Draft Decision

Energex Electricity Distribution Determination 2025 to 2030

(1 July 2025 to 30 June 2030)

Overview

September 2024

AUSTRALIAN ENERGY REGULATOR

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Amendment record

Version	Date	Pages
1	23 September 2024	30

Invitation for submissions

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

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

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

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

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

Parties wishing to submit confidential information should:

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

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

Predetermination conference

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

List of attachments

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

The draft decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

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

Attachment 13 – Classification of services

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Attachment 18 – Connection policy

Attachment 19 – Tariff structure statement

Attachment 20 – Metering services

Executive summary

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Our assessment of Energex's proposal

This draft decision allows Energex to recover $8,703.6 million ($ nominal, smoothed) in main standard control services (SCS) revenue from its customers for the 2025–30 period. This is $194.2 million less than the $8,897.8 million that Energex proposed. Our draft decision would lead to an average annual increase of $39 or 1.8% in consumer bills over the 2025–30 period.

Our draft decision revenue is $2,584.6 million more than Energex's allowed revenue in the 2020–25 period in nominal terms.[2] We estimate that approximately 53% of the increase from the 2020–25 period is driven by market factors including higher inflation and interest rates. The other 47% of the increase is driven by expenditure and other controllable factors.

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

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

While we have accepted the majority of the required revenue, there are areas, particularly in the proposed capex, that we have adjusted as we were not provided with sufficient evidence to support the prudency and efficiency of the forecast.

Our draft decision does not accept Energex's forecast capex. Our alternative total forecast capex of $2,801 million is 16% lower than Energex's forecast of $3,341 million. Our draft

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

2 Adjusting for the impact of inflation, our draft decision revenue is 15.7% higher than Energex's allowed revenue for the 2020–25 period.

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

decision on Energex's forecast capex is a placeholder subject to further supporting information being provided, largely around our concerns regarding aspects of augmentation expenditure (augex), resilience, Information and Communications Technology (ICT) and Property.

We found that Energex may have adopted a more conservative application of its augex Safety Net Targets than what is set out in its Distribution Authority and did not provide adequate evidence to support its proposal. We are open to further information at the revised proposal stage to support our final decision. We also identified issues with the supporting information provided by Energex on ICT and resilience.

Energex has done well to justify other areas of its capex proposal, which has led to our draft decision to accept Energex's replacement expenditure (repex), CER and cyber security capex proposals. Energex's repex forecasts recognise the need to bring forward Olympic-related investments. We also found Energex has balanced the objective of enabling customers to benefit from CER and the need to integrate CER efficiently into its current network.

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

Our draft decision accepts Energex's proposal to reclassify metering services from alternative control services to standard control services and to socialise these costs across low voltage customers. This is due to the outcomes of the Australian Energy Market Commission's (AEMC's) metering review which is seeking to replace historical accumulation meters with smart meters by 2030. Energex's proposal is consistent with our recent decisions which focussed on implementing regulatory settings that best protect consumer, particularly vulnerable consumers, from price spikes during the transition. Our draft decision allows Energex to recover $377.2 million from its customers for the provision of metering services.

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

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

Contents

1 Our draft decision

Our draft decision allows Energex to recover a total revenue of $9,080.8 million ($ nominal, smoothed) from its consumers from 1 July 2025 to 30 June 2030 which comprises:

- $8,703.6 million in main standard control services (SCS) revenue
- $377.2 million in metering revenue.[4]

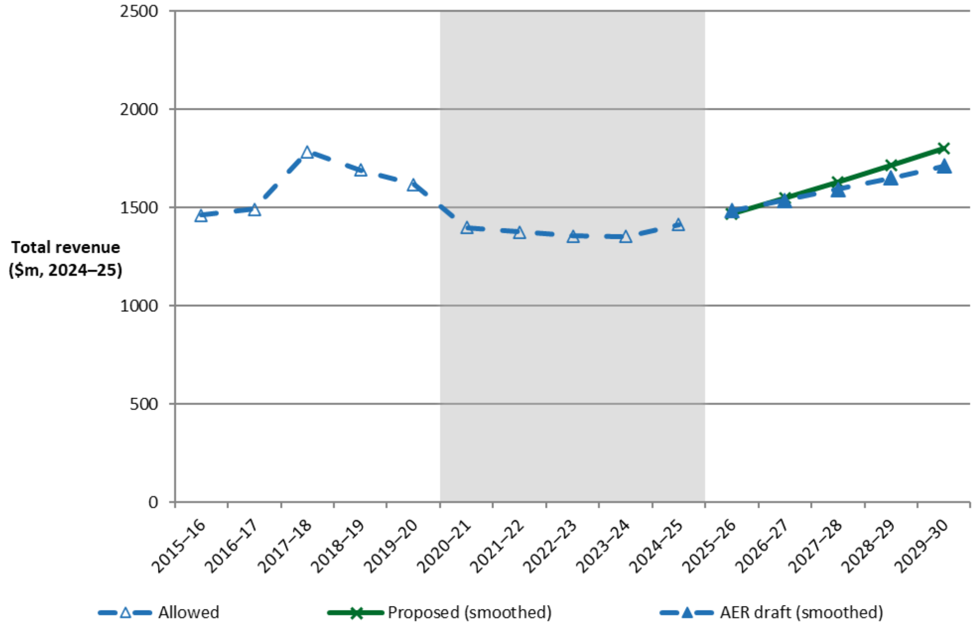
Our draft decision revenue is $2,584.6 million more than Energex's allowed revenue in the 2020–25 period in nominal terms.[5] In the sections below we briefly outline what is driving Energex's main SCS revenue, and the key differences between our draft decision revenue of $8,703.6 million and the $8,897.8 million in Energex's proposal.[6]

1.1 What is driving revenue?

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

In real terms, this draft decision would allow Energex to recover $7,977.6 million ($2024–25, smoothed) over the 2025–30 period. This is 15.7% higher than our decision for the 2020–25 period. Changes in Energex's revenue over time are shown in Figure 1.

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



Source: AER analysis.

[4] This is $17.2 million less than the $394.4 million that Energex proposed for metering.

[5] Adjusting for the impact of inflation, our draft decision revenue is 15.7% higher than Energex's allowed revenue for the 2020–25 period.

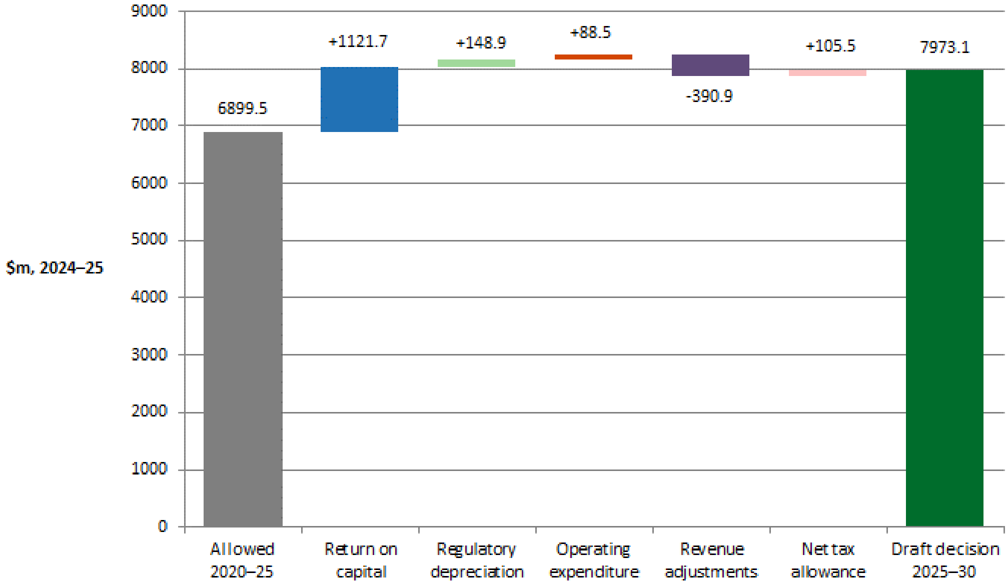
[6] This overview separates main SCS revenue from metering SCS revenue (see Attachment 20) for ease of comparison with previous regulatory periods. Moreover, most metering costs are temporary.

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

- return on capital, which is based on the opening regulatory asset base (RAB), forecast capex and rate of return. This is $1,121.7 million (32.2%) higher than the 2020–25 period, driven by:
  - a higher rate of return being applied in the 2025–30 period, in accordance with the 2022 *Rate of Return Instrument*
  - an increase in the RAB due in part to higher actual inflation in the 2020–25 period
  - higher forecast capex in the 2025–30 period
- return of capital (regulatory depreciation), which is $148.9 million (15.0%) higher than the 2020–25 period, driven primarily by higher straight-line depreciation due to higher actual and forecast capex for short lived assets
- net tax amount, which is $105.5 million (420.9%) higher than the 2020–25 period, primarily due to a higher return on equity and regulatory depreciation determined in this draft decision compared to the 2020–25 period
- opex (for main standard control services), which is $88.5 million (4.0%) higher than the opex forecast we approved in the 2020–25 period, driven primarily by the trend forecast and the network visibility step change.

Figure 2 also shows that our draft decision provides for a reduction in the building block for revenue adjustments, which is $390.9 million lower than the 2020–25 period, mainly due to the large negative Efficiency Benefit Sharing Scheme (EBSS) and Capital Expenditure Sharing Scheme (CESS) outcomes applied in this draft decision.

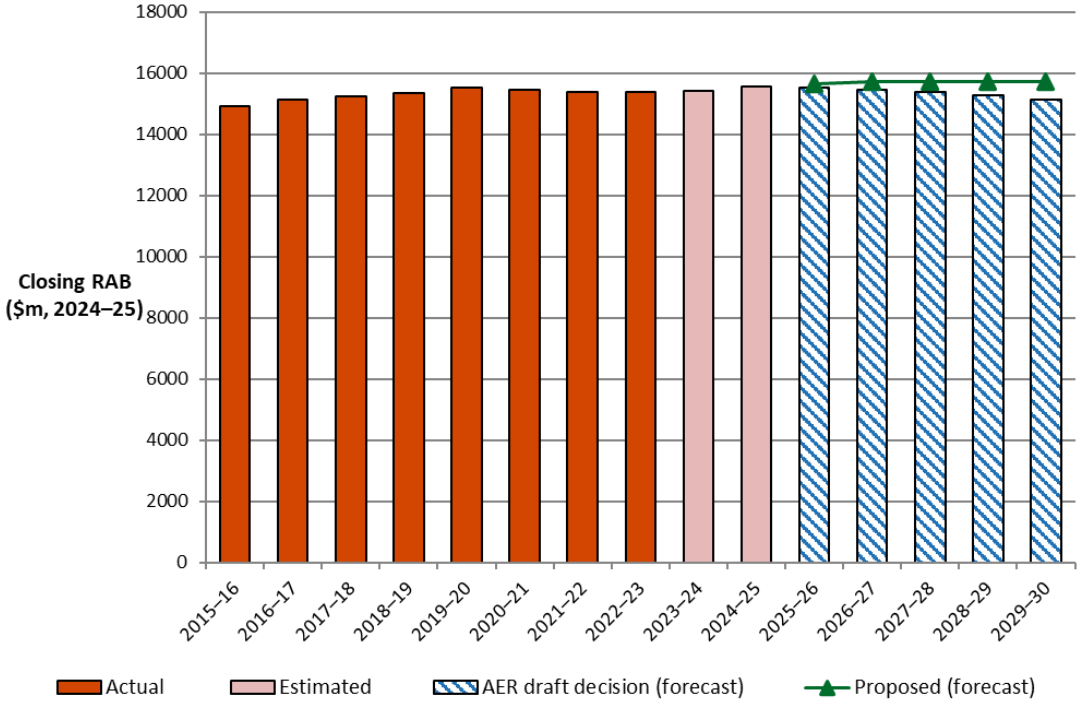
Figure 2 Changes in total revenue between 2020–25 period and 2025–30 period ($ million, 2024–25 unsmoothed)



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

Figure 3 shows the value of Energex's RAB over time in real terms. After a RAB increase of 0.2% over the 2020–25 period, our draft decision is expected to result in a forecast RAB reduction of $433.4 million (2.8%) over the 2025–30 period. This reduction in RAB is driven by our reduced forecast capex and a higher forecast straight-line depreciation over the 2025–30 period compared to the 2020–25 period.

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



Source: AER analysis.

1.2 Key differences between our draft decision and Energex's proposal

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

- lower capex forecasts, primarily driven by reductions in augex.
- higher negative revenue adjustments, primarily driven by a penalty for CESS true-up for 2019–20.

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

- lower return on capital, driven by reduced forecast capex, lower rate of return[7] and a lower opening RAB

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

- lower regulatory depreciation amount, driven by our lower opening RAB, forecast capex and higher expected inflation rate in our draft decision than at the time of Energex's proposal.

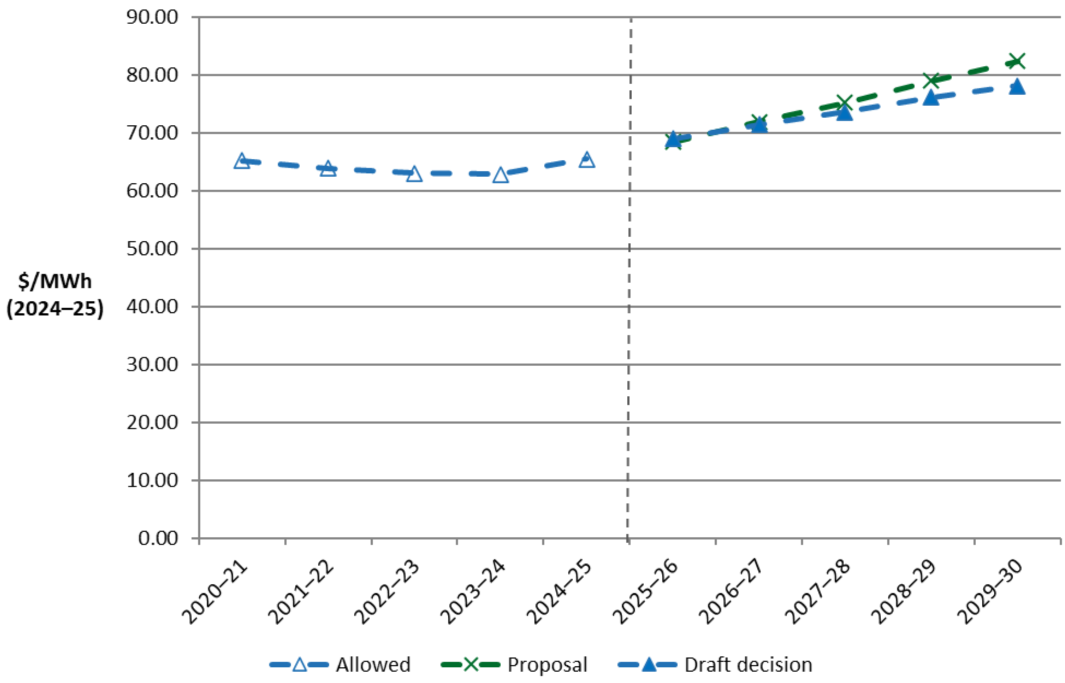
The reductions we made to Energex's total revenue are partially offset by our higher estimated cost of corporate income tax amount, driven by lower tax depreciation from our reduced capex. The lower tax depreciation increases the cost of corporate income tax as it is a component of tax expense.

Energex also proposed to reclassify the legacy metering services following the AEMC's final decision of the Metering review.[8] As a result, Energex proposed legacy metering costs be reclassified to standard control services.

1.3 Expected impact of our draft decision on electricity bills

Energex recovers its regulated revenue through distribution charges, set annually by reference to the tariff structure statement and pricing formulae approved as part of this decision. Figure 4 shows the modelled impact of distribution charges under this draft decision and the proposal in real terms.

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



Source: AER analysis.

The draft decision is estimated to increase Energex's average distribution charges by around 17.5% in real terms by 2029–30 compared to 2024–25, or an average increase of 3.3% per

8 Energex, *2025-30 Regulatory Proposal*, February 2024, pp. 180–181.

annum.[9] This estimate will be subject to ongoing revenue adjustments and changes in consumer energy consumption.

Potential bill impact

Energex's distribution charges make up around 27.1% of its residential customers' electricity bills and 26.5% of its small business customers' electricity bills. Other components of the electricity supply chain—the cost of purchasing energy from the wholesale market, transmission network charges, environmental schemes and the costs and margins applied by electricity retailers in determining the prices they will charge consumers for supply—also contribute to the prices ultimately paid by consumers.[10] These sit outside the decision we are making here but will also continue to change throughout the period.

This is a draft decision, and final decision outcomes are likely to change. In nominal terms, which include the effect of expected inflation, the impact of this draft decision would be an increase to the distribution component of customers' electricity bills. For illustrative purposes only, the modelled impact of our draft decision on the average annual electricity bill for a customer in Energex's network area, as it is today, would be:[11]

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

Our decision on Energex's proposal will set the revenue allowance that forms the major component of its network charges for the next 5 years. It provides a baseline or starting point for that period.

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

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9 The average increase to indicative network charges of 3.3% ($2024–25) per annum reflects two components: 1) The draft decision smoothed revenue average increase of 3.7% per annum ($2024–25); and 2) The forecast energy delivered in Energex's distribution network area which is expected to increase on average by 0.4% per annum.

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

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

1.4 Energex's consumer engagement

Consumer engagement during the regulatory process is an important way to provide us with supporting evidence that proposals have been aligned with consumer interests and expectations. We introduced guidance on our expectations for consumer engagement to network businesses in December 2021.[12]

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

1.4.1 Energex's engagement on its proposal

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

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

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

The issue of affordability is a key theme of Energex's proposal that was raised by consumers. However, the absence of meaningful and comprehensive consultation on future investment decisions with end consumers and the RRG has meant that the issue of affordability was unable to be addressed.

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

1.4.2 What we've heard from stakeholders

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

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

We received 22 submissions on Energex's proposal submitted on 31 January 2024, and our issues paper published 26 March 2024. The CCP30 and RRG reiterated their advice throughout the pre-engagement process that the scope of consumer engagement was too narrow and that there should have been an opportunity for consumers to influence parts of the proposal that have a significant impact on consumer bills.

> *The depth and breadth of engagement on other topics was limited due to time constraints. Specifically, this meant that beyond publication of Draft Plans, there was very little engagement on the capex and opex building blocks with consumers generally. Engagement with the RRG had a wider scope but that was still substantially less than is expected under the Better Resets Handbook or what RRG members have seen on other recent electricity distribution resets.*[13]

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

> *[t]he commitment to feed customer input back into much of the key aspects of the proposals was not strong, particularly around affordability. Customers were canvassed more on issue of timing than the need of the investment itself. Key information was framed as 'inform', with investments presented as being 'already locked in.' Detailed deep dives were held after the regulatory proposal proposed expenditure was largely finalised and signed off.*[14]

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

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[13] EQL RRG, *Submission* – *Energex & Ergon Energy 2025-30 Electricity Determination*, May 2024, p. 3.

[14] CCP30, *Response to EQL proposal and AER Issues Paper*, May 2024, p. 3.

2 Key components of our draft decision

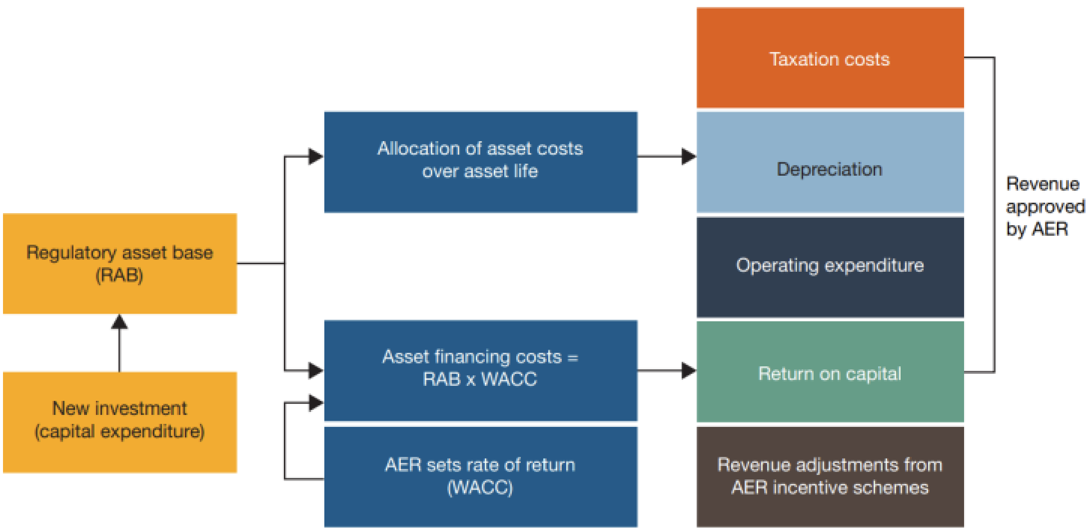
Building block approach

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

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

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

Figure 5 The building block model to forecast network revenue



Source: AER.

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

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

Revenue smoothing

Our draft decision incudes a determination of Energex's annual revenue requirement (ARR) (unsmoothed revenue) and annual expected revenue (smoothed revenue) across the 2025–30 period. The smoothed revenues we set in this draft decision are the amounts that Energex will target for its annual pricing purposes and recover from its customers for the provision of standard control services for each year of the 2025–30 period.[15]

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

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

On the other hand, our draft decision allows for higher revenues than those determined in the 2020–25 period for the reasons discussed in section 1.1 of this Overview. We have smoothed the expected revenues over the 2025–30 period for Energex. Our draft decision results in an initial increase of 6.9% (nominal) to the expected revenue in 2025–26, followed by average annual increases of 6.6% during the remaining 4 years of the 2025–30 period (2026–27 to 2029–30).

2.1 Regulatory asset base

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

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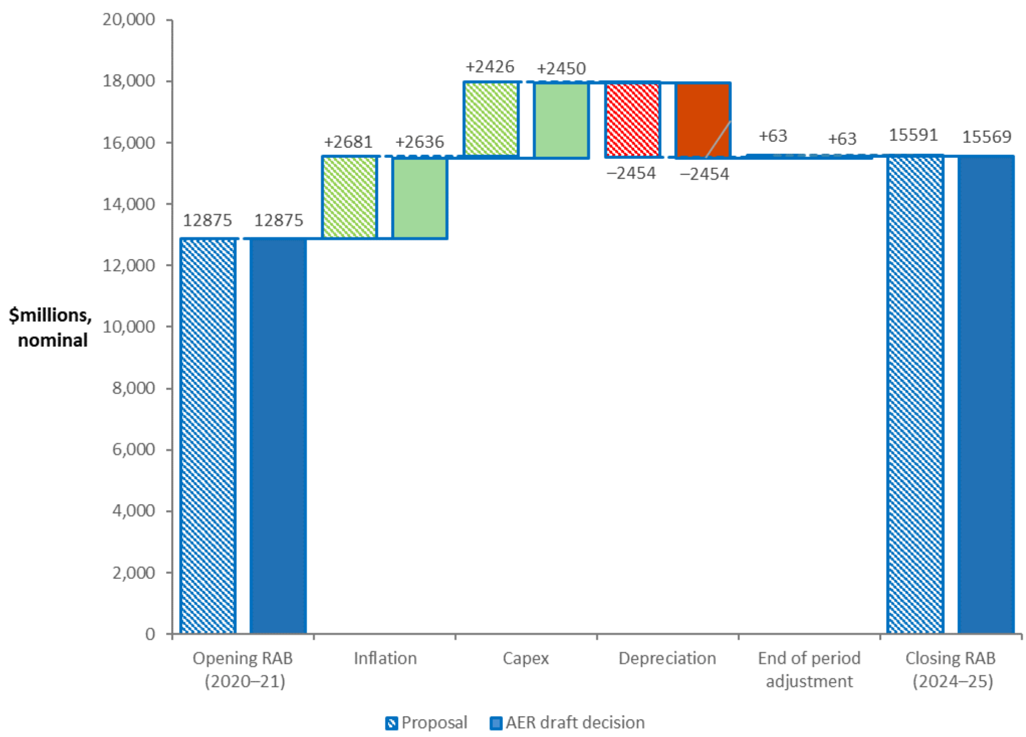
15 Our draft decision expected revenues have not factored in the legacy metering costs being moved to standard control services, any changes arising from incentive scheme amounts, cost pass throughs or unders/overs reconciliation that usually occur in the annual pricing process to come up with the total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

determine the return on capital and regulatory depreciation building blocks. It substantially impacts Energex's revenue requirement, and the price consumers ultimately pay. Other things being equal, a higher RAB would increase both the return on capital and regulatory depreciation components of the revenue determination.

For this draft decision, we have determined an opening RAB value of $15,569.5 million ($ nominal) as at 1 July 2025. This value is $21.2 million (0.1%) lower than Energex's proposed opening RAB value of $15,590.7 million. This reduction is largely due to the updates we made to the consumer price index (CPI) inputs for 2023–24 and 2024–25 in the roll forward model (RFM) to reflect more up-to-date values. Figure 6 shows the key drivers ($ nominal) of the change in Energex's RAB over the 2020–25 period compared to its proposal.

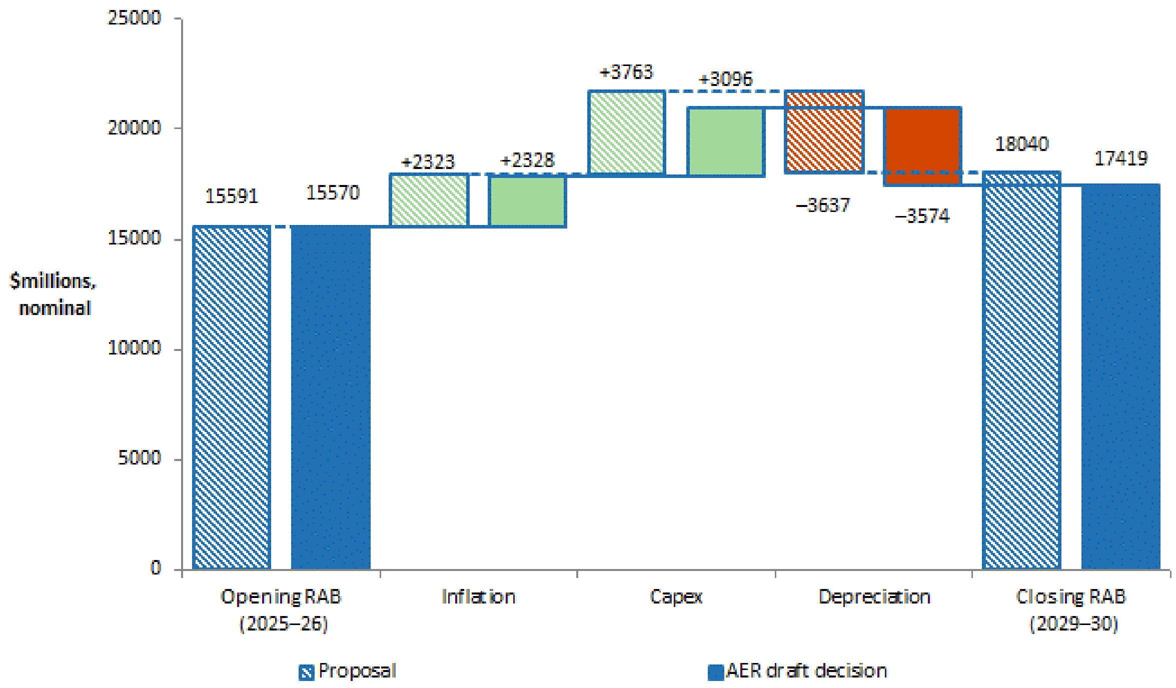
Figure 6 Key drivers of changes in the RAB over the 2020–25 period – proposal compared with AER's draft decision ($ million, nominal)



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

Figure 7 likewise shows the key drivers of the change in Energex's forecast RAB over the 2025–30 period compared to its proposal. Our draft decision projects an increase of $1,849.8 million (11.9%) to the RAB by the end of the 2025–30 period compared to the $2,449.4 million (15.7%) increase in Energex's proposal. We have determined a projected closing RAB of $17,419.3 million ($ nominal) as at 30 June 2030, which is $620.8 million (3.4%) lower than Energex's proposal of $18.040.1 million. This lower value is mainly due to our draft decision to reduce Energex's proposed forecast capex (discussed in attachment 5). It also reflects our draft decisions on the opening RAB as at 1 July 2025, forecast depreciation and expected inflation.

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



Source: AER analysis.
Note: Capex is net of forecast disposals and capital contributions. It is inclusive of the half-year WACC to account for the timing assumptions in the Post-tax revenue model (PTRM).

2.2 Rate of return and value of imputation credits

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

Energex's proposal and this draft decision applies the 2022 Rate of Return Instrument:[16]

- Our draft decision applies a rate of return of 6.04% for the first year of the regulatory period, which approximates the placeholder rate of return of 6.04% used in Energex's proposal.
- Our draft decision and Energex's proposal applies a value of imputation credits (gamma) of 0.57 as set out in the 2022 Instrument.[17]

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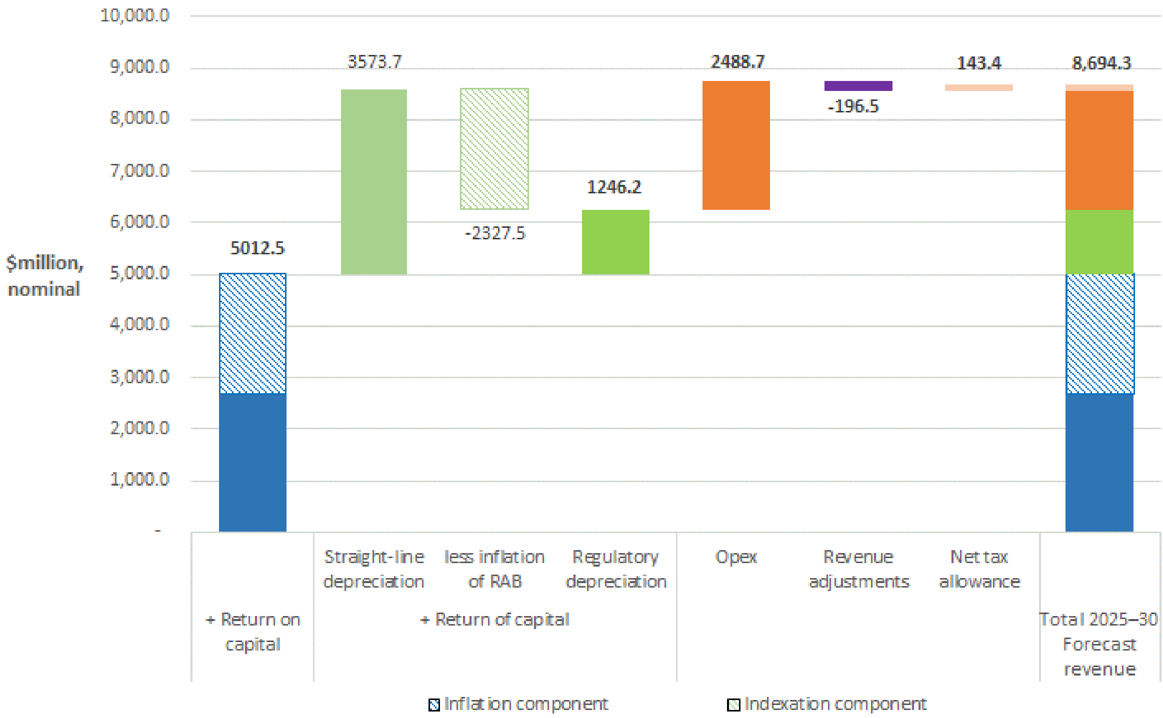
16 The 2022 *Rate of Return Instrument* was amended in March 2024. See https://www.aer.gov.au/publications/guidelines-schemes-models/rate-of-return-instrument-2022/final-decision

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

Our estimate of expected inflation for the purposes of this draft decision is 2.85% per annum. It is an estimate of the average annual rate of inflation expected over a five-year period based on the approach adopted in our 2020 Inflation Review[18] and the forecast from the Reserve Bank of Australia's August 2024 Statement on Monetary Policy.[19] This is higher than the estimate used in Energex's proposal (2.80%), which was taken from an earlier Statement on Monetary Policy.

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

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



Source: AER analysis.

[18] AER, *Final position – Regulatory treatment of inflation*, December 2020.

[19] RBA, *Statement on Monetary Policy, Table 3.1: Detailed Forecast Table*, August 2024, p. 57.

2.3 Regulatory depreciation (return of capital)

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

Our draft decision determines a regulatory depreciation amount of $1,246.2 million ($ nominal) for the 2025–30 period. This is a reduction of $67.8 million (5.2%) from Energex's proposal of $1,314.0 million.

This reduction is primarily due to our draft decisions to reduce forecast capex and the opening RAB as at 1 July 2025 which have reduced straight-line depreciation for the 2025–30 period. The magnitude of the reduction is further increased by a slightly higher RAB indexation,[20] largely due to applying a higher value of expected inflation than that proposed by Energex.

2.4 Capital expenditure

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

Our draft decision is to not accept Energex's forecast total capex of $3,341.1 million ($2024-25) for the 2025-30 period. Our alternative forecast is $2,801.0 million which is 16.2% lower than Energex's forecast. Table 1 sets out our draft decision for Energex's forecast capex by capex category.

Table 1 AER's draft decision by capex category ($million, $2024–25)

Capex category	Energex's proposal	Forecast assessed	AER's draft decision
Repex	920.9	913.2	913.2
Resilience	N/A	50.0	25.1
Augex	595.3	528.9	324.0
Connections	321.0	321.0	321.0
Fleet	198.5	198.5	168.6
Property	151.9	151.9	143.7
Cyber security	N/A	48.1	48.1
ICT	266.0	242.1	195.4
CER integration	54.1	54.1	54.1
Other non-network	25.2	25.2	25.2
Capitalised overheads	838.1	838.1	615.7

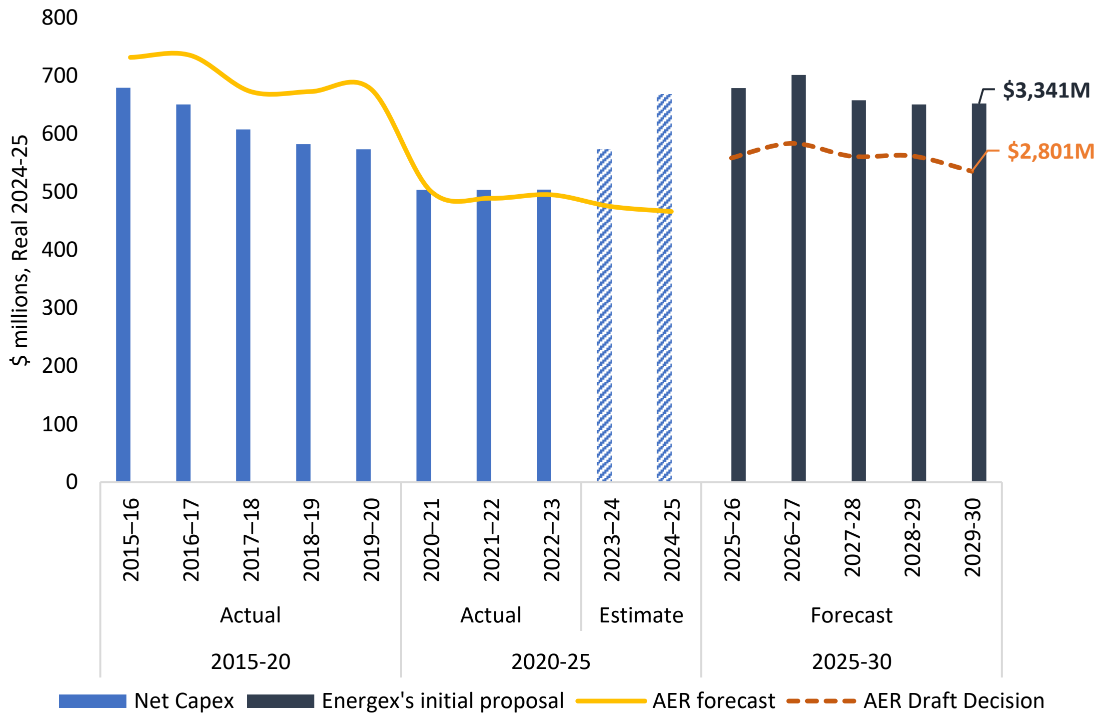
20 Since RAB indexation is deducted from straight-line depreciation, the higher RAB indexation has also resulted in a lower regulatory depreciation.

Total capex (excluding capcons)	**3371.2**	**3371.2**	**2834.1**
less asset disposals	-30.1	-30.1	-30.1
Modelling adjustments			-3.0
Net capex	**3341.1**	**3341.1**	**2801.0**

Source: Energex and AER analysis. Numbers may not sum due to rounding.
Note: Energex's proposal differs from its proposal documents as it submitted an updated capex model on 28 June 2024. It originally proposed net capex of $3,408.3. Our forecast assessed recategorised capex from Energex's proposal to align with how we assessed each category. We recategorised $7.7 million of repex, $16.4 million of augex, and $24.0 million of ICT to cyber security. We also recategorised $50.0 million of augex to resilience.

Figure 9 shows Energex's historical capex trend, its proposed forecast for the 2025–30 regulatory control period, and our draft decision. As can be seen, Energex had a steady decrease in actual capex until 2022-23. Energex estimated a higher level of capex in the last two estimate years of the 2020-25 period relative to the first three years of the 2020-25 period. Energex forecast this higher level of capex to continue in the 2025-30 period.

Figure 9 Energex's historical and forecast capex ($2024–25 million)



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

We have accepted some parts of Energex's forecast where it provided sufficient evidence to support the prudency and efficiency of its forecast; this being in the areas of repex, cyber security capex, CER and other non-network.

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

We note that Energex did not satisfy any of the capex expectations in the Handbook. In particular, its forecast capex for the 2025-30 period is a 21.4% step up from the current 2020-25 period, where it is proposing a step up in all capex categories except for ICT. Submissions in response to the Issues paper also noted the lack of genuine consumer engagement on its capex proposal. There was little evidence of how Energex had regard to consumer feedback in developing its capex proposal especially on the key priority issue of affordability.

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

- *Augex* – Energex did not provide sufficient evidence to support a 68% step up in its forecast relative to the current period. In particular, we found Energex may have adopted a more conservative application of its Safety Net Targets than what is set out in its Distribution Authority and did not provide adequate evidence to support its proposal. We also consider it has not provided sufficient information to support the increase in unit rate relating to its clearance to ground and clearance to structure program.
- *ICT* – In the business cases we assessed, we found that Energex did not provide adequate evidence to support the prudency and efficiency of its preferred options. Some of its preferred options did not have the highest ranked NPV and some of its business cases had no quantitative benefits while the qualitative benefits lacked detail. The information on the scope of works and costs provided insufficient detail to determine efficiency of the costs.
- *Resilience* – Energex did not provide much of the evidence expected in reliance-related proposals that the AER set out in its guidance note on network resilience. While we have accepted its forecast for its bushfire and flood program, we have concerns about the prudency and efficiency of its mobile substations program and mobile generation program, and therefore have not accepted this component of its resilience expenditure.
- *Fleet* - We found that Energex did not provide sufficient evidence to support a 46% step up in its forecast relative to the current period. In particular, Energex did not provide sufficient justification for its proposed changes to the replacement strategies of elevated work platforms (EWP) and crane borers. We have also adjusted its forecast lower to reflect a lower FTE uplift given the relationship between the FTE uplift and capex.
- *Capitalised overheads* – We found the methodology that Energex has used to calculate its capitalised overheads to not be reasonable. Our alternative estimate applies the AER’s standard methodology.

2.5 Operating expenditure

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

Our draft decision is to accept Energex’s total main standard control services opex forecast of $2,284.9 million ($2024–25), including debt raising costs. This is because our alternative estimate of $2,363.8 million ($2024–25) is higher ($78.9 million ($2024–25), or 3.5%) than

Energex's total opex forecast proposal. Therefore, we consider that Energex's total opex forecast satisfies the opex criteria.[21]

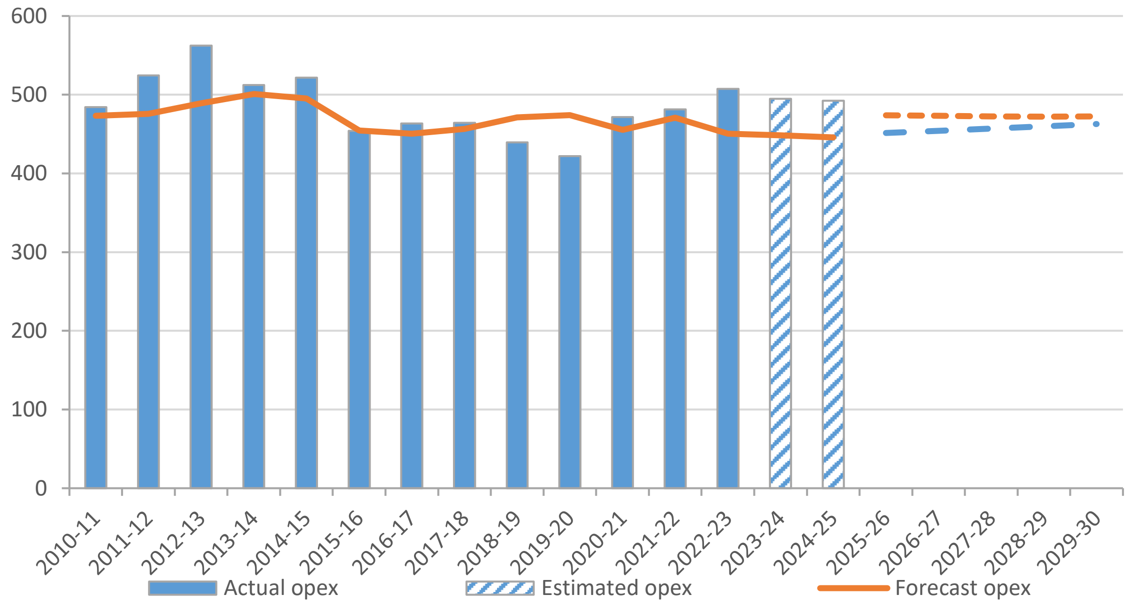
We recognise the forecast moderation in opex by Energex over the next regulatory control period, including in terms of its base year efficiency, productivity adjustments and only one proposed step change for network visibility.

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

- $162.5 million ($2024–25) (6.6%) lower than Energex's actual (and estimated) opex in the 2020–25 regulatory control period
- $14.1 million ($2024–25) (0.6%) higher[22] than the opex forecast we approved in our final decision for the 2020–25 regulatory control period.

In Figure 10, we compare our alternative estimate of opex (the orange dashed line) to Energex's proposal (the blue dashed line) for the next regulatory control period. We also show the forecasts we approved for the last two regulatory control periods and Energex's actual and estimated opex over these periods. As can be seen, our draft decision (Energex's proposal) represents a slight increase relative to the level of opex we forecast for the 2020–25 regulatory control period. This increase is driven by the trend forecast and the network visibility step change. However, it is lower than Energex's actual and forecast opex over the last three years of the current regulatory control period.

Figure 10 Historical and forecast opex ($2024–25)



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

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

22 This difference is calculated using the opex allowance for the five-year 2020–25 period converted to real $2024–25 using unlagged inflation. The difference of $88.5 million (4.0%) stated in section 1.1 has been calculated using lagged inflation.

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

- Energex proposed a 5.9% efficiency adjustment to its base year opex and did not include transition costs to provide it with a glide path over the next regulatory control period to the more efficient level of base opex it proposed. We applied a slightly lower efficiency adjustment of 5.2% but added $50.1 million ($2024–25) in transition costs. The transition costs recognise it will take time, and involve costs, to implement the required programs to realise opex reductions. Overall, this means we made a lower total efficiency adjustment to base opex.
- For the productivity growth forecast, Energex proposed 1.0% per annum productivity growth while we adopted our standard 0.5% growth rate.

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

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

2.6 Corporate income tax

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

Our draft decision determines an estimated cost of corporate income tax amount of $143.4 million ($ nominal) for Energex over the 2025–30 period. This is an increase of $32.7 million (29.5%) from Energex's proposal of $110.8 million.

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

2.7 Revenue adjustments

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

- EBSS - a revenue adjustment (penalty) of $119.7 million ($2024–25) under the EBSS. This is slightly lower than Energex's proposed penalty of $121.8 million ($2024–25) because we have used the most reflect inflation figures. The full detail on our draft decision for the EBSS is in Attachment 8.
- CESS - a revenue adjustment (penalty) of $72.8 million ($2024–25) under the CESS. This is higher than Energex's proposed penalty of $48.2 million ($2024–25) because we have used the most recent inflation data and adjusted the CESS applicable capex to exclude Energex's ICT overspend. The full detail on our draft decision for the CESS is in Attachment 9.
- DMIAM - comprises a fixed allowance of $0.2 million ($2017), plus 0.075% of the annual revenue requirement for each regulatory year, as set out in our PTRM. In our final distribution determination, we will determine the amount of the DMIAM allowance for Energex for the 2025–30 period, based on the final PTRM for Energex.

The combined effect of these revenue adjustments is a negative $185.3 million ($2024–25) revenue adjustment building block in this draft decision compared to the negative $162.6 million in Energex's proposal.

3 Incentive schemes

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

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

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

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

4 Tariff structure statement

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

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

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

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

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

The tariff structure statement must set out several matters. These include tariff classes, proposed tariffs and the structures and charging parameters, the strategy for introduction of export tariffs, and the approach to setting tariff levels in each year of the regulatory control period.[23] The policies and procedures that will be used to assign customers to tariffs or reassign customers from one tariff to another must also be outlined.

In this determination we must decide whether to approve Energex's tariff structure statements, which will form the basis of annual pricing proposals throughout the 2025–30 period.[24] We are also required to decide the policies and procedures for assigning or re-assigning customers to tariff classes.[25] Principally, we are making a determination on whether the proposed tariff structure statement complies with the pricing principles of the NER, and any other applicable rules. After that, our decision takes the NEO into account and considers whether the tariff structure statement will or is likely to contribute to achievement of the NEO. For tariff structure statements, we consider the NEO elements of price and achievement of jurisdictional emissions reduction targets to be most relevant.

While an indicative pricing schedule must accompany the tariff structure statement, the tariff levels for each tariff for each year of the 2025–30 period are not set as part of this determination.[26] Tariff pricing levels for the regulatory year commencing 1 July 2025 will be subject to a separate approval process in May 2025, after we have made our final revenue determination in April 2024. Tariff price levels for the four years from 1 July 2026 will also be approved on an annual basis.[27]

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

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

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

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

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

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

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

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

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

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

- include further information on the proposed contingent tariff adjustments to remove obsolete tariffs within the 2025–30 period
- include an explicit export tariff transition strategy, convert proposed export charges and basic export levels from demand to energy-based measurement, and include network bill impact analysis for small and large businesses proposed to face two-way pricing
- provide further detail on proposed grid-scale storage tariffs, including more detail on the proposed critical peak pricing mechanism
- offer a time-of-use tariff option for LV large business customers with demand greater than 120 kVA[28] but consumption less than 160 MWh to contribute to the achievement of the NEO, in particular to Queensland's targets for reducing Australia's greenhouse gas emissions (i.e. its net zero 2050 target and its Zero Emission Vehicle Strategy (ZEV Strategy) 2022–2032)[29]
- include further description of control arrangements that are contained in the Queensland Electricity Connections Manual, further explanation of the relationship between the Manual and tariff structure statements, and the extent to which control arrangements influence tariff options, including the proposed new flexible load control tariff.

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

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

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28 kVA = kilovolt amp.

29 AEMC, *Emissions Targets statement under the national energy laws*, June 2024.

5 Metering

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

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

Our draft decision accepts Energex's proposal to reclassify legacy metering as standard control services and the application of a revenue cap. We consider this is the most appropriate outcome because it is consistent with our guidance note and provides an outcome that is in the long-term interests of consumers.[31] It ensures no customer is worse off than other customers as a result of when their legacy meter is replaced. By comparison, customers whose meters are replaced later in the replacement program would incur inequitably higher prices than those whose meters are replaced earlier under the approach in the final F&A.

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

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

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

6 Constituent decisions

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

Constituent component
In accordance with clause 6.12.1(1) of the NER, the AER's draft decision is that the classification of services set out in Attachment 13 will apply to Energex for the 2025–30 regulatory control period, for the reasons set out in that attachment.
In accordance with clause 6.12.1(2)(i) of the NER, the AER's draft decision is to not approve the annual revenue requirement set out in Energex's building block proposal. Our draft decision on Energex's annual revenue requirement for standard control services other than legacy metering services (main standard control services) for each year of the 2025–30 regulatory control period is set out in Attachment 1. Our draft decision on Energex's legacy metering annual revenue requirement for each year of the 2025–30 regulatory control period is set out in Attachment 20.
In accordance with clause 6.12.1(2)(ii) of the NER, the AER's draft decision is to approve Energex's proposal that the regulatory control period will commence on 1 July 2025. Also in accordance with clause 6.12.1(2)(ii) of the NER, the AER's draft decision is to approve Energex's proposal that the length of the regulatory control period will be five years from 1 July 2025 to 30 June 2030.
The AER did not receive a request for an asset exemption under clause 6.4B.1(a)(1) and therefore has not made a decision in accordance with clause 6.12.1(2A) of the NER.
In accordance with clause 6.12.1(3)(ii) and acting in accordance with clause 6.5.7(d) of the NER, the AER's draft decision is to not accept Energex's proposed total forecast capital expenditure. For main standard control services, we do not accept Energex's proposed total forecast capital expenditure of $3,341.1 million ($2024–25). Our draft decision therefore includes an alternative estimate of Energex's total forecast net capex for the 2025–30 regulatory control period of $2,801.0 million ($2024–25). The reasons for our draft decision are set out in Attachment 5. For metering, we accept Energex's proposal forecast of no capex. This is set out in Attachment 20.
In accordance with clause 6.12.1(4)(ii) and acting in accordance with clause 6.5.6(d) of the NER, the AER's draft decision is to not accept Energex's proposed total forecast operating expenditure.

Constituent component
For main standard control services, we accept Energex's proposed total forecast operating expenditure, inclusive of debt raising costs and exclusive of DMIAM of $2,284.9 million ($2024–25). The reasons for our draft decision are set out in Attachment 6. For metering, we do not accept Energex's proposed total forecast operating expenditure forecast of $127.4 million ($2024–25) and replace it with a forecast of $115.8 million ($2024–25). This is set out in Attachment 20.
Energex did not propose any contingent projects and therefore the AER has not made a decision under clause 6.12.1(4A) of the NER.
In accordance with clause 6.12.1(5) of the NER and the 2022 Rate of Return Instrument, the AER's draft decision is that the allowed rate of return for the 2025–26 regulatory year is 6.04% (nominal vanilla) for the reasons set out in Attachment 3. The rate of return for the remaining regulatory years of the 2025–30 period will be updated annually because our decision is to apply a trailing average portfolio approach to estimating debt which incorporates annual updating of the allowed return on debt.
In accordance with clause 6.12.1(5A) of the NER and the 2022 Rate of Return Instrument, the AER's draft decision on the value of imputation credits as referred to in clause 6.5.3 is to adopt a value of 0.57. The reasons for our draft decision are set out in Attachment 3.
In accordance with clause 6.12.1(6) of the NER, and acting in accordance with clause 6.5.1 and schedule 6.2 of the NER, the AER's draft decision on Energex's main standard control services regulatory asset base as at 1 July 2025 is $15,569.5 million ($ nominal). The reasons for our draft decision are set out in Attachment 2. The AER's draft decision on Energex's metering regulatory asset base as at 1 July 2025 is $209.9 million ($ nominal). This is discussed in Attachment 20.
In accordance with clause 6.12.1(7) of the NER, the AER's draft decision on Energex's estimated cost of corporate income tax for main standard control services is $143.4 million ($ nominal) for the 2025–30 regulatory control period. The reasons for our draft decision are set out in Attachment 7 and the amount for each regulatory year of the 2025–30 regulatory control period is set out in the table below.

($ million, nominal)	2025–26	2026–27	2027–28	2028–29	2029–30	Total
Tax payable	46.0	52.0	62.1	83.8	89.7	333.6
Less: value of imputation credits	26.2	29.6	35.4	47.7	51.1	190.1
Net cost of corporate income tax	**19.8**	**22.4**	**26.7**	**36.0**	**38.6**	**143.4**

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

Constituent component
In accordance with clause 6.12.1(8) of the NER, the AER's draft decision is to not approve the depreciation schedules submitted by Energex. For main standard control services, our draft decision substitutes alternative depreciation schedules that accord with clause 6.5.5(b). The regulatory depreciation amount approved in this draft decision is $1,246.2 million ($ nominal) for the 2025–30 regulatory control period. The reasons for our draft decision are set out in Attachment 4. For legacy metering, our draft decision substitutes alternative schedules amounting to regulatory depreciation for the 2025–30 regulatory control period of $209.9 million ($ nominal). This is discussed in Attachment 20.
In accordance with clause 6.12.1(9) of the NER the AER makes the following draft decisions on how any applicable efficiency benefit sharing scheme (EBSS), capital expenditure sharing scheme (CESS), export services incentive scheme (ESIS), service target performance incentive scheme (STPIS), demand management incentive scheme (DMIS), demand management innovation allowance mechanism (DMIAM) or small-scale incentive scheme (customer service incentive scheme) is to apply: • We will apply version 2 of the EBSS to Energex in the 2025–30 regulatory control period. Our reasons are set out in Attachment 8. • We will apply the CESS as set out in the 2023 Capital Expenditure Incentives Guideline to Energex in the 2025–30 regulatory control period. Our reasons are set out in Attachment 9. • We will not apply the ESIS for the 2025–30 regulatory control period. • We will apply our STPIS version 2 to Energex for the 2025–30 regulatory control period. Our reasons are set out in Attachment 10. • We will apply the DMIS and DMIAM to Energex for the 2025–30 regulatory control period. Our reasons are set out in Attachment 11. • We will not apply the customer service incentive scheme (CSIS) to Energex for the 2025–30 regulatory control period. Our reasons are set out in Attachment 10.
In accordance with clause 6.12.1(10) of the NER, the AER's draft decision is that all other appropriate amounts, values and inputs are as set out in this draft determination including attachments.
In accordance with clause 6.12.1(11) of the NER and our framework and approach paper, the AER's draft decision on the form of control mechanisms (including the X factor) for standard control services is a revenue cap. The revenue cap for Energex for any given regulatory year is the total annual revenue calculated using the formula in Attachment 14, which includes any adjustment required to move the Distribution Use of Service (DUoS) and metering unders and overs accounts to zero. The reasons for our draft decision are set out in Attachment 14.

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

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

7 List of submissions

We received 22 submissions in response to Energex 2025-30 distribution revenue proposal. These are listed below.[32]

Submissions from
AER Consumer Challenge Panel (CCP) Sub-Panel 30 (CCP30)
Climate Council
Electric Vehicle Council
Electrical Safety Office (ESO)
Energy2
EQL Reset Reference Group (Engagement Report)
EQL Reset Reference Group
Evie Networks
Master Electricians Australia
Moreton Climate Action Now campaign
Network Energy Services
Noosa Biosphere Reserve Foundation
Noosa Council
Origin Energy
Amanda Pummer
Red Energy and Lumo Energy
Renew Gold Coast Branch
Southeast Queensland Community Alliance (SEQCA)
Southeast Queensland Climate Resilient Alliance (SEQCRA)
Tesla
Zero Emissions 4075 Inc.
Zero Emissions Noosa Inc.

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

Shortened forms

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