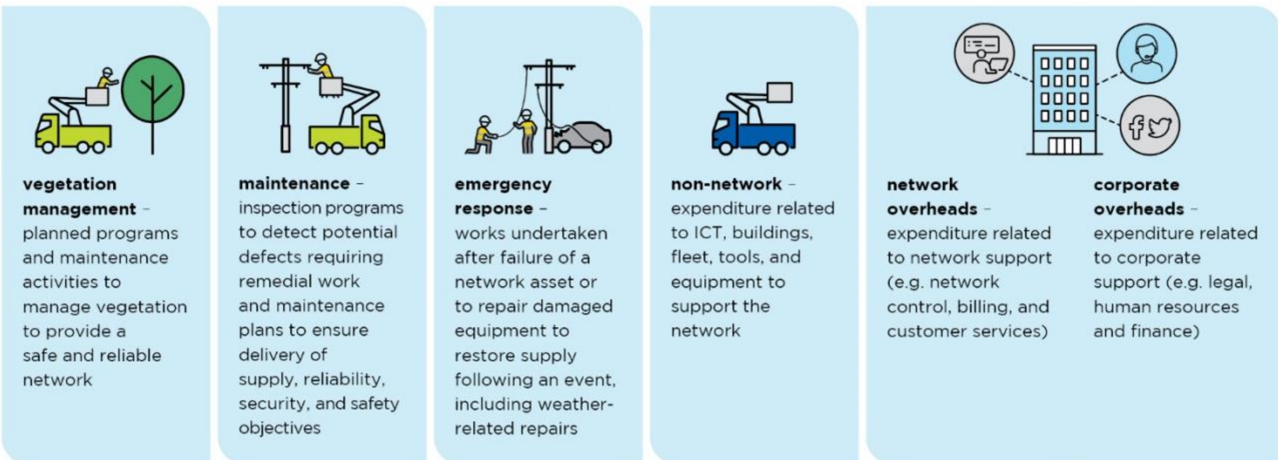
- Our customers expect Ergon Energy Network to continue to affordably deliver a safe, secure and reliable network.
- In the Regulatory Proposal, we forecast opex for the 2025-30 regulatory control period of $2,379.1 million (including debt raising costs). The AER accepted this forecast.
- Our Regulatory Proposal was based on a forecast 2023-24 base year. Our base year opex has been updated to reflect actual data for 2023-24.
- We have made an efficiency adjustment to the base year, applied a 1.0 per cent annual productivity factor to apply over the 2025-30 regulatory control period and included only one step change.
- Our forecast opex to meet customers' expectations for the 2025-30 regulatory control period is now $2,562.9 million, a 7.7 per cent increase on our Regulatory Proposal and the AER's Draft Decision.
- Our opex forecast is one of the building blocks that form part of our revenue requirement.

6.1 Overview

We incur costs to operate and maintain our network to meet the everyday performance and service needs of our customers and communities, including meeting expectations around keeping our network safe, reliable and secure, while ensuring that we do so as efficiently as possible. Customers also rely on us to restore power supply as quickly as possible following severe weather events and natural disasters.

Our opex is a key building block of our annual revenue requirement, and costs are recovered on an annual basis. This expenditure is broken down into the high-level categories set out in Figure 7.

Figure 7: Opex categories



6.2 Our response to the AER's Draft Decision

In our Regulatory Proposal we forecast opex of $2,379.1 million (inclusive of debt raising costs) for the 2025-30 regulatory control period.

In its Draft Decision, the AER calculated an alternative estimate of $2,401.8 million (1.0 per cent higher than our Regulatory Proposal). The AER therefore accepted Ergon Energy Network's proposed forecast but noted that we would provide actual opex for 2023-24 for consideration in the Final Decision.[65]

Our Regulatory Proposal was based on a forecast 2023-24 base year. We have updated our data to reflect actual 2023-24 costs and the most recent information for other model inputs. Our revised forecast opex is $2,562.9 million over the 2025-30 regulatory control period. This represents an increase of 7.7 per cent relative to our Regulatory Proposal and the AER's Draft Decision. We consider this level of opex is required to carry out the activities outlined in Figure 7 to achieve the opex objectives listed in clause 6.5.6 of the NER.

Our response to the AER's Draft Decision on our forecast opex is summarised in Table 19.

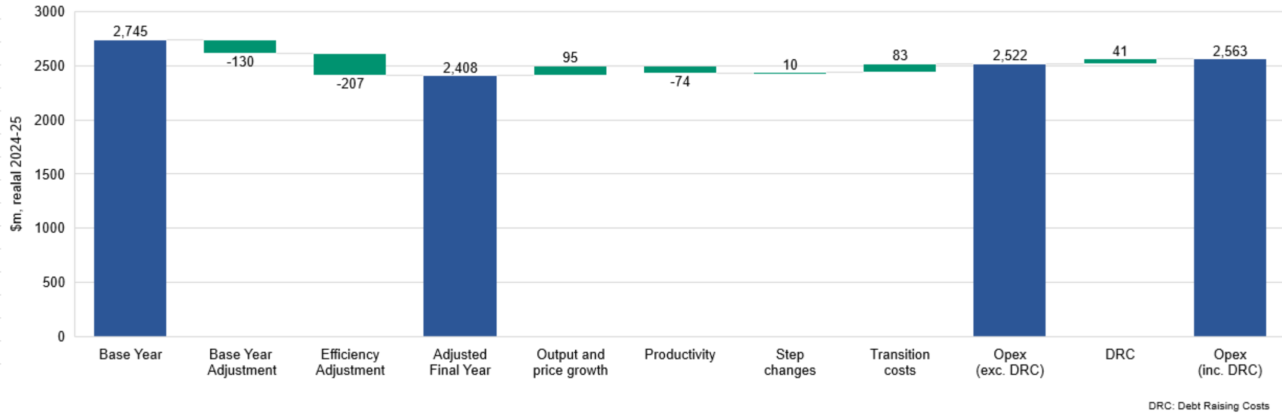
Table 19: Summary of our response to AER's Draft Decision on opex

$m, real 2024-25	Regulatory Proposal	AER alternative estimate[1]	Difference to Regulatory Proposal	Summary of our response	Revised Regulatory Proposal	Difference to Regulatory Proposal
Base opex	2,481.0	2,476.3	-4.7	Modify	2,744.8	263.8
Efficiency adjustments	-55.3	-45.2	-10.1	Modify	-206.5	151.2
Transition costs	0.0	18.3	18.3	Modify	83.1	83.1
Base year adjustments	-68.0	-67.9	0.1	Modify	-59.4	8.6
2023-24 to 2024-25 increment	-30.7	-30.5	0.2	Modify	-30.5	0.2
Remove debt raising costs	-30.4	-30.3	0.1	Modify	-40.2	-9.8
Trend: Price growth	51.8	46.8	-5.0	Modify	46.2	-5.6
Trend: Output growth	49.4	29.0	-20.4	Modify	48.4	-1.0
Trend: Productivity growth	-68.7	-34.6	34.1	Modify	-74.1	-5.4
Step changes	6.8	0.0	-6.8	Modify	10.0	3.2
Total opex excl DRC[2]	**2,336.0**	**2,361.9**	**26.0**	**Modify**	**2,521.8**	**185.9**
Debt raising costs	43.1	39.9	-3.2	Modify	41.1	-2.0
Total[2]	**2,379.1**	**2401.8**	**22.8**	**Modify**	**2,562.9**	**183.9**

Notes:
1. As the AER'S alternative estimate was higher than Ergon Energy Network's Regulatory Proposal, the AER accepted the proposal of $2,379.1 million.
2. Totals may not add due to rounding.

[65] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Overview,* September 2024, pp. 22-23.

Figure 8: Components of Forecast Opex 2025-30 ($m, real 2024-25)



Whilst approving the opex included in our Regulatory Proposal, the AER included feedback on the approach for some components or requested further information be provided in the Revised Regulatory Proposal. Table 20 sets out how we have responded to the AER's feedback in the Draft Decision and where to find more information.

Table 20: How we have responded to AER's Draft Decision on opex

Issue in Draft Decision	Our response	More information
Engagement Lack of genuine engagement on opex forecasts.	We acknowledge the limited scope for engagement on opex forecasts. This is, in part, due to the lack of ability to influence outcomes as a result of using a standardised base-step-trend model. We discussed our approach to the acquisition of smart meter data with our RRG, who provided feedback that investment should be based on the highest net benefit option. We also discussed our proposed higher 1.0 per cent productivity factor with the RRG in our engagement on the Draft Plans, and engagement with the Customer and Community Council and VOC Panels.	N/A
Productivity Encouraged to consider how we will achieve productivity savings and provide this detail in revised proposal.	The reductions in opex due to the efficiency adjustment and the productivity factor will be a significant challenge for our business as the costs of managing our network continue to rise. However, we are committed to continuing to deliver a safe, secure and reliable network in the 2025-30 regulatory control period.	Further detail on how Ergon Energy Network is proposing to achieve efficiencies in the 2025-30 regulatory control period is included in Attachment 6.05.
Base year Consider if 2023-24 is an appropriate choice of base year.	The base year 2023-24 has been selected as it represents the most recent year for which actual audited data is available.	Section 6.4.1.

Issue in Draft Decision	Our response	More information
Operating environment factors Seeking network overheads data separated into amounts expensed and capitalised based on the current CAM.	We engaged with the AER on the request for this information in October 2024. The AER was provided with the network overheads data required for the purposes of sensitivity testing.	N/A
Step changes Not satisfied that Ergon Energy Network has demonstrated that the costs associated with purchasing near real-time meter data are prudent and efficient. Did not provide supporting information to demonstrate key benefit assumptions.	We have updated the business case and CBA to incorporate the AER's and EMCa's feedback, the Australian Energy Market Commission's (AEMC's) final decision on meter data acquisition and our latest results from the trials we are undertaking on smart meter data.	Attachment 6.04.

6.3 Our proposed opex for 2025-30

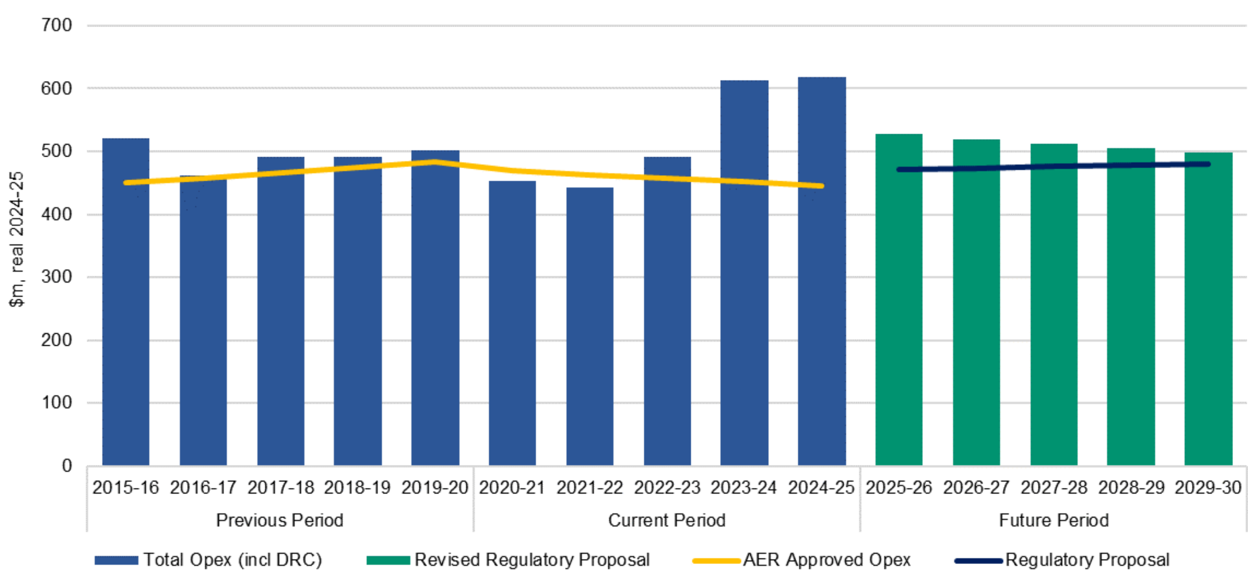
Our revised opex forecast of $2,562.9 million for the 2025-30 regulatory control period is set out in Table 21. This represents a decrease of 2.1 per cent relative to our actual/forecast opex for the current regulatory control period and is in line with historical opex (refer to Figure 9).

Table 21: Forecast opex 2025-30 ($m, real 2024-25)

$m, real 2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	Total[1]
Opex (excl. debt raising costs)	519.7	510.6	504.4	496.7	490.4	**2,521.8**
Debt raising costs	7.9	8.1	8.2	8.4	8.5	**41.1**
Total opex[1]	**527.6**	**518.7**	**512.6**	**505.1**	**498.1**	**2,562.9**

Note 1: Totals may not add due to rounding.

Figure 9: Opex between 2015 to 2030 ($m, real 2024-25)



6.4 Our forecasting approach

Consistent with our Regulatory Proposal, Ergon Energy Network has applied a base-step-trend methodology to calculate the majority of the opex forecast in our Revised Regulatory Proposal. This approach is in line with the AER's *Expenditure Forecast Assessment Guideline* and is the same approach used to set the allowance for the current regulatory control period.

The process of forecasting opex involves five steps as summarised in Figure 10.

Figure 10: Approach to forecasting opex

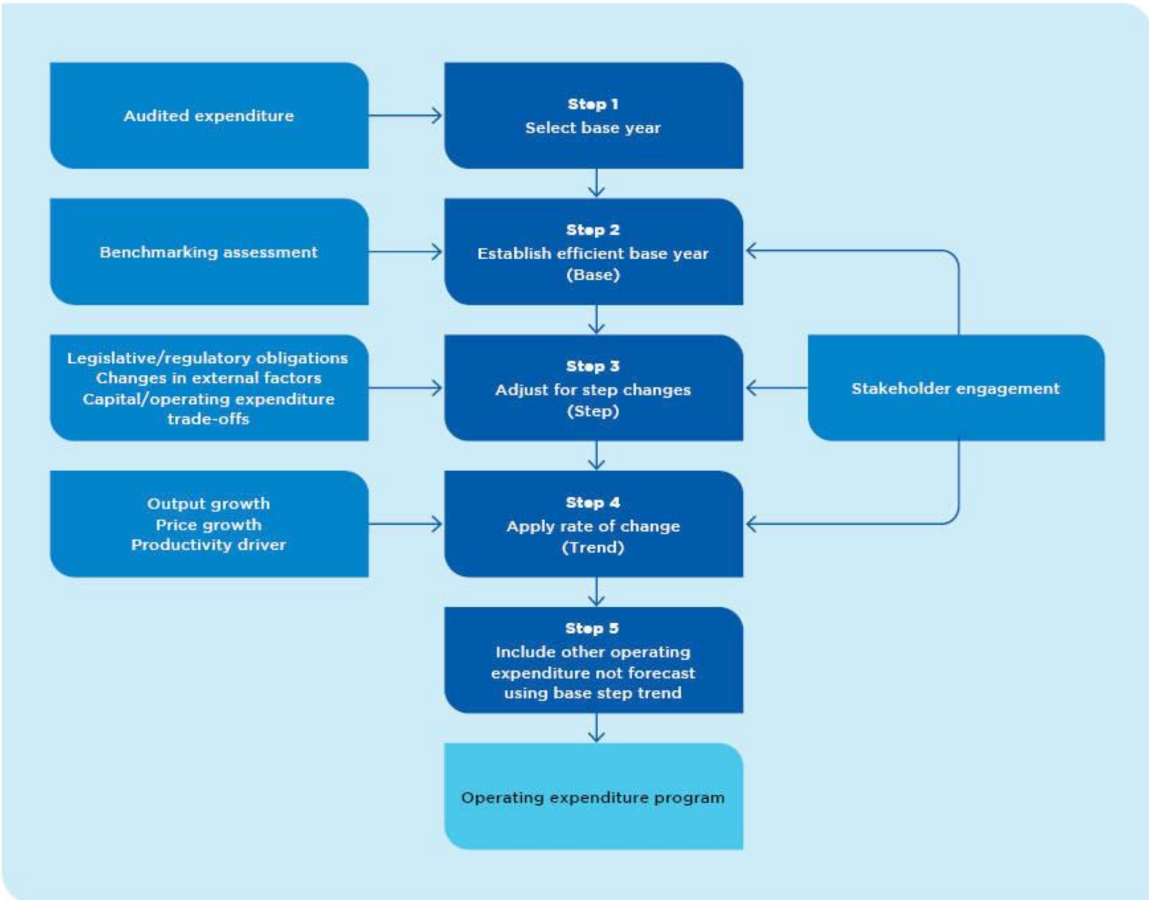


Table 22 outlines the key components of the base-step-trend approach and how each component differs from our initial proposal and the AER's alternative estimate in its Draft Decision.

Table 22: Key components of the opex forecast for 2025 to 2030

Component	Regulatory Proposal	AER Alternative Estimate	Revised Regulatory Proposal
Base opex and efficiency	We selected a base year of 2023-24 and used forecast data as the basis. We tested the base year for efficiency using the *2023 Annual Benchmarking Report* and applied a 2.3 per cent efficiency adjustment.	The AER used our forecast data for 2023-24 as the base year. The AER tested the base year using the *2023 Annual Benchmarking Report*, with some revisions for updated data, and applied a 1.9 per cent efficiency adjustment.	We have used our actual data for 2023-24 as the base year. We tested our actual base year for efficiency using the preliminary results of the *2024 Annual Benchmarking Report*. The raw efficiency adjustment is estimated at 16.9 per cent. We have removed some costs (for extreme weather events and provisions) to arrive at an efficiency adjustment of 7.8 per cent. Additional information is included in section 6.4.1.
Transition costs	We did not include transition costs in our Regulatory Proposal.	The AER included $18.3 million for transition costs in its alternative estimate.	We have included $83.1 million in transition costs in our Revised Regulatory Proposal based on our updated 2023-24 base year costs.
Base year adjustments	Adjustments to the base year were made to remove costs such as the Electrical Safety Office (ESO) levy ($7.7 million) (which will be treated as a jurisdictional scheme)[66] and property leases ($5.9 million) (which will be treated as capex).[67]	The AER applied the same base year adjustments as our proposal.	We have applied adjustments for the ESO levy (actual $6.8 million) and property leases (actual $5.1 million).
Step changes	A step change of $6.8 million was included for smart meter data, representing a new cost that will be incurred during the period.	The AER substituted our step change with $0 million.	We have updated our smart meter data business case and have included a step change of $10.0 million. Additional information is included in section 6.4.2.
Rate of change	We trended the base year forward to reflect changes in outputs, prices and productivity. A productivity rate of 1.0 per cent per annum was applied.	The AER trended the base year forward to reflect changes in outputs, prices, and productivity. A productivity rate of 0.5 per cent per annum was applied.	We trended the base year forward to reflect changes in outputs, prices and productivity. A productivity rate of 1.0 per cent per annum was applied. Additional information is included in section 6.4.3.

[66] The ESO levy has been reclassified as a Jurisdictional Scheme, effective 1 July 2025 and therefore is no longer funded through the opex allowance. Instead, the levy costs will be funded through Jurisdictional Scheme charges.
[67] The previous accounting standard, AASB 117 Leases, was replaced by AASB 16 Leases on 1 July 2019. AASB 16 Leases introduces a new requirement for a lessee to recognise assets and liabilities for the rights and obligations created by leases. For regulatory reporting purposes, Ergon Energy Network will adopt this change from 1 July 2025.

Component	Regulatory Proposal	AER Alternative Estimate	Revised Regulatory Proposal
Other opex	We included $43.1 million in debt raising costs which were forecast using the AER's benchmark method.	The AER included $39.9 million in debt raising costs which were forecast using the AER's benchmark method.	We included $41.1 million in debt raising costs which were forecast using the AER's benchmark method. The calculation of our debt raising costs is set out in the Post Tax Revenue Model (PTRM) (Attachment 8.03).

6.4.1 Efficiency of the base year

For the 2025-30 regulatory control period, we have selected a base year of 2023-24. We chose 2023-24 as the base year because it continues the well-accepted regulatory practice of using the most recent year for which audited data is available by the time of the final distribution determination.

We are unable to use 2022-23 as a base year as it does not provide a realistic expectation of on-going costs. The 2022-23 year does not include the full increase in external contractor costs, general inflationary increases and internal labour costs which we have experienced recently. We anticipate our on-going annual opex to provide SCS services over the 2025-30 regulatory control period to be higher than this level. In addition, we are unable to use 2024-25 as a base year as audited data will not be available at the time of the Final Decision.

As previously discussed, our Regulatory Proposal was prepared using a forecast 2023-24 base year. Since the submission of our Regulatory Proposal our costs have increased. These increases are due to both internal factors (including labour costs and FTE increases) and external factors (including general inflationary pressure, contractor costs and extreme weather events). We have used actual base year opex of $585.0 million ($2023-24) in our Revised Regulatory Proposal.

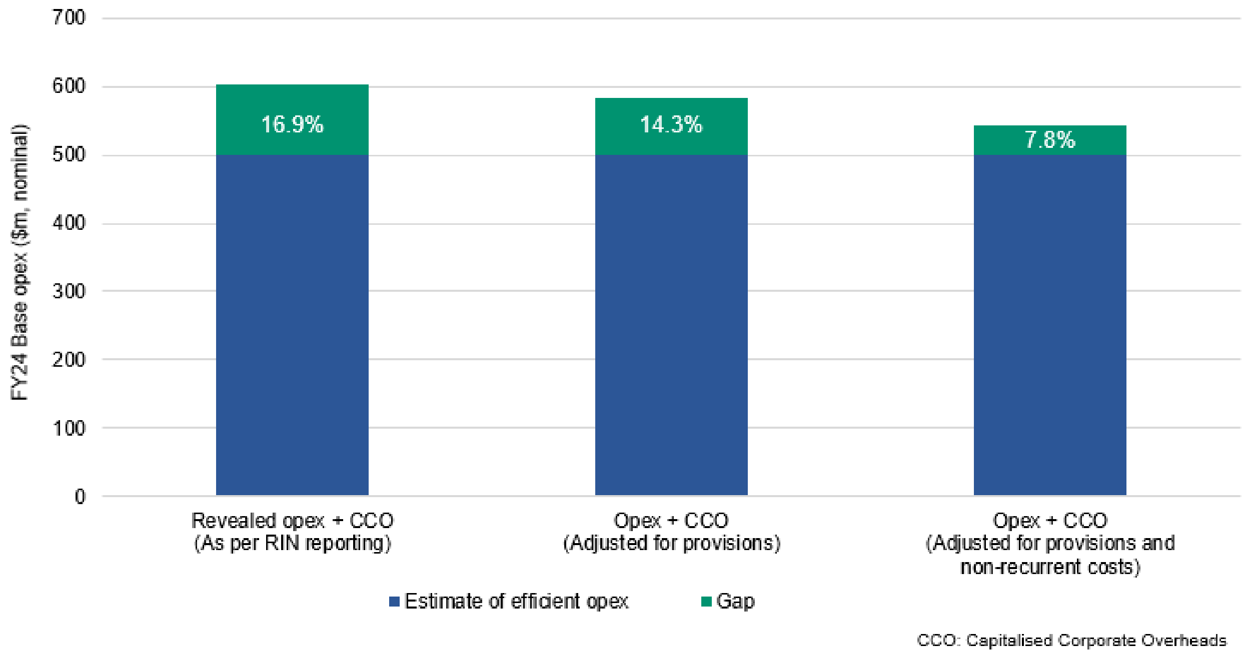
The AER is expected to release its latest *Annual Benchmarking Report: Electricity distribution network service providers* in November 2024 (2024 *Annual Benchmarking Report*). Ergon Energy Network received a copy of the preliminary results in August 2024.

We have reviewed our revealed base year opex against the expected outcomes of the preliminary economic benchmarking models and analysis applied in recent determinations. As a result of our assessment, when using the 2023-24 actual costs as incurred, Ergon Energy Network is expected to receive a 16.9 per cent efficiency adjustment to the base year. Further detail on how our base year opex compares to economic benchmarks is included in the *Frontier Economics - Estimates of efficient base year opex for Energex and Ergon Energy* (Attachment 6.03).

We have reviewed our revealed costs for 2023-24 and have excluded non-recurrent costs. During the 2023-24 base year, there were significant weather events, including Cyclone Jasper in December 2023. We have removed $41.0 million ($2023-24) in emergency response costs based on the difference between our actual costs and a historical five-year average. We have also excluded the movement in provisions from our base year costs, in line with previous AER determinations.

Following the adjustments, we have included a 7.8 per cent efficiency adjustment to our base year costs in the SCS opex model. The above adjustments are illustrated in Figure 11.

Figure 11: 2023-24 base year efficiency adjustments



6.4.2 Step changes

The *Better Resets Handbook* notes that step changes may arise from a change in regulatory obligations, a capex/opex substitution or a change driven by major external factor(s) outside the control of a business.[68] In our Regulatory Proposal, Ergon Energy Network identified and quantified one significant cost for the 2025-30 regulatory control period which was treated as a step change.

The proposed step change for smart meter data relates to the acquisition, processing and use of smart meter data.

In the Draft Decision, the AER rejected the proposed $6.8 million for the smart meter data step change and substituted a forecast of $0.0 million.[69]

The AER and EMCa provided feedback which included:

- in our face-face workshop, EMCa questioned the unit rate for live data acquisition, thinking it was too low and did not reflect the likely costs associated with the initiative. We have looked at the costs of our current data acquisition and revised the unit rate estimates up in line with this feedback
- our key assumptions around the safety benefits of live data and 6-hourly data were higher than they had expected. We have analysed our current live data trials and utilised these findings to revise down our expectation on resolving safety and reliability issues on our network in line with this data, and
- since our Regulatory Proposal, the AEMC has released its draft decision on *Accelerating smart meter data deployment*.[70] This has clarified that only 24-hour data is available free of charge and that there will be Business-to-Business (B2B) costs payable by a Network

[68] AER, *Better Resets Handbook – Towards consumer centric network proposals*, December 2021, p. 28.
[69] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Attachment 6 – Operating expenditure*, September 2024, p.39.
[70] AEMC, *Accelerating Smart Meter Deployment, Draft rule determination*, 4 April 2024.

Service Provider to acquire more granular data. We had originally thought that the data would be 6-hourly, and no B2B costs would be incurred. This has been incorporated into our CBA modelling. The AER also released guidance on the carbon emissions price,[71] which we have utilised in our revised modelling in valuing the benefits of smart meter data as it relates to the integration of distributed energy resources.

In this Revised Regulatory Proposal, we have forecast a step change of $10.0 million. Our preferred option (Option 2) includes:

- acquiring advanced (near real-time) power quality data for 25 per cent of the available smart meters, which is the critical mass of data required for a highly accurate real-time assessment of our low voltage network to enable the integration of distributed energy resources and export at the most efficient level. This would provide enough data to be able to respond quicker to network outages on distribution transformers and service lines
- acquiring basic power quality data for the remaining 75 per cent of smart meters for our overhead service lines only. This will enable us to detect emerging defects and failures on our service lines to prevent safety and reliability issues for our customers. This data is assumed to be free of charge in accordance with the AEMC's recommendation, and
- provision of a data platform and B2B system to land and analyse the smart meter data that we acquire. This cost will be shared across Energex and Ergon Energy Network and has been assigned proportionally according to the number of smart meter points we expect in each network.

Table 23 summarises the costs we are forecasting for the 2025-30 regulatory control period associated with acquiring smart meter data.

Table 23: Forecast step changes for 2025-30 period

$m, real 2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	Total[1]
Smart meter data business case	3.1	2.0	2.3	2.6	2.8	**12.9**
Costs included in 2023-24 base year	0.6	0.6	0.6	0.6	0.6	**2.9**
Smart meter data included in opex model	2.5	1.5	1.7	2.0	2.3	**10.0**

Note 1: Totals may not add due to rounding.

We have resubmitted our revised Smart Meter Data Acquisition Business Case for the AER's consideration (refer to Attachment 6.04).

6.4.3 Rate of change

The efficient base year is trended forward over the regulatory control period to reflect changes in price, outputs and productivity.

[71] AER, *AER guidance and explanatory statement - Valuing emissions reduction*, May 2024, p. 4.

6.4.3.1 Price growth

Our price trend adjustments in this Revised Regulatory Proposal are based on the average of the updated forecasts prepared by Oxford Economics (Attachment 6.02), and the forecast commissioned by the AER (Deloitte Access Economics) used in its Draft Decision.[72] The forecast price growth rates are provided in Table 24.

Table 24: Forecast real price growth 2025-30

Per cent	2025-26	2026-27	2027-28	2028-29	2029-30
Real labour forecast – Oxford Economics	0.64%	1.05%	1.05%	1.28%	1.38%
Real labour forecast – Deloitte Access Economics	0.61%	0.79%	0.77%	0.88%	1.09%
Average of real labour forecasts	0.63%	0.92%	0.91%	1.08%	1.23%
Superannuation guarantee	0.50%	0.00%	0.00%	0.00%	0.00%
Average plus superannuation guarantee	1.13%	0.92%	0.91%	1.08%	1.23%
Price growth (assuming 59.20% labour)	0.67%	0.55%	0.54%	0.64%	0.73%

6.4.3.2 Output growth

We have updated the output growth forecasts in our Revised Regulatory Proposal to reflect actual 2023-24 data and the latest available forecasts. We have applied the output change measures and respective weightings in the preliminary *Quantonomics Report*[73] expected to be released with the AER's 2024 *Annual Benchmarking Report*. Our forecast output growth rates are outlined in Table 25.

Table 25: Forecast output growth 2025-30

	Average weighting	2025-26	2026-27	2027-28	2028-29	2029-30
Customer numbers	39.2%	805,074	812,032	818,852	825,521	832,019
Circuit length	19.9%	155,312	155,760	156,222	156,679	157,150
Ratcheted maximum demand	41.0%	3,340	3,349	3,387	3,392	3,415
Average output growth		0.83%	0.50%	0.85%	0.44%	0.64%

6.4.3.3 Productivity growth

Given the affordability concerns raised by our customers, our Executive Management and Board decided to apply a 1.0 per cent annual productivity rate to the forecast opex in our Regulatory Proposal. This exceeded the AER's standard rate of 0.5 per cent. Ergon Energy Network is maintaining its commitment and has applied a productivity rate of 1.0 per cent in our Revised Regulatory Proposal.

[72] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Attachment 6 – Operating expenditure*, September 2024, p.35.
[73] The AER provided the Quantonomics Report to all DNSPs as part of its standard feedback process for its Annual Benchmarking Report.

Productivity improvements can result from technical change, efficiency, or economies of scale. The reductions in opex due to both the applied efficiency adjustment and productivity factor will be a significant challenge for our business as the costs of managing our network continue to rise. However, we are committed to continuing to deliver a safe, secure and reliable network in the 2025-30 regulatory control period while recognising customers' affordability concerns. Further detail on how Ergon Energy Network is proposing to achieve the productivity improvements is included in Attachment 6.05.

6.5 Supporting documentation

The following documents support this chapter:

Document Name	Reference	File name
Ergon SCS Opex Model	6.01	Ergon - 6.01 - Model - SCS Opex model - November 2024 - public
Input cost escalation forecasts to 2029/30	6.02	Ergon - 6.02 - Oxford Economics Australia - Input Cost Escalation Forecasts to 2029/30 - November 2024 – public
Frontier Economics – Estimates of efficient base year opex	6.03	Ergon - 6.03 - Frontier Economics - Estimates of efficient base year opex for Energex and Ergon Energy - October 2024 – public
Smart Meter Data Acquisition Business Case	6.04	Ergon - 6.04A - Business Case - Smart Meter Data Acquisition - November 2024 - public Ergon - 6.04A - Business Case - Smart Meter Data Acquisition - November 2024 - confidential Ergon - 6.04B - NPV Model - Smart Meter Data Acquisition - November 2024 - confidential
Productivity Initiatives	6.05	Ergon - 6.05 - Productivity Initiatives - November 2024 - confidential

7. Incentive Schemes

Key messages:

- Ergon Energy Network supports the application of incentive schemes to DNSPs.
- We continue to support the application of the STPIS, CESS, DMIS and DMIAM to Ergon Energy Network in the 2025-30 regulatory control period. However, we now propose that the EBSS should be suspended in this period.
- We accept the AER's Draft Decision that the customer service (telephone answering) component of the STPIS should remain. Customers have indicated that they can "live with" this decision given the CSIS will not apply to Ergon Energy Network in 2025-30.
- In the absence of the CSIS, we remain committed to publishing a Customer Service Performance Measures Scorecard independently of the regulatory determination process to provide greater transparency of our performance against the measures most valued by our customers.

7.1 Overview of the AER's Draft Decision

We consider that the application of incentive schemes is in the long-term interests of our customers. These schemes incentivise networks like Ergon Energy Network to run efficient businesses so that customers pay no more than is necessary for the services they require and ensure that the right levels of service are delivered to customers.

Table 26 summarises what we proposed and the AER's Draft Decision on incentive schemes for the 2025-30 regulatory control period.

Table 26: Summary of the AER's Draft Decision on incentive schemes

Scheme	Regulatory Proposal	Draft Decision
CESS	Apply for 2025-30. CESS penalties of $714.4 million.	Accepted application for 2025-30. Recalculated CESS penalties to $490.2 million due to decision on ex-post capex.
EBSS	Apply for 2025-30. EBSS negative carryovers of $199.0 million.	Accepted application for 2025-30. Recalculated EBSS carryovers to $196.8 million based on updated inputs
STPIS	Apply for 2025-30. The customer service component of the STPIS (telephone answering) should not apply and the overall revenue at risk cap should be reduced to ±1.8 per cent of annual forecast revenue due to telephone answering not applying. Performance targets and incentive rates updated for 2025-30.	Accepted application for 2025-30. Included telephone answering component of STPIS and consequently set revenue at risk at ±2.0 per cent of annual forecast revenue. Performance targets and incentive rates to be recalculated with updated inputs for Final Decision.
DMIS	Apply for 2025-30.	Accepted application for 2025-30.

Scheme	Regulatory Proposal	Draft Decision
DMIAM	Apply for 2025-30. Allowance of $7.5 million.	Accepted application for 2025-30. Allowance to be set in Final Decision.
CSIS	Not apply for 2025-30.	Accepted.
ESIS	Not apply for 2025-30.	Accepted.

7.2 Our response to the AER's Draft Decision

We have modified our position on which incentive schemes should apply to Ergon Energy Network for the 2025-30 regulatory control period. Our revised position is to not apply the EBSS for the 2025-30 regulatory control period for the reasons set out in section 7.4.

Table 27 summarises our response to the key issues raised by the AER in its Draft Decision regarding the application of the incentive schemes.

Table 27: How we have responded to AER's Draft Decision on incentive schemes

Issue in Draft Decision	Our response	More information
CESS	We have updated the CESS revenue adjustment calculations.	Section 7.3.
EBSS	We have changed our position and propose that the EBSS should be suspended.	Section 7.4.
STPIS	We have updated the calculations of our STPIS targets and incentive rates. We have accepted the AER's Draft Decision to apply the customer service component (telephone answering) of the STPIS.	Section 7.5.
DMIS and DMIAM	We have updated the DMIAM allowance calculations.	Section 7.6.

7.3 Capital Expenditure Sharing Scheme

The CESS incentivises us to undertake efficient capex over the regulatory control period by providing financial rewards and penalties for efficiency gains and losses on capex, respectively.

7.3.1 Revenue impact in the 2025-30 period

In the Regulatory Proposal we estimated total CESS penalties of $714.4 million (real $2024-25), consisting of:

- $625.9 million revenue decrements for spending more than the efficient capex forecast set by the AER for the 2020-25 regulatory control period, and
- $88.6 million revenue decrements for the true-up for the CESS payment calculated in the previous determination for the 2019-20 year.

The AER's Draft Decision estimated total CESS penalties of $490.2 million.[74] The material reduction in the CESS penalties was due to the AER's decision on our 2018-23 ex-post capex review. Given that the AER materially reduced the capex that is allowed to be rolled into the RAB for the 2018-23 ex-post review period, this materially reduced the penalties we initially estimated to prevent us from being penalised more than 100 per cent of the additional capex we incurred above the AER's substitute forecast. In addition, the AER also updated the other inputs, including the consumer price index (CPI) and the rate of return (WACC) to reflect up-to-date information.

Our response to the AER's Draft Decision on total CESS penalties is summarised in Table 28. We accept the AER's ex-post capex review decision but have updated the revenue decrements for spending above the AER's allowances for the 2020-25 regulatory control period to reflect our actual capex for the 2023-24 year and updated forecast for the 2024-25 year. This results in total revised CESS penalties of $576.6 million (real $2024-25).

Table 28: Summary of our response to AER's Draft Decision on total CESS penalties

$m, real 2024-25	Regulatory Proposal	Draft Decision	Difference to Regulatory Proposal	Summary of our response	Revised Regulatory Proposal	Difference to Regulatory Proposal
CESS penalties	-625.9	-466.1	159.8	Accept	-552.7	73.2
CESS true-up for 2019-20	-88.6	-24.0	64.6	Accept	-23.9	64.7
Total[1]	**-714.4**	**-490.2**	**224.4**	**Accept**	**-576.6**	**137.8**

Note 1: Totals may not add due to rounding.

7.3.2 Application of the CESS in the 2025-30 regulatory control period

In the Regulatory Proposal, and consistent with the F&A, we proposed the continued application of the CESS in the 2025-30 regulatory control period. The AER's Draft Decision proposed that the CESS would continue to apply.[75] We accept the AER's Draft Decision.

7.4 Efficiency Benefit Sharing Scheme

The EBSS is intended to provide a continuous incentive for DNSPs to pursue efficiency improvements in opex and to share these with customers. The EBSS is intrinsically linked to the revealed cost base-step-trend approach, where forecast opex is based on a network business's recent actual opex from a single year (the base year). The opex is forecast by trending forward the base year opex, accounting for changes in key inputs costs, outputs and productivity. Other efficient costs not captured in the base year are added as step changes in the forecast.

The EBSS is intended to address two potential incentive problems associated with the revealed cost forecasting approach:

- the incentive to increase opex in the base year so as to increase the forecast opex, and
- the incentive to defer efficiency improvement until after the base year so as to avoid a lower opex forecast.

[74] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Attachment 9 – Capital expenditure sharing scheme*, September 2024, p. 2.
[75] Ibid, p. 2.

The combination of the EBSS and the revealed cost forecasting approach means the network business earns the same reward and penalty in each year of the regulatory control period for efficiency gains or losses. At a 6 per cent real WACC, and with network businesses holding efficiency gains or losses for six years, this results in network businesses sharing opex efficiency gains and losses approximately 30:70 with customers. It is important to reiterate that the EBSS only works as intended where the opex forecast is based on the network business's actual revealed cost. Departing from the business's actual costs, for example by substituting benchmarking opex for actual costs, distorts how the EBSS works and can potentially result in a business being penalised more than 100 per cent of the efficiency losses. It is for this reason that the EBSS should only apply where the AER uses actual revealed costs to forecast opex.

In our Regulatory Proposal, we proposed that the EBSS should apply in the 2025-30 regulatory control period and included $199.0 million in negative EBSS carryovers (i.e. penalties) from the current 2020-25 regulatory control period. These negative carryovers were based on our forecast base year opex (i.e. 2023-24). While we did apply an efficiency adjustment to the base year and thereby did not rely on our actual costs, we considered that the adjustment was not material enough to distort how the EBSS works and thus proposed that the EBSS should continue to apply and included the negative carryovers. The AER's Draft Decision was to include $196.8 million in negative EBSS carryovers, based on the most recent inflation data.[76]

Our response to the AER's Draft Decision on EBSS penalties is summarised in Table 29.

Table 29: Summary of our response to AER's Draft Decision on EBSS penalties

$m, real 2024-25	Regulatory Proposal	Draft Decision	Difference to Regulatory Proposal	Summary of our response	Revised Regulatory Proposal	Difference to Regulatory Proposal
EBSS penalties	-199.0	-196.8	2.2	Modify	0.0	199.0

Note 1: Totals may not add due to rounding.

The position for our Revised Regulatory Proposal has changed from that proposed in our Regulatory Proposal. We now propose that:

- the penalties from the application of the EBSS in the current 2020-25 regulatory control period should not be applied in the 2025-30 regulatory control period, and
- the EBSS should be suspended for the 2025-30 regulatory control period.

The reason for the change in our position is that our actual opex for 2023-24 (the base year) has significantly exceeded the forecast that we provided in the Regulatory Proposal and used for the AER's Draft Decision. We previously advised the AER of this likely outcome, which was noted in the Draft Decision.

As a result of the increase in the base year, our analysis indicates that the benchmark efficiency adjustment for Ergon Energy Network (excluding movement in provisions) has increased to approximately 14.3 per cent.[77] This efficiency adjustment includes uncontrollable (and one-off) storm costs, which we have adjusted for in revising our opex forecasts. However, under the EBSS, these costs are not an approved exclusion. This means that, while they are excluded from the base year (in forecasting opex), we are penalised under the EBSS, distorting the sharing of the efficiency losses.

[76] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Attachment 8 – Efficiency benefit sharing scheme*, September 2024, p. 1.
[77] We have removed non-recurrent storm costs from our base year, to apply an adjustment of 7.8 per cent in the SCS opex model.

We consider that the magnitude of the efficiency adjustment means we are no longer relying on our revealed costs to forecast our opex. Instead, we are primarily relying on benchmarking. The opex we have proposed in Chapter 6 is $2,562.9 million. If our revealed costs were used to forecast opex, the forecast is estimated to be $2,904.9 million, $342.0 million higher than the benchmark estimate.

As mentioned previously, the EBSS is intended to work in conjunction with a revealed cost forecasting approach. When used together it allows for the fair sharing of efficiency gains and losses. As revealed costs (in 2023-24) have not been applied in forecasting our opex (see Chapter 6), we consider it is not appropriate to apply the associated penalties to our revenues for the 2025-30 regulatory control period. This is because:

- if the penalties were included for 2025-30 (which have been recalculated at $575.7 million based on our actual 2023-24 opex), in addition to an efficiency adjustment in the base year, Ergon Energy Network would carry a greater share of losses than initially intended when the EBSS was applied for the 2020-25 regulatory control period
- it is not consistent with the intended operation of the EBSS and the objective of fairly sharing efficient losses as defined under the NER, and
- this position is consistent with previous AER determinations, namely the 2024-29 Draft Determination for Evoenergy.[78]

In addition, as it is uncertain whether revealed costs for the 2025-30 regulatory control period will be relied on in forecasting future (2030-35) opex, our position is that the EBSS should also not be applied in the 2025-30 regulatory control period. Ergon Energy Network already has an incentive to make efficiency improvements in the 2025-30 regulatory control period given our actual opex has been subject to an efficiency adjustment.

7.5 Service Target Performance Incentive Scheme

The STPIS incentivises us to maintain and improve service performance where customers are willing to pay for the improvements. The scheme balances the incentives provided under the current regulatory framework to reduce expenditure with the need to maintain and improve service performance.

In our Regulatory Proposal, we supported the F&A position to continue to apply version 2.0 of the STPIS in the 2025-30 regulatory control period. We also proposed that the customer service component of the STPIS (telephone answering) should not apply and, with the proposed removal of the customer service component of the STPIS, that the overall revenue at risk cap be reduced to ±1.8 per cent from the current ±2.0 per cent. This is because a ±0.2 per cent revenue at risk cap currently applies to the customer service component.

The AER’s Draft Decision did not accept the removal of the customer service (telephone answering) component of the STPIS due to the absence of a CSIS and the importance of phone communications in emergency events.[79]

Our VOC Panel recommended the removal of the customer service (telephone answering) component of the STPIS because panel members considered that we should not be incentivised for good customer service. In light of this position, we explored the AER’s Draft Decision on STPIS with our VOC Panel in October 2024. The views of the Panel were that they could “live with” the

[78] AER, *Draft Decision, Evoenergy Electricity Distribution Determination 2024 to 2029, Attachment 8 – Efficiency benefit sharing scheme*, September 2024, pp. 4-5
[79] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Attachment 10 – Service target performance incentive scheme*, September 2024, pp. 6-8.

continuation of the customer service (telephone answering) component of the STPIS because the AER accepted that a CSIS would not apply to Ergon Energy Network and because we remain committed to publishing a Customer Service Performance Measures Scorecard.

While we are disappointed that the AER did not place a greater weight on the views of our VOC Panel, we can accept the inclusion of the customer service (telephone answering) component of the STPIS.

Table 30 sets out how we have responded to the Draft Decision on key STPIS elements.

Table 30: How we have responded to AER's Draft Decision on STPIS elements

Matter	Regulatory Proposal	Draft Decision	Our Response
Revenue at risk	±1.8 per cent.	±2 per cent.	Accept.
Segmenting of network	Urban, short rural and long rural.	Accepted.	Accept.
Applicable parameters for the s-factor	Reliability of supply: system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI).	Not accepted as also applying customer service (telephone answering) parameter.	Accept.
Performance targets	Based on the average performance over the past five regulatory years.	Accepted.	Accept.
Criteria for excluding certain events from s-factor calculations	Applied the methodology indicated in version 2.0 including the 2.5 beta method for calculating major event days.	Accepted.	Accept.
Incentive rates	Applied the 2019 value of customer reliability (VCR) adjusted to June 2024 CPI values to set incentive rates for SAIDI and SAIFI.	Accepted.	Accept.
Guaranteed service level component	Not applied (a jurisdictional guaranteed service level scheme applies).	Accepted.	Accept.

7.5.1 Proposed performance targets and incentive rates

We have updated our STPIS reliability performance targets and incentive rates to take into account our actual performance for 2023-24 and updated inputs used in calculating incentive rates. We note that the revised incentive rates are a placeholder and will be updated in the AER's Final Decision to incorporate updated forecast inputs, including the AER's revised VCR study due to be published in December 2024. The updated targets and incentive rates are provided in Table 31 and Attachment 7.04.

Table 31: Updated proposed STPIS targets and incentive rates

Proposed targets	Performance target	Incentive rate
Unplanned SAIDI		
Urban	122.0950	0.01903
Short rural	280.0254	0.02482
Long rural	789.3980	0.00501
Unplanned SAIFI		
Urban	1.2169	1.27260
Short rural	2.3538	1.96841
Long rural	4.5277	0.58228
Customer Service		
Telephone answering		-0.04000

7.6 Demand Management Incentive Scheme and Demand Management Innovation Allowance Mechanism

We accept the AER's Draft Decision to apply the DMIS and DMIAM to Ergon Energy Network for the 2025-30 regulatory control period.[80] The DMIS incentivises us to undertake efficient expenditure on relevant non-network options relating to demand management. The DMIAM provides funding for research and development in demand management projects that have the potential to reduce long-term network costs.

We have updated our proposed DMIAM allowance to $7.7 million based on the outputs of our revised PTRM. We accept that the final amount of the DMIAM allowance will be based on the final PTRM.

7.7 Supporting documentation

The following documents support this chapter:

Document Name	Reference	File name
SCS CESS Model	7.01	Ergon - 7.01 - SCS CESS Model - November 2024 - public
SCS CESS True-Up Model	7.02	Ergon - 7.02 - CESS True-Up Model - November 2024 - public
SCS EBSS Model	7.03	Ergon - 7.03 - EBSS Model - November 2024 - public
STPIS Targets and Incentive Rates Model	7.04	Ergon - 7.04 - STPIS Targets and Incentive Rates - November 2024 - public

[80] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Chapter 11 - Demand management incentive scheme and Demand management innovation allowance mechanism*, September 2024, pp. 1-2.

8.
Annual Revenue Requirement

Key messages:

- We have revised our proposed revenue for the 2025-30 regulatory control period to account for revisions to other elements of our proposal.
- Our revised proposed revenue of $7,952.1 million (real $2024-25, unsmoothed) is 1.7 per cent above our initial Regulatory Proposal and 3.7 per cent above the AER's Draft Decision.

8.1 Overview of the AER's Draft Decision

The revenue requirement is the total revenue for the 2025-30 regulatory control period that we require to enable us to continue to build and maintain a safe and reliable network.

In our Regulatory Proposal, we proposed an annual revenue requirement of $7,818.9 million (real $2024-25, unsmoothed), which was 15.1 per cent above our current period revenue. The increase in revenue was driven by uncontrollable factors such as rising interest rates and inflation as well as increasing capex and opex requirements for our business.

The AER's Draft Decision reduced our proposed revenue by $147.6 million (or 1.9 per cent) to $7,671.3 million. The revenue reductions were mainly due to the AER's Draft Decision to reduce our ex-post period (2018-23) capex that was allowed to be rolled into the RAB and also our proposed forecast capex for the 2025-30 regulatory control period. The revenue reductions from the capex decisions were offset by reductions in the incentive scheme penalties and increases in tax allowances. The AER also made several updates to other key inputs such as the rate of return and expected inflation which had minor impacts on revenue.[81]

8.2 Our response to the AER's Draft Decision

We have revised our proposed forecast revenue for the 2025-30 regulatory control period to $7,952.1 million (real $2024-25, unsmoothed) as set out in Table 32. This is $280.8 million more than the AER's Draft Decision revenue and $133.2 million more than our Regulatory Proposal.

Table 32: Our revised proposed revenue for the 2025-30 regulatory control period

$m, real 2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	Total
Return on capital	906.3	929.3	955.8	987.4	1,020.0	**4,798.8**
Regulatory depreciation	185.0	205.1	227.6	246.1	252.7	**1,116.5**
Opex	527.6	518.6	512.7	505.1	498.9	**2,562.9**
Revenue adjustments	-113.8	-113.8	-113.8	-113.8	-113.7	**-568.9**
Tax allowance	4.0	7.0	8.9	12.7	10.2	**42.9**
Annual revenue requirement (unsmoothed)	1,509.1	1,546.2	1,591.2	1,637.5	1,668.1	**7,952.1**
Annual expected revenue (smoothed)	1,455.3	1,512.5	1,574.4	1,678.2	1,741.6	**7,962.0**
X factors[1]	-4.55%	-3.93%	-4.10%	-6.59%	-3.77%	

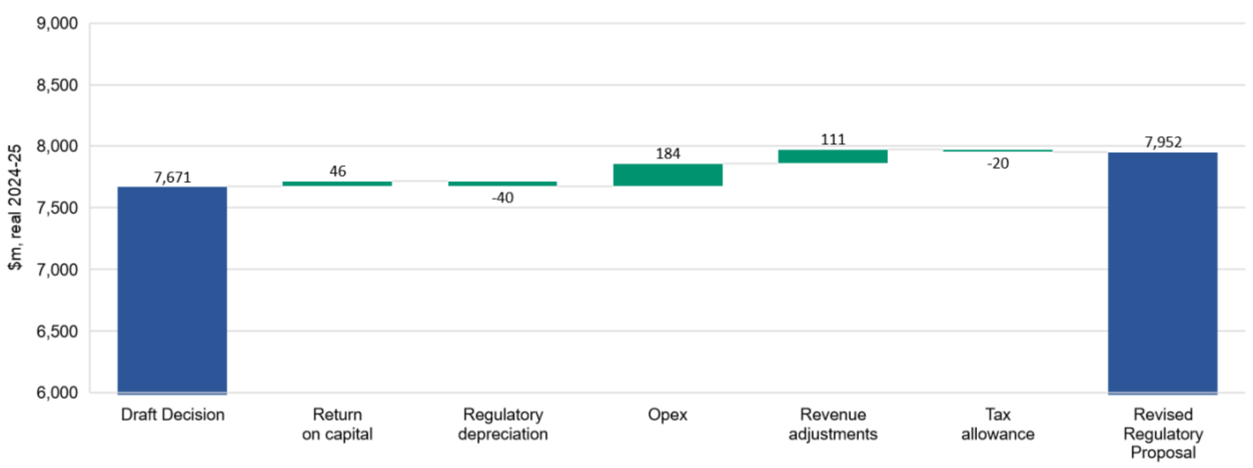
[81] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Attachment 1 – Annual revenue requirement*, September 2024, p. 6.

The increase in our revised revenue above the AER's Draft Decision is due to:

- our updated opex increasing above what we proposed in our Regulatory Proposal and accepted by the AER in the Draft Decision
- our proposal to suspend the application of the EBSS and not apply the penalties for the 2020-25 regulatory control period
- our revised forecast capex being above the AER's Draft Decision, and
- other mechanistic updates we have made to the calculation of our opening RAB to reflect actual expenditure over the 2023-24 year and updated forecast capex for the final year of the current regulatory control period.

Figure 12 sets out the key differences between our Revised Regulatory Proposal building blocks revenue proposal and the AER's Draft Decision.

Figure 12: Changes in revised revenue from the Draft Decision



We note that the revenue will likely change in the AER's Final Decision due to the use of placeholder values for key inputs such as the rate of return and expected inflation in our Regulatory Proposal, the AER's Draft Decision and our Revised Regulatory Proposal.

The following sections provide further details on our response to the AER's Draft Decision.

8.3 Rate of return

Our Revised Regulatory Proposal applies a placeholder rate of return (or WACC) of 5.97 per cent (nominal vanilla) as set out in Table 33. The rate of return is estimated by applying the 2022 *Rate of Return Instrument*. The AER's Draft Decision updated our initial placeholder rate of return and used the prevailing rates at the end of July 2024 for both the return on equity and return on debt.[82] Our Revised Regulatory Proposal uses the prevailing rates at the end of September 2024 for the return on equity. However, for the return on debt, we adopted the approach from our Regulatory Proposal of using the prevailing rates from the previous annual return on debt update.

[82] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Attachment 3 – Rate of return*, September 2024, pp. 1-2.

Table 33: Revised Rate of Return for the 2025-30 regulatory control period

Parameter	Revised Regulatory Proposal
Nominal risk-free rate	3.96%
Market risk premium	6.20%
Equity beta	0.6
Return on equity	7.68%
Return on debt (average)	4.83%
Nominal vanilla WACC (average)	5.97%

The rate of return will be updated in the Final Decision to reflect our nominated averaging periods for the return on equity and return on debt, which the AER approved in the Draft Decision.[83] Consistent with the 2022 *Rate of Return Instrument*, the AER's Final Decision on return on equity will be fixed for the 2025-30 regulatory control period while the return on debt will be updated annually.

8.4 Regulatory asset base

8.4.1 Opening RAB as 1 July 2025

We propose a revised opening RAB value of $15,854.3 million ($, nominal) as at 1 July 2025 as set out Table 34. Our revised opening RAB is $288.2 million higher than the AER's Draft Decision.

Table 34: Revised RAB for the 2020-25 regulatory control period

$m, nominal	2020-21	2021-22	2022-23	2023-24	2024-25
Opening RAB	11,533.8	11,755.1	12,308.1	13,549.3	14,624.8
Net Capex	570.8	609.0	771.6	1,065.5	1,256.0
Straight-line Depreciation	-448.7	-467.3	-494.3	-539.0	-575.3
Indexation	99.2	411.2	963.9	549.0	438.7
Interim closing RAB	11,755.1	12,308.1	13,549.3	14,624.8	15,744.2
Adjustment for previous regulatory control period					124.1
Ex-post adjustments					-67.7
Final year adjustment					53.7
Closing RAB as at 30 June 2025					15,854.3

The Draft Decision reduced our proposed opening RAB value of $16,253.0 million ($, nominal) by $686.9 million due the AER's ex-post review decision to disallow $504.1 million ($, nominal) actual capex for the 2018-19 to 2022-23 period from being rolled into the RAB.[84] Our Board has accepted the AER's Draft Decision on the ex-post review amount to be rolled into the RAB but we submit that the volumes of assets replaced were prudent and efficient.

[83] Ibid, p. 2.
[84] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Attachment 2 – Regulatory asset base*, September 2024, p. 1.

Apart from the ex-post review decision, the Draft Decision accepted our proposed approach to calculating the opening RAB as at 1 July 2025, including our proposals to:

- self-fund the additional capex in ICT over the ex-post period (2018-23), and
- capitalise lease costs in accordance with the accounting standard (AASB 16) and add our existing lease costs to the RAB with a remaining asset life of 4.3 years.[85]

In addition, the Draft Decision made several mechanistic updates to the calculation of the opening RAB, including updating for actual CPI for 2023-24, forecast CPI for 2024-25 and the 2024-25 annual rate of return update. The AER also made other minor amendments that we agreed to, including:

- updating forecast inflation for 2018-19 and 2019-20 to be consistent with the AER's Final Decision PTRM for 2015-20
- updating actual gross capex and asset disposal inputs for 2019-23 to be consistent with the Annual Reporting RINs for these years, and
- updating the asset disposals for 2023-25 for the "Motor Vehicles" asset class to reflect the estimated gross proceeds from sale.

We accept the Draft Decision. However, we have updated the calculation of the opening RAB in the roll forward model (RFM) to reflect:

- actual 2023-24 capex values - our Regulatory Proposal and the Draft Decision used forecast values for 2023-24, and
- updated 2024-25 capex forecasts - we have updated the forecast we included in our initial proposal to reflect our latest data.

8.4.2 Forecast RAB

We propose a revised forecast closing RAB of $20,179.3 million ($, nominal) by 30 June 2030 as set out in Table 35. This is $1,240.0 million higher than the AER's Draft Decision.

Table 35: Revised RAB for the 2025-30 regulatory control period

$m, nominal	2025-26	2026-27	2027-28	2028-29	2029-30
Opening RAB	15,854.3	16,665.4	17,501.2	18,349.9	19,235.2
Net Capex	1,002.4	1,051.7	1,096.4	1,160.7	1,235.0
Straight-line Depreciation	-642.1	-691.9	-746.4	-798.3	-839.0
Indexation	451.8	474.9	498.7	522.9	548.1
Closing RAB	16,665.4	17,501.2	18,349.9	19,235.2	20,179.3

The revised forecast RAB reflects the updates we have made in the PTRM, including the updated opening RAB, our revised forecast capex for the 2025-30 regulatory control period (as explained in Chapter 5) and updated rate of return.

[85] Ibid, p. 16.

8.5 Regulatory depreciation

We propose revised forecast regulatory depreciation of $1,116.5 million (real $2024-25) for the 2025-30 regulatory control period as set out in Table 36. Our revised regulatory depreciation is $39.9 million less than the AER's Draft Decision.

Table 36: Revised Regulatory depreciation for the 2025-30 regulatory control period

$m, real 2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	Total[1]
Straight-line depreciation	624.6	654.0	686.0	713.4	728.9	**3,406.9**
Less Indexation	-439.6	-448.9	-458.4	-467.3	-476.2	**-2,290.4**
Regulatory depreciation	185.0	205.1	227.6	246.1	252.7	**1,116.5**

Note 1: Totals may not add due to rounding.

The AER's Draft Decision accepted our proposed approach to calculating regulatory depreciation, including:

- the use of the straight-line depreciation method
- the continued use of the "year-by-year tracking" approach for implementing straight-line depreciation of existing assets and forecast capex
- the continued use of existing asset classes and standard asset lives, and
- two new asset classes of "Initial leases" and "Lease extensions" for the capitalisation of lease expenditures, with standard asset lives of 10 years and five years respectively.[86]

We accept the AER's Draft Decision. However, we have updated the calculation of regulatory depreciation to reflect:

- the updated opening RAB as at 1 July 2025
- our revised forecast capex, and
- updated rate of return.

We have also used the AER's Draft Decision forecast for expected inflation of 2.85 per cent to calculate the indexation component of regulatory depreciation.[87]

8.6 Opex

We propose revised opex of $2,562.9 million (real $2024-25) as set out in Chapter 6. This is $183.9 million higher than the Draft Decision.[88]

[86] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Attachment 4 – Regulatory depreciation,* September 2024, pp. 1-2.
[87] Ibid, p. 1.
[88] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Overview,* September 2024, pp. 22-23.

8.7 Corporate income tax

We propose revised tax allowances of $42.9 million (real $2024-25) as set out in Table 37. This is $20.3 million less than the Draft Decision.

Table 37: Revised Corporate income tax for the 2025-30 regulatory control period

$m, real 2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	Total[1]
Tax payable	9.2	16.3	20.7	29.6	23.8	**99.7**
Less value of imputation credits	-5.2	-9.2	-11.8	-16.9	-13.6	**-56.8**
Corporate income tax	4.0	7.1	8.9	12.7	10.2	**42.9**

Note 1: Totals may not add due to rounding.

The Draft Decision accepted our proposed approach to calculating corporate income tax, including:

- the calculation of the opening tax asset base (TAB) as at 1 July 2025 in the RFM
- the income tax rate of 30 per cent and value of imputation credits (gamma) of 0.57 as set out in the 2022 *Rate of Return Instrument*
- the approach for immediate expensing of capitalised overheads
- exempting forecast capex for buildings and in-house software for the 2025-30 regulatory control period from the diminishing value tax depreciation method and continuing to apply straight-line tax depreciation for these assets
- the use of the year-by-year depreciation tracking method
- proposed standard tax asset lives, except for "in-house software" which was amended in the Draft Decision to be consistent with the *Income Tax Assessment Act* 1997, and
- two new asset classes of "Initial leases" and "Lease extensions" for the capitalisation of lease expenditures, with standard asset lives of 10 years and five years, respectively.[89]

We accept the AER's Draft Decision. However, we updated the calculation of corporate income tax to reflect an updated opening TAB, revised forecast capex and revised forecast of immediately expensed capex.

8.8 Revenue adjustments

We propose a negative revised revenue adjustment of $568.9 million (real $2024-25) as set out in Table 38. This is $111.0 million lower than the Draft Decision.

Table 38: Revised Revenue adjustments for the 2025-30 regulatory control period

$m, real 2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	Total
CESS	-115.3	-115.3	-115.3	-115.3	-115.3	**-576.6**
EBSS	-	-	-	-	-	**-**
DMIAM	1.5	1.5	1.5	1.6	1.6	**7.7**
Total	**-113.8**	**-113.8**	**-113.8**	**-113.8**	**-113.7**	**-568.9**

[89] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Attachment 7 – Corporate income tax,* September 2024, pp. 1-2.

The changes in our revised revenue adjustments are due to:

- updated CESS penalties to reflect actual 2023-24 capex and an updated forecast 2024-25 capex, and
- our proposal to suspend the EBSS and not apply penalties for the 2020-25 regulatory control period (as explained in Chapter 7).

8.9 Smoothed revenue and X factors

We propose revised smoothed revenue of $7,962.0 million and the X factors set out in Table 39.

Table 39: Revised Smoothed revenue and X factors for the 2025-30 regulatory control period

$m, real 2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	Total[1]
Annual revenue requirement (unsmoothed)	1,509.1	1,546.2	1,591.2	1,637.5	1,668.1	**7,952.1**
Annual expected revenue (smoothed)	1,455.3	1,512.5	1,574.4	1,678.2	1,741.6	**7,962.0**
X factors	-4.55%	-3.93%	-4.10%	-6.59%	-3.77%	

Note 1: Totals may not add due to rounding.

Annual revenue requirements can vary significantly from year-to-year. Revenue smoothing is applied to minimise price volatility. As suggested by the AER in its Draft Decision, our Revised Proposal smoothing profile accounts for the Queensland Government's Solar Bonus Scheme expiring on 1 July 2028. This is consistent with the approach applied by the AER in its Draft Decision for SA Power Networks.[90]

Further, the NER stipulate that the smoothing must be set so as to minimise, as far as reasonably possible, the difference between the annual revenue requirement (unsmoothed) and the expected revenue (smoothed) for the final year of the regulatory control period. The AER's Draft Decision noted that a divergence of up to 3 per cent is reasonable.[91] However, we also note that in the SA Power Networks' Draft Decision, the AER considered it reasonable to relax the threshold to 5 per cent to minimise the first-year price impacts.[92] We have applied the 5 per cent threshold in developing our revised smoothing profile. The divergence between our smoothed and unsmoothed revenue is 4.4 per cent.

8.10 Revised bill impacts

We estimate that total annual network charges (inclusive of transmission charges and jurisdictional schemes) will increase, in nominal terms, by an average of $55 or 5 per cent annually for residential customers, $127 or 5.9 per cent annually for small business customers, and $4,023 or 6.1 per cent annually for a large business connected on the low voltage network.[93] The revised indicative bill impacts are outlined in Table 40.

[90] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Attachment 1 – Annual revenue requirement*, September 2024, pp. 8-9.
[91] Ibid, p. 5.
[92] AER, *Draft Decision, SA Power Networks Electricity Distribution Determination 2025 to 2030, Attachment 1 – Annual revenue requirement*, September 2024, p. 9.
[93] The price impacts factor in transmission charges from Powerlink that are forecast to increase by inflation and the Queensland Government's Solar Bonus Scheme expiring on 1 July 2028. For forecast inflation, we have used a forecast of 2.85 per cent based on the AER's methodology set out in the PTRM.

Table 40: Revised indicative bill impacts

$, nominal	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	Average Annual change
Residential[1]							
Indicative annual bill	$1,005	$1,081	$1,141	$1,198	$1,233	$1,279	
Annual ($) change		$76	$60	$57	$34	$46	$55
Annual (%) change		7.6%	5.6%	5.0%	2.9%	3.8%	5.0%
Small business[2]							
Indicative annual bill	$1,942	$2,211	$2,321	$2,414	$2,518	$2,575	
Annual ($) change		$269	$110	$93	$104	$58	$127
Annual (%) change		13.9%	5.0%	4.0%	4.3%	2.3%	5.9%
Large low voltage business[3]							
Indicative annual bill	$58,317	$61,872	$66,380	$70,480	$76,414	$78,434	
Annual ($) change		$3,555	$4,507	$4,100	$5,934	$2,020	$4,023
Annual (%) change		6.1%	7.3%	6.2%	8.4%	2.6%	6.1%

Notes:
1. Residential typical customer: calculated as a weighted average of the bill impact on the residential inclining block tariffs and transitional demand tariffs at the total network level assuming annual energy usage of 5024kWh and monthly demand of 3.48kW.
2. Small business customer: customer on the default transitional demand tariff with annual consumption of 14,485kWh with a monthly peak demand of 7.41kW.
3. Large low voltage business typical customer: Customer on Demand Small Tariff with annual consumption of 380,917 and with a monthly anytime demand of 59.76kVA.

8.11 Supporting documentation

The following documents support this chapter:

Document Name	Reference	File name
SCS AER RFM Model	8.01	Ergon - 8.01 - Model SCS AER RFM - November 2024 - public
SCS AER Depreciation Model	8.02	Ergon - 8.02 - Model SCS AER Depreciation - November 2024 - public
SCS AER PTRM Model	8.03	Ergon - 8.03 - Model SCS AER PTRM - November 2024 - public

9.
Network Tariffs and Pricing

Key messages:

- The AER's Draft Decision did not approve our initial 2025-30 TSS.
- We have reflected most elements of the AER's Draft Decision in our revised TSS, including changing the default tariff for residential and small business customers from a TOU demand to a TOU energy tariff and introducing a new optional TOU energy tariff for large low voltage business customers.
- The AER's Draft Decision has also resulted in Ergon Energy Network modifying our position on transitioning customers to two-way tariffs and storage tariffs.
- Our revised TSS includes additional information required by the AER in order to make it capable of acceptance.

9.1 Overview of the AER's Draft Decision

A customer's most regular interaction with the energy supply chain is usually through the payment of their energy bill to a retailer. A retailer's bill includes all costs associated with providing energy to the home or business, which includes Ergon Energy Network's costs. We recover our costs classified as SCS through our network tariffs. The network tariff is a combination of charges applied to each customer representing their contribution to the costs of distributing electricity. We bill retailers based on usage and the network tariff to which a customer has been assigned.

In January 2024, we submitted our proposed network tariff structures and assignment arrangements to the AER in our 2025-30 TSS and TSES. Both documents provided information about our network tariffs and compliance with the NER, with the TSES providing additional information on the drivers of change and how our customers' preferences and input were incorporated into our proposal.

The AER's Draft Decision was to not approve our proposed 2025-30 TSS. The AER was not satisfied that all elements of the proposed TSS comply with the pricing principles and other applicable requirements of the NER and does not contribute to achievement of the National Electricity Objective. Elements of our proposed 2025-30 TSS which were not approved by the AER include:

- tariff assignment for residential and small business customers
- proposed two-way tariffs
- tariff assignment for large low voltage business customers
- proposed flexible load control tariffs, and
- grid-scale storage tariffs.[94]

The AER was satisfied that many elements of our proposed 2025-30 TSS comply with the pricing principles and accepted the following in its Draft Decision:

- tariff structures for residential and small business customers, not including two-way tariffs or the proposed new optional flexible load control tariffs

[94] AER, *Draft Decision, Ergon Energy and Energex Electricity Distribution Determination 2025-2030, Attachment 19 – Tariff structure statement,* September 2024, p. 4-5.

- tariff structures for large low voltage and high voltage business customers, not including two-way tariffs
- tariff assignment for high voltage business customers
- continuation of existing primary and secondary load control tariffs
- tariff streamlining and withdrawal of obsolete or closed tariffs, and
- our approach to setting and assigning customers to ICC tariffs.[95]

We are not proposing any changes to these aspects of our initial proposal in our revised TSS.

9.2 Our response to the AER's Draft Decision

Our revised TSES (Attachment TSS-02) provides information on how we have responded to the AER's feedback and our revised 2025-30 TSS (Attachment TSS-01) demonstrates how our proposed network tariffs for the 2025-30 regulatory control period comply with the requirements of the NER and the AER's *Export Tariff Guidelines*.

Our revised TSS includes amendments reflecting the AER's Draft Decision in order for the TSS to be approved. Exceptions relate to AER decisions that were not consistent with our own customer feedback or operational implementation capability. In these instances, we have made alternative changes in response to the AER's decision. Examples include assignment arrangements for residential and small business customers, two-way tariffs and dynamic storage tariffs.

We have also responded to the AER's request for additional information to be included in documentation, including in the areas of customer bill impact, dynamic connections, flexible load tariffs and tariff streamlining. Table 41 sets out the elements of our TSS which were not approved by the AER, how we have responded to the AER's feedback and where to find more information.

Table 41: How we have responded to AER's Draft Decision on network tariffs

Issue in Draft Decision	Change requested by the AER	Our response
Tariff assignment for residential and small business customers	Change default assignment for residential and small business customers with smart meters from the TOU demand and energy tariffs to TOU energy tariffs. Reassign existing customers from current default transitional demand tariffs to TOU energy tariffs.	Assignment arrangements are amended in our revised TSS in response to the AER's Draft Decision. New and upgrading residential and small business customers will be assigned to TOU energy tariffs. Retailer-led meter upgrades will result in an assignment to TOU energy tariffs 12 months after the financial year in which the upgrade occurred. The TOU demand and energy tariffs will remain as optional tariffs. TOU energy tariffs will not be assigned retrospectively to customers on the current default tariff. These customers will remain on their current default tariff but retain the option to access TOU energy tariffs during the 2025-30 period if they choose.

[95] Ibid, p. 4.

Issue in Draft Decision	Change requested by the AER	Our response
Contingent tariff adjustments	Include further information on contingent tariff adjustments to remove obsolete tariffs within the 2025-30 period.	In response to the AER's Draft Decision and customer feedback we will remove the contingent tariff adjustment from our revised TSS. Instead, we will withdraw the legacy small business Wide Inclining Fixed tariff from 1 July 2025. We expect this change will increase transparency for basic meter customers and ultimately assist with the transition to a more cost-reflective tariff.
Two-way tariffs	Include an explicit export tariff transition strategy. Convert export charges and basic export level from kW to kWh. Include network bill impact analysis for small businesses and large customers to face two-way tariffs.	Our Initial TSS introduced two-way tariffs, commencing for new customers from 1 July 2026 and transitioning to all customers from 1 July 2028. In response to customer feedback, customers opting in to a dynamic connection would be able to opt-out of two-way tariffs. The AER rejected our tariff structures for two-way tariffs and requested additional changes and more information be provided in the revised TSS in order for it to be capable of acceptance. Our revised TSS does not make these changes but instead extends the introduction of two-way tariffs to beyond the 2025-30 regulatory control period.
Tariff assignment for SAC Large business customers	Offer TOU energy tariffs for SAC Large customers with demand greater than 120 KVA and consumption less than 160 MWh per annum.	In response to the AER's Draft Decision we have introduced a new optional TOU energy tariff for SAC Large customers with demand greater than 120 KVA and consumption less than 160 MWh per annum from 1 July 2025.
Flexible load control tariffs	Include further description of control arrangements that are contained in the QECM, including the relationship between the QECM and TSS, and the extent to which control arrangements influence tariff options, including the new flexible load tariffs.	Our revised TSS includes further information on the new residential and small business flexible load tariffs. Additional information regarding the QECM is also included.
Grid-scale storage tariffs	Provide further detail on grid-scale storage tariffs, including more detail on the critical peak pricing mechanism.	Our initial TSS proposal was to include two grid-scale storage tariff structure options: the dynamic price storage tariff and dynamic flex storage tariff. The dynamic flex storage tariff (with no critical peak prices) will be offered as an optional tariff from 1 July 2025. We consider this simplified tariff structure proposal compliant with the NER and capable of understanding by customers and retailers.

Issue in Draft Decision	Change requested by the AER	Our response
		The dynamic price storage tariff incorporating critical peak period import and export charge components will be offered as a trial tariff from 1 July 2025. In addition, a complementary secondary tariff incorporating critical peak period import and export reward components will be trialled from 1 July 2025. The secondary tariff will be made available to customers on both the dynamic flex and dynamic price storage tariffs.

9.3 Other changes since our initial TSS

9.3.1 Delayed introduction of two-way tariffs

Our initial TSS introduced two-way tariffs, commencing for new customers from 1 July 2026 and transitioning to all customers from 1 July 2028.

However, since submitting our initial TSS and publication of the AER's Draft Decision, Ergon Energy Network has decided to propose a delay in the introduction of two-way tariffs to the next regulatory control period. In our view, the benefits of introducing export pricing at this stage are likely to be limited and outweighed by the costs associated with its implementation. Further analysis suggests that it is unlikely that the quantum of export charges will be sufficient to result in any meaningful change in customer behaviour and it is uncertain whether they would be incorporated into retail offers. Therefore, the transaction costs associated with implementing export prices for both networks and retailers are unlikely to be offset by export tariff uptake. Consequently, Ergon Energy Network will focus on a demand-side solution through TOU pricing to encourage a shift in customer behaviour, before implementing two-way tariffs in the future.

Our two-way pricing transition strategy was built on cautious support for two-way tariffs, with concerns that more time was needed to adjust to this change. Customers were of the view that the transition to two-way pricing should not occur until other reforms have been embedded first and is supported by increased education for customers.

There are also considerable uncertainties in the build-up of policy reform in line with a greater penetration of smart meters. Smart meter customers have only recently started to see more cost-reflective tariffs and price signals. Customers have expressed frustration in the way some retailers have passed through network tariffs and retailers have highlighted the significant challenges in explaining these changes to end-use customers.

Delaying the introduction of two-way pricing will allow other policy frameworks to be embedded and provide more time for Ergon Energy Network to deliver better information to customers on how the two-way tariffs would work and how such a tariff would impact them if introduced.

9.3.2 Further streamlining of tariff prices and structures

The AER's Draft Decision reflects submissions noting the complexity around the number and structure of our network tariffs.

However, it should be noted that Ergon Energy Network has additional complications in that it is split into three separate distribution pricing zones, and until recently, additional transmission pricing regions. Further, the Queensland Government applies special pricing arrangements for Ergon Energy Network customers, aimed at ensuring most customers in regional Queensland face lower electricity bills relative to the cost of supply. This impacts how our network tariffs are passed through to the end-use customer.

For residential and small business customers in the East Pricing Zone and for large low voltage customers in the West and Mount Isa Zones, the separate network prices and structures bear little resemblance to the retail bill which is governed by a Notified Pricing arrangement administered by the Queensland Competition Authority (QCA) under direction from the Queensland Government. Notified retail prices for residential and small business customers in Ergon Energy Network's area are based on the cost of supply in South East Queensland. For large low voltage customers, notified prices are based on the Ergon Energy Network pricing region with the lowest cost of supply (region East).

The AER's Draft Decision was supportive of Ergon Energy Network's efforts to streamline tariffs and structures where possible. To deliver more simplicity into our tariff arrangements and indicative prices, we have sought to rebalance revenues across the different charges to align variable charges (volume and demand charges) to South East Queensland prices for residential and small business customers (or region East prices for large low voltage customers) where possible.

To ensure the forecast quantities multiplied by the indicative distribution prices remain equal to the approved revenue for Ergon Energy Network, we will modify the fixed charges as required. This will ensure the relative revenue contribution from each pricing region and each individual tariff remains unchanged (i.e. the residual difference in revenue will be reflected in the fixed charges). This approach not only provides customers on QCA-notified prices with more transparency on the basis on which their retail bill is set, but it also provides information on the effective differential between the notified prices and what may be provided in an open market on a dollar per customer per day basis.

Our analysis suggests the vast majority of Ergon Energy Network's residential and small business customers are on notified pricing arrangements and this change should not impact their end-use bill.

9.4 Ongoing customer engagement

We commenced our tariff engagement in 2021, to develop the initial approaches towards refining network tariffs, customer impact framework and customer education. Since submission of our initial TSS, we have continued to engage with residential and business customers and other stakeholders on our tariffs and indicative prices.

We engaged with our VOC Panel to discuss indicative prices for residential customers in the context of affordability. The Panel had mixed views on the pace of change around tariff reform, particularly with respect to the introduction of two-way pricing and noted the need for further customer education. The export tariff transition strategy set out in our TSS therefore outlines our decision to suspend implementation of two-way tariffs until the next regulatory control period.

In recognition of the value and contribution that the NPWG brought to the development and review of our network tariff strategy, we took the opportunity to transition the NPWG to a representative forum that would assist us in the finalisation of our 2025-30 TSS. An open expression of interest process resulted in an expansion of the NPWG membership with broadened representation. Membership now covers both Queensland networks, with representation from large and small businesses, the retail sector and representatives from different cohorts of residential customers.

The NPWG met five times between February and October 2024. The NPWG's focus has been on providing input and consensus positions on issues raised either through the AER's Issues Paper, stakeholder responses, or the Draft Decision. The NPWG explored the following network tariff-related topics and issues in depth:

- load control tariffs and the QECM
- dynamic connections and two-way tariffs
- storage tariffs and the level of fixed charges
- TOU energy tariffs for customers consuming 100-160 MWh per annum, and
- demand tariffs and their appropriateness as the default tariffs for residential customers.

The NPWG's feedback on these issues is provided in our TSES.

We also continued to engage with large customers primarily through individual one-on-one discussions. These discussions were intended to enable large customers to explore their specific issues of concern and indicative network prices. Our large customers continue to tell us that cost of electricity is a key consideration in their business investment decision-making.

9.5 Supporting documentation

The following documents support this chapter:

Document Name	Reference	File name
2025-30 Indicative Network Prices	9.01	Ergon - 9.01 - 2025-30 Indicative Network Prices - public
Endgame Economics – LRMC model	9.02	Ergon - 9.02 - Endgame Economics - LRMC model - public
Stand alone and Avoidable Model	9.03	Ergon - 9.03 - Stand alone and Avoidable Model - November 2024 - public

10.
Metering

Key messages:

- The AER's Draft Decision accepted most of our metering services proposal, including the reclassification of legacy metering services as SCS and the application of a revenue cap.
- The AER provided a substitute forecast for metering opex due to updated inputs, which resulted in a substitute annual revenue requirement.
- Due to the uncertainty of legacy metering replacement volumes, the AER's Draft Decision also provided for a true-up mechanism for opex.
- We accept the AER's Draft Decision with respect to metering.

10.1 Overview of the AER's Draft Decision

Metering services are activities relating to the measurement of electricity supplied to and from customers through the distribution system. This includes meter reading, meter testing and maintenance, meter investigations and meter data services. The Power of Choice reforms fundamentally changed our role in the provision of metering services, reducing it to managing and maintaining our remaining Type 6 basic accumulation meters ("legacy meters") as they are progressively phased out and replaced by Type 4 smart (digital) meters.

What we proposed and the AER's Draft Decision on metering is summarised in Table 42.

Table 42: Summary of the AER's Draft Decision on metering[96]

Category	Regulatory Proposal	Draft Decision
Service classification	Reclassify legacy metering services from ACS to SCS and application of a revenue cap form of control.	Accepted.
Treatment of Mount Isa-Cloncurry network	Metering services for the Mount Isa-Cloncurry network be treated the same as the grid-connected network (i.e. also be classified as SCS).	Accepted.
Acceleration of depreciation	Accelerate the recovery of legacy meter depreciation to achieve full recovery by the end of the 2025-30 regulatory control period.	Accepted.
Metering revenue components	No new capex, standard revenue components applied such as return on existing capital, depreciation, opex and tax allowance.	Reduced opex resulting in a lower revenue.
Metering charges	Recover costs through a flat per customer charge to low voltage customers, regardless of customer, tariff, or meter type.	Accepted.
True-up mechanism for opex	N/A	Introduction of a true-up mechanism for opex to account for uncertainty of legacy metering replacement volumes.

[96] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Attachment 20 – Metering services*, September 2024, pp. 4, 15.

10.2 Our response to the AER's Draft Decision

We accept the AER's Draft Decision for metering, including the addition of a true-up mechanism for opex. As requested by the AER, we have provided an amended bottom-up opex model with our Revised Regulatory Proposal to allow for the outworking of the true-up mechanism (refer to Attachment 10.01).

Based on the latest information available, inputs have been updated consistent with other aspects of our Revised Regulatory Proposal. Our metering revenue forecast is now $170.7 million for the 2025-30 regulatory control period. This is 0.1 per cent lower than the AER's Draft Decision. Our response to the AER's Draft Decision on our forecast metering revenue, and our updated revenue building blocks, is summarised in Table 43. The annual metering services charges to be recovered from all low voltage customers over the 2025-30 regulatory control period is shown in Table 44.

Table 43: Summary of our response to AER's Draft Decision on metering revenue

$m, nominal	Regulatory Proposal	Draft Decision	Difference to Regulatory Proposal	Summary of our response	Revised Regulatory Proposal	Difference to Regulatory Proposal
Return on capital	8.1	8.0	-0.1	Modify[1]	7.8	-0.3
Regulatory depreciation	42.2	42.0	-0.2	Accept	42.0	0.0
Opex	128.9	120.0	-8.9	Accept	120.0	-8.9
Tax allowance	0.0	0.0	0.0	Accept	0.0	0.0
Annual revenue requirement (unsmoothed)	179.2	170.0	-9.2	Modify	169.8	-9.4
Smoothed revenue	179.7	170.9	-8.9%	Modify	170.7	-9.0
X factors[2]	-0.2%	4.5%		Modify	4.6%	

Note 1: Modify classification as revisions made to calculation inputs
Note 2: Negative X factor implies an increase in revenue

Table 44: Forecast metering services annual charges ($, nominal)

$m, nominal	2025-26	2026-27	2027-28	2028-29	2029-30
Annual Metering Charge ($/year)	41.83	42.66	43.51	44.38	45.27

10.3 Supporting documentation

The following documents support this chapter:

Document Name	Reference	File name
Metering Opex Model 2025-30	10.01	Ergon - 10.01 - Metering Opex Model 2025-30 - November 2024 - public
Metering RFM 2025-30	10.02	Ergon - 10.02 - Metering RFM 2025-30 - November 2024 - public
Metering PTRM 2025-30	10.03	Ergon - 10.03 - Metering PTRM 2025-30 - November 2024 - public
Metering Pricing Model 2025-30	10.04	Ergon - 10.04 - Metering Pricing Model 2025-30 - November 2024 - public

11.
Alternative Control Services

Key messages:

- The AER found that the proposals for ACS were largely reasonable and only made minor substitutions for some pricing inputs.
- The AER accepted our proposal to reclassify legacy metering services from ACS to SCS but did not accept our proposal to reclassify supply abolishment services from ACS to SCS.
- We largely accept the AER's Draft Decision, except for the decisions relating to quoted services labour rates and reclassification of supply abolishment services.

11.1 Overview of the AER's Draft Decision

ACS are distribution services that are customer-specific or customer-requested services and are paid for by the customer who seeks the service. In line with the AER's Final F&A for the 2025-30 regulatory control period, the following services or service groups are classified as ACS:

- public lighting (including security lighting)
- connection management services
- enhanced connection services, and
- ancillary services (quoted and fee-based services).

What we proposed and the AER's Draft Decision on ACS is summarised in Table 45.

Table 45: Summary of the AER's Draft Decision on ACS

ACS Category	Regulatory Proposal	Draft Decision
Public lighting	A Public Lighting Strategy, which included: • achieve 100 per cent deployment of LED public lights • fund the upfront capital cost of the conversion of Rate 1 and Rate 2 conventional assets to LED • extend the cost recovery timeframe out to 2035 for the residual value of the remaining conventional lights • introduce a user-pays approach for smart control devices, and • forecast public lighting expenditure, revenue and pricing for 2025-30.	Accepted strategy and made minor amendments to expenditure, revenue and pricing.

ACS Category	Regulatory Proposal	Draft Decision
Ancillary Services	For fee-based ancillary services: • changes to service dimensions, such as travel time, time to complete a job and number of crew required • rationalise our suite of services by discontinuing the service permutations which have had little to no uptake over the past three years, and • draft prices. For quoted ancillary services: • labour rates specific to the quoted service to improve cost-recovery, and • apply a margin to promote competitive neutrality.	For fee-based ancillary services: • maintained price cap form of control with labour price escalation as X factor. • accepted all changes to service offerings and assumptions • accepted all labour category rates excluding the administrative category, and • accepted all service prices with revised escalation excluding property search fees. For quoted ancillary services: • applied the lower of maximum efficient benchmarked labour rates or proposed labour rates.
Security Lighting	Cease to provide and install new security lights for new customers but continue to maintain and operate security lights for existing customers until they transition to alternative solutions.	Accepted pricing approach for security lighting.
Reclassification of Legacy Metering Services	Reclassify legacy metering services from ACS to SCS to reduce the disproportionate cost burden on customers who will be the last to receive a smart meter, including vulnerable customers.	Accepted.
Reclassification of Supply Abolishment Services	Reclassify the removal of connection assets (or “supply abolishment”) from ACS to SCS due to public safety concerns.	Not accepted as work is driven by a single customer, not a shared network service and other DNSPs have it classified as ACS.

11.2 Our response to the AER’s Draft Decision

We largely accept the AER’s Draft Decision, with proposed exceptions set out in the sections below.

11.3 Public lighting

The public lighting services provided by Ergon Energy Network include the provision, maintenance, and operation of public lighting assets. In developing our Regulatory Proposal, we collaborated extensively with our customers. Following this broad consultation process and with customer endorsement, we proposed to convert all conventional lights to LED technology by 2030. The strategy included the initiative to recover the residual value of the remaining conventional lights out to 2035, both to support the full deployment of LEDs during this transition period as well as to mitigate customer impact. We are pleased that the AER supports our proposed roll-out of LED public lighting and proposed public lighting strategy.

In our submission we also indicated to customers that we would pursue a public lighting engagement plan which pivots from a Regulatory Proposal development project activity to a business-as-usual implementation phase post 1 July 2025. As foreshadowed, in October 2024 we held an engagement session that focused on informing customers about:

- the outcomes of the AER's Draft Decision
- the proposed process and participation in a pilot of the upcoming Smart Lighting System, and
- the outcomes of the AEMC's Final Determination on *Unlocking CER benefits through flexible trading* rule change.[97]

Ergon Energy Network is committed to continual engagement with our customers, stakeholders, and their representatives to enable the successful deployment of our endorsed public lighting strategy.

While the AER's Draft Decision considered our public lighting proposal to be reasonable, it amended labour escalators, WACC and inflation to be consistent with draft decisions on other relevant aspects of our Regulatory Proposal.[98]

We updated the modelling for our Revised Regulatory Proposal by applying the most recent WACC and labour rates, and by updating actuals for 2023-24. In doing this update, we identified that the modelling submitted with the Regulatory Proposal and used in the AER's Draft Decision had not been updated to incorporate 2022-23 actual capex and was instead based on forecast capex for the year. Actual 2022-23 capex significantly exceeded the forecast capex for the year due to the acceleration of the conversion of mercury vapour lights to LEDs. The high level of actual spend continued into 2023-24. This higher than forecast spend has increased the projected opening Public Lighting Asset Base and consequently impacted forward prices. However, this increase was offset by applying the revised WACC and labour rates, which had a downward impact on forecast public lighting revenue. The outcome of these modelling updates and corrections is that the average price impact for customers is an initial estimated increase of 21 per cent for the 2025-26 year with prices remaining flat for the remaining four years of the 2025-30 regulatory control period.[99]

Our response to the AER's Draft Decision is summarised in Table 46. Attachment 11.03 provides our updated opex, capex and revenue for public lighting and Attachment 11.06 provides the revised prices.

[97] AEMC, *Unlocking CER benefits through flexible trading, Rule determination*, 15 August 2024, available on the [AEMC's website](#).

[98] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Attachment 16 – Alternative control services*, September 2024, p. 23.

[99] The average customer impact reflects the impact of the replacement of all the Rate 1 and Rate 2 conventional lights to LED, and the reassignment of the Rate 4 assets to Rate 2 LED tariffs.

Table 46: How we have responded to AER's Draft Decision on public lighting

Issue in Draft Decision	Our response	More information
The AER amended labour escalators to be consistent with the SCS opex draft decision	For the Revised Regulatory Proposal, Ergon Energy Network has applied labour escalators consistent with those used in the calculation of SCS opex.	Attachment 11.01.
The AER updated the WACC used to determine public lighting charges to be consistent with its Draft Decision on rate of return	Ergon Energy Network has applied the same WACC value to determine public lighting charges for the Revised Regulatory Proposal as is used to derive SCS revenue.	Attachment 11.03.
The AER has substituted inflation inputs with placeholder values that will be updated in the Final Decision	Ergon Energy Network has applied the AER's estimate of inflation from the Draft Decision to calculate public lighting charges for the Revised Regulatory Proposal. We note that this is a placeholder value that will be updated by the AER for the Final Decision.	Attachment 11.03.
The AER is open to Ergon Energy Network introducing pricing for new public lighting services, provided it conforms to the control mechanism for quoted services[100]	Ergon Energy Network is not proposing to introduce any new services in this Revised Regulatory Proposal. Ergon Energy Network will treat any new services implemented at the request of a customer during the next regulatory control period as a quoted service.	N/A

11.4 Ancillary services

Ancillary services are non-routine services provided to individual customers as requested, for example, temporary disconnections and reconnections, supply abolishment and meter testing. These services do not form part of the suite of common distribution services in recognition of the fact that not all customers request or require them.

Our Regulatory Proposal included 187 individual ancillary network services that are either fee-based or quoted services provided to individual customers. These services are subject to an AER price cap. Fee-based services are homogeneous services provided on request for the benefit of a single customer, rather than a service supplied to customers collectively. The prices for fee-based services are determined using a cost build up approach based on the labour rates, vehicle costs, and overheads that are anticipated to apply in the delivery of the services over the 2025-30 regulatory control period. Quoted services are services that vary in nature, and the scope of the work is specific to the individual customer's requirements. The price for quoted services will reflect the approved rates at the time the work is requested.

[100] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Attachment 16 – Alternative control services*, September 2024, p.23.

For the 2025-30 regulatory control period, we proposed rates for six labour categories for fee-based services and nine labour categories for quoted services, reflecting the different types of labour resources required for the provision of ancillary network services. We also proposed the following changes to fee-based services compared to the current period:

- **Service consolidation –** the amalgamation of the Urban/Short Rural with the Long Rural/Isolated feeder type and discontinuation of services which had limited uptake in the prior three years, resulting in a reduction in 172 service offering permutations
- **Health and safety requirements –** increase to crew size from one to two crew members for high-risk services
- **Updated contractor rates** – extended current procurement contracts with higher rates due to shortage of reputable and qualified service providers, and
- **Updated travel time** – an average of 23 minutes to travel to site for the period 2025-30.

The AER's Draft Decision did not accept our proposal as submitted. The AER adjusted the proposed 2025-26 prices with Draft Decision price caps that reflect its Draft Decision on CPI and X factors.[101]

As a result of benchmarking, the AER did not accept the following labour rates and instead replaced them with an alternative efficient labour rate:

- Administrative (business hours)
- Quoted Services Administrative (business and after hours)
- Quoted Services Professional and Managerial (business hours), and
- Quoted Services System Operator (business hours).[102]

The AER did accept the proposed changes to service inputs for travel time, contractor costs and crew size for high-risk services.[103]

We accept the AER's Draft Decision on fee-based ancillary network services in full. However, although the majority of our proposed quoted services labour rates were accepted on the basis that they were below the AER's benchmark maximum labour rate, we have revised all quoted service labour category rates. The update to labour category rates is to reflect 2023-24 costings resulting from changes to wages and employment conditions under our Enterprise Bargaining Agreement and other general employment conditions, which were not reflected in the original proposed based rates. This has increased the average quoted service base labour rates by 15 per cent relative to the Draft Decision. Our full price list for ancillary network services is provided in Attachment 11.07.

Table 47 outlines our response to the AER's Draft Decision on ancillary network services.

---

[101] Ibid, p. 7.

[102] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Attachment 16 – Alternative control services*, September 2024, p. 10.

[103] Ibid, pp. 12-13.

Table 47: How we have responded to AER's Draft Decision on ancillary services

Issue in Draft Decision	Our response	More information
Price caps for fee-based services	Accept prices and X factors as set out in the AER's Draft Decision Ancillary Services Model.	Attachment 11.07.
Labour rates for quoted Services	Updated Rates to reflect 2023-24 costing.	Attachment 11.07.

11.5 Security lighting

Security lighting services generally involve installation, operation, maintenance and replacement of lighting equipment which is typically mounted to our distribution network poles and structures.

Our Regulatory Proposal reconfirmed our view, as stated in our submission to the AER's F&A process, that new security lighting installations will no longer be offered from 1 July 2025. We also proposed to set prices for 2025-26 by escalating current prices using the CPI-X approach consistent with the price cap form of control.

The AER considered the proposed changes and pricing approach to security lighting services to be reasonable.[104]

We accept the AER's Draft Decision on security lighting services in full. The proposed security lighting tariffs for the 2025-30 regulatory control period are provided in Attachment 11.06.

11.6 Service reclassification for supply abolishment services

The AER's Draft Decision did not accept a request by Ergon Energy Network to reclassify the removal of connection assets (or "supply abolishment") from ACS to SCS. This decision was based on the following reasons:

- supply abolishments are driven by a single customer, and
- other DNSPs offer the service as an ACS.[105]

However, Ergon Energy Network remains of the view that there is a case to change the service classification for simple supply abolishments to SCS, primarily for public safety reasons and to align with similar classification decisions that apply to distributors in Victoria and Tasmania.[106]

This matter is discussed in Chapter 12, section 12.2.1.

[104] Ibid, p. 14.
[105] Ibid. pp. 13-14.
[106] AER, *Final framework and approach: AusNet Services, CitiPower, Jemena, Powercor and United Energy, Regulatory control period commencing 1 January 2021*, January 2019, and AER, *Framework and approach: TasNetworks distribution and transmission (Tasmania), Regulatory control period commencing 1 July 2024*, July 2022.

11.7 Supporting documentation

The following documents support this chapter:

Document Name	Reference	File name
Public Lighting Capex and Opex Forecasting Model	11.01	Ergon - 11.01 - Public Lighting Capex and Opex Forecasting Model - November 2024 - public
Public Lighting RFM	11.02	Ergon - 11.02 - Public Lighting RFM - November 2024 - public
Public Lighting PTRM	11.03	Ergon - 11.03 - Public Lighting PTRM - November 2024 - public
Public Lighting PTRM to Pricing Intermediary Model	11.04	Ergon - 11.04 - Public Lighting PTRM to Pricing Intermediary Model - November 2024 - public
Public Lighting Pricing Model 2025-30	11.05	Ergon - 11.05 - Public Lighting Pricing Model 2025-30 - November 2024 - public
ACS Price Schedule 2025-30	11.06	Ergon - 11.06 - ACS Price Schedule 2025-30 - November 2024 - public
ACS Ancillary Services Model 2025-30	11.07	Ergon - 11.07 - ACS Ancillary Services Model 2025-30 - November 2024 - public

12.
Other Regulatory Matters

Key messages:

- Ergon Energy Network accepts the AER's Draft Decision on control mechanisms, negotiating framework, nominated pass through events, contingent projects and connection policy.
- We largely accept the AER's Draft Decision on classification of services, with the exception of the decision to not accept the proposed reclassification of supply abolishment services from SCS to ACS.
- We consider that an amendment to the F&A to mitigate the significant community safety risks associated with failure to abolish supply, and to align with other jurisdictions' classifications, warrants further consideration by the AER.
- We have addressed the requirements of the AER's *Confidentiality Guideline* as to the matters for which we are claiming confidentiality.

12.1 Overview of the AER's Draft Decision

Ergon Energy Network's Regulatory Proposal set out our proposed approach to a number of regulatory matters, including classification of services, control mechanisms, negotiating framework, nominated pass through events, contingent projects and connection policy. The AER's Draft Decision on these key matters is summarised in Table 48.

Table 48: Summary of AER's Draft Decision on Key Regulatory Matters

Matter	Regulatory Proposal	Draft Decision
Classification of services	Ergon Energy Network broadly supported the AER's proposed service classifications as set out in the Final F&A. However, we proposed that legacy metering services should be reclassified as SCS. We also subsequently proposed that supply abolishment services should be reclassified from ACS to SCS.	The AER's Draft Decision is to maintain the service classifications set out in the Final F&A, except for legacy metering services which will be reclassified as SCS, and the inclusion of data services as a common distribution service. The AER did not accept our proposal to reclassify supply abolishment services from ACS to SCS.
Control mechanisms	Ergon Energy Network accepted the AER's control mechanism decision as set out in the Final F&A, namely: • revenue cap for SCS, and • price cap for ACS. We proposed a departure from the control formulae for SCS provided in the Final F&A.	The AER's Draft Decision for Ergon Energy Network on the form of control mechanism for SCS is a revenue cap, which now includes legacy metering services. The AER has adopted the revised SCS control formulae and separate metering-specific parameter definitions to separate legacy metering revenue from the main SCS. The form of control mechanism for ACS is a price cap. The Draft Decision includes the price cap formulae for fee-based ancillary services, public lighting services and quoted ancillary network services.
Negotiating framework	Ergon Energy Network's proposed negotiating framework for the 2025-30 regulatory control period was submitted with the Regulatory Proposal for approval.	The AER's Draft Decision is that the proposed negotiating framework submitted by Ergon Energy Network will apply for the 2025-30 regulatory control period.

Matter	Regulatory Proposal	Draft Decision
Pass through events	Ergon Energy Network nominated the following additional pass through events: • insurance coverage event • insurer's credit risk event • terrorism event, and • natural disaster event.	The AER's Draft Decision is to accept Ergon Energy Network's nominated pass through events consistent with the Regulatory Proposal, subject to minor amendments to the proposed definition for the insurance coverage event.
Contingent projects	Ergon Energy Network did not propose any contingent projects.	As Ergon Energy Network did not propose any contingent projects for the 2025-30 regulatory control period, the AER did not make a decision under clause 6.12.1(4A) of the NER.
Connection policy	Ergon Energy Network's proposed connection policy for the 2025-30 regulatory control period was submitted with the Regulatory Proposal for approval.	The AER's Draft Decision is to approve the connection policy proposed by Ergon Energy Network.

12.2 Our response to the AER's Draft Decision

Ergon Energy Network appreciates the AER's consideration of the matters raised in our Regulatory Proposal and largely accepts the AER's Draft Decision in this Revised Regulatory Proposal. Our response to the AER's Draft Decision is discussed further below.

12.3 Classification of services

Service classification determines which of our distribution services will be regulated by the AER and how the costs of the regulated services will be recovered from customers.

The AER's Draft Decision proposes to maintain the service classifications set out in the Final F&A, with the following exceptions:

- reclassifying legacy metering services from ACS to SCS, and
- including data services as a common distribution service.[107]

However, the AER did not accept Ergon Energy Network's proposal to reclassify supply abolishment services from ACS to SCS.[108]

Ergon Energy Network's Revised Regulatory Proposal accepts the AER's Draft Decision, with the exception of the determination that supply abolishment services should remain classified as ACS, for reasons outlined below.

12.3.1 Classification of supply abolishment services

The AER's Draft Decision did not accept a request by Ergon Energy Network to reclassify the removal of connection assets (or "supply abolishment") from ACS to SCS. This decision was based on the following reasons:

- supply abolishments are driven by a single customer, and
- other DNSPs offer the service as an ACS.[109]

[107] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Attachment 13 – Classification of Services*, September 2024, p. 1.
[108] Ibid. p. 5.
[109] Ibid. pp. 5 and 9.

However, Ergon Energy Network remains of the view that there is a case to change the service classification for simple supply abolishments to SCS, primarily for public safety reasons and to align with similar classification decisions that apply to distributors in Victoria and Tasmania.[110]

Ergon Energy Network accepts that, in principle, a supply abolishment is driven by a specific customer and the costs can be attributed to the customer to whom the service is provided. This reasoning is consistent with the current F&A for the 2020-25 regulatory control period which classifies this service as ACS under the connection application and management service group. However, notwithstanding the current ACS classification, Ergon Energy Network has identified that, in practice, there has been an increase in the number of instances where customers attempt to circumvent the fee by closing their electricity account and vacating the premises without requesting a supply abolishment. In a growing number of these instances, failure to carry out supply abolishment works is resulting in safety risks at building demolition, removal or relocation sites and urgent action is required by Ergon Energy Network to make the premises safe.

To provide further clarity, Ergon Energy Network's proposal is to reclassify simple supply abolishment (i.e. for small customer connections) as a standard control common distribution service. This reclassification would remove any disincentive to initiate a supply abolishment due to reluctance to incur an ACS fee and thus prevent consequent safety hazards. We propose, however, that more complex supply abolishment (i.e. for large customer connections) should remain classified as ACS under the connection application and management service group (i.e. the current "removal or repositioning of connection assets" service). Refer to Attachment 12.01.

We acknowledge that this proposed change in classification would result in supply abolishment-related costs for small customer connections being recovered from all customers through network charges rather than from an individual customer. However, we consider this activity is consistent with other activities concerned with providing a safe and reliable electricity supply to customers and that the benefits of mitigating public safety risks outweighs a "user-pays" approach.

Further, Ergon Energy Network's proposal is consistent with the classification decisions that have been applied to distributors in Victoria and Tasmania for similar supply abolishment services. For example, the AER's Final F&A for TasNetworks for the 2024-29 regulatory control period provided the following reasoning for accepting the request for a classification change from ACS to SCS for supply abolishment of a basic connection:

> "We accept TasNetworks submission regarding the public safety risks associated with energised service conductors in abandoned buildings. When we classified a similar supply abolishment service for Victorian distributors, we recognised that on leaving premises the departing party may have a strong incentive to avoid paying the full costs of abolishment. Although the service applies to individual customers, and warrants an alternative control classification, we nevertheless recognise the significant public safety hazard and accept TasNetworks' request."[111]

Accordingly, Ergon Energy Network considers that an amendment to the F&A to mitigate the significant community safety risks associated with failure to abolish supply, and to align with other jurisdictions' classifications, warrants further consideration by the AER.

[110] AER, *Final framework and approach: AusNet Services, CitiPower, Jemena, Powercor and United Energy, Regulatory control period commencing 1 January 2021*, January 2019, and AER, *Framework and approach: TasNetworks distribution and transmission (Tasmania), Regulatory control period commencing 1 July 2024*, July 2022.

[111] AER, *Final framework and approach for TasNetworks for the regulatory control period commencing 1 July 2024*, July 2022, p. 28.

12.4 Control mechanisms

The NER specify that a distribution determination must impose controls over the prices of direct control services, revenue to be derived from the direct control services, or both.[112] The NER also specify that the form and formulae of the control mechanisms must be set out in the F&A.[113]

The AER's Draft Decision is that the form of control mechanism for SCS is a revenue cap and the control mechanism for ACS is a price cap as set out in the Final F&A.[114]

The AER's Draft Decision and Ergon Energy Network's responses are set out below.

12.4.1 Standard control services

Ergon Energy Network's Revised Regulatory Proposal accepts the AER's Draft Decision for SCS, including the following:

- the control mechanism formulae and formula parameter definitions for SCS, including:
  - the metering-specific definitions for legacy metering services (which have been reclassified from ACS to SCS), and
  - definitions for the I, B, C and X factors
- the metering services true-up mechanism
- deliberately under-recovered revenue
- unpaid network charges resulting from retailer of last resort events
- side constraint mechanism
- reporting on designated pricing proposal charges, and
- reporting on jurisdictional scheme amounts and rounding inputs in the annual pricing proposal process.

12.4.2 Alternative control services

Ergon Energy Network's Revised Regulatory Proposal accepts the AER's Draft Decision in relation to ACS as follows:

- the control mechanism formulae and formula parameter definitions for ACS, including the new margin and tax factor definitions
- provision for the addition of new ACS during the 2025-30 regulatory control period, and
- requirements relating to transparency of billing for quoted services.

[112] Clause 6.2.5(a) of the NER.
[113] Clauses 6.12.3(c) and 6.12.3(c1) of the NER.
[114] AER, *Draft Decision, Energex and Ergon Energy Electricity Distribution Determination 2025-2030, Attachment 14 – Control Mechanisms*, September 2024, p. 1.

12.5 Negotiating framework

Although none of Ergon Energy Network's services will be classified as negotiated distribution services in the 2025-30 regulatory control period, we are required to submit a negotiating framework to the AER for approval.[115]

The AER's Draft Decision is to accept Ergon Energy Network's proposed negotiating framework submitted with our Regulatory Proposal.[116]

Ergon Energy Network accepts the AER's Draft Decision.

12.6 Pass through events

The cost pass through mechanism allows Ergon Energy Network to seek approval to recover a material increase in costs incurred, or to pass on a significant cost saving made, because of an event that impacts the provision of direct control services during the regulatory control period.

The NER allows all DNSPs to apply for a cost pass through for prescribed events (i.e. regulatory change, service standard, tax change and retailer insolvency) and to nominate additional pass through events in its Regulatory Proposal.[117]

Ergon Energy Network proposed four nominated pass through events for the 2025-30 regulatory control period as follows:

- insurance coverage event
- insurer's credit risk event
- terrorism event, and
- natural disaster event.

The AER's Draft Decision is to accept Ergon Energy Network's nominated pass through events consistent with the Regulatory Proposal, subject to minor amendments to the definition proposed for the insurance coverage event.[118]

Ergon Energy Network has accepted and adopted the AER's Draft Decision on the nominated pass through events and event definitions for the 2025-30 regulatory control period.

12.7 Contingent projects

Ergon Energy Network did not propose any contingent projects for the 2025-30 regulatory control period. Therefore, the AER did not make a decision under clause 6.12.1(4A) of the NER.[119]

[115] Clause 6.8.2(c)(5) of the NER.
[116] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Attachment 17 – Negotiated services framework and criteria,* September 2024, p. 1.
[117] Clauses 6.6.1(a1) and 6.6.1(a1)(5) of the NER.
[118] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Attachment 15 – Pass through events*, September 2024, p. 1.
[119] AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025 to 2030, Overview* , September 2024, p. 32.

12.8 Connection policy

The NER require DNSPs to prepare a connection policy setting out the circumstances in which a retail customer or real estate developer may be required to pay a connection charge for the provision of a connection service under Chapter 5A.[120]

Ergon Energy Network submitted our connection policy for the 2025-30 regulatory control period with the Regulatory Proposal.

The AER's Draft Decision was to approve Ergon Energy Network's proposed connection policy for the 2025-30 regulatory control period.[121]

Ergon Energy Network accepts the AER's Draft Decision.

12.9 Confidential information

Our confidentiality template (Attachment 12.02) sets out the information provided as part of this Revised Regulatory Proposal for which Ergon Energy Network is claiming confidentiality.

12.10 Supporting documentation

The following documents support this chapter:

Document Name	Reference	File name
Classification of services	12.01	Ergon - 12.01 - Classification of Services - November 2024 - public
Confidentiality template	12.02	Ergon - 12.02 - Confidentiality template - November 2024 - public

120 Clause 6.7A.1 of the NER.

121 AER, *Draft Decision, Ergon Energy Electricity Distribution Determination 2025-2030, Attachment 18 – Connection policy*, September 2024, p. 2.

13.
Glossary

Chapter 13: Glossary

Term	Meaning
$, nominal	These are nominal dollars of the day
$, real 2024-25	These are dollar terms as at 30 June 2025
2025-30 regulatory control period	The regulatory control period commencing 1 July 2025 and ending 30 June 2030
ACS	Alternative control service
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
CAC	Connection asset customer
CAM	Cost allocation methodology
Capex	Capital expenditure
CBA	Cost-benefit analysis
CESS	Capital Expenditure Sharing Scheme
CPI	Consumer price index
Current regulatory control period or current period	The regulatory control period commencing 1 July 2020 and ending 30 June 2025
CSIS	Customer Service Incentive Scheme
DMIAM	Demand Management Innovation Allowance Mechanism
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
Dynamic connection	Dynamic connections will allow customers to access increased network capacity at times when the network is not constrained by receiving dynamic operating envelopes rather than setting static limits
Dynamic operating envelopes	Dynamic operating envelopes vary limits over time, based on the capacity or other capability of the network in near real time. This includes, for example, export and import limits at the local network or power system as a whole
EBSS	Efficiency Benefits Sharing Scheme
Energy Queensland	Energy Queensland Limited
ESIS	Export Service Incentive Scheme
F&A	Framework and Approach
GWh	Gigawatt hours
ICC	Individually calculated customer
ICT	Information and communications technology
kN	Kilonewton
kV	Kilovolt
kVA	Kilovolt ampere
kW	Kilowatt
kWh	Kilowatt hour
LED	Light emitting diode
LRMC	Long run marginal cost
MW	Megawatts

Chapter 13: Glossary

Term	Meaning
NEM	National Electricity Market
NER	National Electricity Rules
Next regulatory control period or forecast period	The regulatory control period commencing 1 July 2025 and ending 30 June 2030
NPV	Net present value
Opex	Operating and maintenance expenditure
PIR	Post implementation review
PoE	Probability of exceedance
Previous regulatory control period or previous period	The regulatory control period commencing 1 July 2015 and ending 30 June 2020
PTRM	Post tax revenue model
PV	Photovoltaic (solar PV)
RAB	Regulatory asset base
Regulatory Proposal	Ergon Energy Network's Regulatory Proposal for the next regulatory control period submitted under clause 6.8 of the NER
RFM	Roll forward model
RIN	Regulatory information notice
RRG	Reset Reference Group
SAC	Standard asset customer
SAPS	Stand-alone power system
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SCADA	Supervisory control and data acquisition
SCS	Standard control service
STPIS	Service target performance incentive scheme
TAB	Tax asset base
TOU	Time of use
V	Volt
VCR	Value of customer reliability
WACC	Weighted average cost of capital

Part of Energy Queensland

Project team: RDP2025Connect@energyq.com.au

ergon.com.au

Ergon Energy Network
PO Box 1090
Townsville QLD 4810