Draft decision

Jemena electricity distribution determination

1 July 2026 – 30 June 2031

Overview

September 2025

AUSTRALIAN ENERGY REGULATOR

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Amendment record

Version	Date	Pages
1	30 September 2025	53

Invitation for submissions

Jemena has the opportunity to submit a revised proposal in response to this draft decision by 1 December 2025.

Interested stakeholders are invited to make a submission on both our draft decision and Jemena's revised proposal (once submitted) by Monday, 19 January 2026.

Submissions should be sent to: Vic2026@aer.gov.au and addressed to Dr Kris Funston, Executive General Manager.

Alternatively, you can main submissions to GPO Box 3131, Canberra ACT 2601.

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

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

Parties wishing to submit confidential information should:

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

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

Pre-determination conference

Your engagement is a valuable input to our determination. We encourage all interested stakeholders to join us at our Pre-determination conference on Tuesday, 14 October 2025.

Details of how to register for this forum are available on our website and through Eventbrite.

List of attachments

This document forms part of the AER's draft decision on Jemena's electricity distribution determination for the 2026-31 regulatory control period.

A full list of attachments is provided below.

Overview

1) Annual revenue requirement
2) Capital expenditure
3) Operating expenditure
4) Pass through events
5) Efficiency benefit sharing scheme
6) Capital expenditure sharing scheme
7) Service target performance incentive scheme
8) Demand management incentive scheme and Demand management innovation allowance mechanism
9) Customer service incentive scheme
10) Victorian F-factor incentive scheme
11) Classification of services
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13) Tariff structure statement
14) Alternative control services
15) Metering Services
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Executive summary

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

We exist to ensure energy consumers are better off, now and in the future. We focus on ensuring a secure, reliable, and affordable energy future for Australia as we transition to net zero emissions.

A regulated electricity distribution network service provider (DNSP) must periodically apply to us to determine the maximum allowed revenue it can recover from consumers for using its network.

On 31 January 2025, we received regulatory proposals from 5 Victorian DNSPs for the period 1 July 2026 to 30 June 2031 (2026-31 period).

This is our draft decision for Jemena Electricity Networks [ABN 82 064 651 083] (Jemena), for the period 1 July 2026 to 30 June 2031 (2026-31 period). It is predicated on a series of constituent decisions summarised in section 5 of this Overview.[1]

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

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

We must make our decision in a manner that will, or is likely to, deliver efficient outcomes in terms of the price, quality, safety, reliability and security of electricity supply that will benefit consumers in the long term.

Our decision must also consider targets for reducing Australia's greenhouse gas emissions, as required under the National Electricity Objective (NEO).

When we undertake our assessments, we consider whether we are satisfied that the proposed expenditure by the DNSP reasonably reflects prudent and efficient costs and a realistic expectation of future network demand and cost inputs.

Consumer support is an important part of this assessment. However, even where it is possible to say that a proposal is reflective of consumer views and preferences, this does not displace the AER's role in carefully testing and assessing the prudency and efficiency of proposed expenditure. Submissions have emphasised the importance of this scrutiny in ensuring desired outcomes are delivered at the lowest sustainable cost.[2]

To do this we scrutinise the DNSP's proposed business cases and supporting information, consider advice from our expert consultants, and apply our various analytical tools, such as

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1 NER, cl. 6.12.1

2 Hon Lily D'Ambrosio MP - *Submission - Victorian electricity distribution proposals 2026-31* - June 2025; Origin Energy - *Submission - Victorian electricity distribution proposals 2026-31* - May 2025.

the replacement capital expenditure (repex) model and economic benchmarking for operating expenditure.

In addition, we are informed by stakeholder submissions and consumer preferences and priorities elicited through the DNSP's consumer engagement processes, and from our own Consumer Challenge Panel.

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

The central component of Jemena's proposal is the revenue that it recovers from consumers over the 2026-31 period. We have assessed this by considering the constituent components of Jemena's proposal, including capital expenditure (capex), operating expenditure (opex) and the tariff structure statement (TSS) to ensure it complies with the NER.

Jemena put forward its proposal at a time when network costs are rising across the National Energy Market (NEM), driven by a range of factors that affect reliability, security, and safety. The network is getting older, input costs are rising, digitalisation is increasing the risk of cyber-attacks, and the system is adapting to climate change, more rooftop solar, batteries, electric vehicle charging and large, new loads such as data centres.

On top of that, broader economic pressures like higher interest rates and inflation are also pushing costs up compared with the last 5-year period.

In Victoria, the energy market is undergoing a complex transition. Emissions reduction targets and the transition to net zero, now reflected in the NEO, are driving changes in household and commercial energy use. An increasing number of consumers are responding to incentives to move away from gas appliances, and the electricity grid is now a two-way system as rooftop solar and batteries play a larger role in supply and demand.

These shifts are changing the way consumers are seeking to use electricity, and their expectations of electricity distribution networks. In turn, they are impacting how Jemena and other electricity distribution networks operate and invest in their networks.

At the same time, recent severe weather events have put resilience in the spotlight. Many Victorian consumers experienced extended outages. Victorian government reviews into electricity distribution network resilience, outage planning and operational responses have made several recommendations. Regional reliability and differences in performance between and within networks are also front of mind for many – equally important both in terms of service levels and access to the opportunities the transition provides.

Safety and reliability are enshrined in the NEO and are key components of our decision making. We expect DNSPs to submit proposals that meet their obligations in these areas in a way that is prudent and efficient. Our draft decision underscores the need for Jemena to do further work to ensure capex and opex expenditure proposals meet these objectives.

Network utilisation is in the mid-to-high range in Victoria compared with elsewhere in the NEM. However, we want to see a commitment by networks towards network pricing structures aimed at reducing the amount of network investment required to provide sufficient network capacity and stability during peak demand and export periods.

We encourage network businesses to utilise the revenue determination process to propose tariff design, incentive structures and efficient and prudent expenditure that contributes to achieving the NEO.

A DNSP's revenue proposal must have robust demand forecasts and clear evidence for increased investment in network augmentation in the 2026-31 period. We expect to see business cases that are well supported by analysis.

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

This is the challenging environment in which Jemena has put forward its forecast plans and revenues for the upcoming regulatory control period. This draft decision sets out our assessment of Jemena's proposal and the further work we now encourage it to undertake in its revised proposal to achieve the best possible outcomes for consumers.

Our draft decision

Our draft decision allows Jemena to recover $1,727.8 million ($nominal, smoothed) in revenue from consumers in the upcoming 2026–31 period. This is $260.7 million (or 13.1%) less than the $1,988.5 million that Jemena proposed. It is $347.6 million (or 25.2%) higher than the revenue we approved for Jemena in the current, 2021–26 period.[3]

Market factors, specifically rising inflation and interest rates, are driving higher revenues. In this draft decision we estimate 50% of the increase in revenue from period to period can be attributed to these external factors.

Our draft decision differs from Jemena's proposal in our assessment of the prudent and efficient capex and opex it will require in 2026-31 in order to continue to operate its network, and meet expected demand for its services, in accordance with its regulatory obligations. Based on the information before us, we are not satisfied that the magnitude of increases in expenditure Jemena has proposed are in line with prudent and efficient decision making. Our draft decision identifies areas in which further work by Jemena is needed to ensure its expenditure proposals meet these objectives. Our draft decisions on forecast expenditure are therefore placeholders subject to further supporting information being provided.

In this draft decision, we have not accepted Jemena's proposed net capex of $1,366.3 million ($2025-26) and have substituted it with an alternative estimate of $843.3 million (a 38% reduction). We have accepted Jemena's forecast expenditure where it provided sufficient evidence to support its prudency and efficiency. This is the case for the categories of fleet, property and other non-network capex. However, in this draft decision we have not accepted other elements of its proposed capex for which we found its proposal did not include sufficient quantitative evidence to support its forecasts.

These include replacement, augmentation and connections capex which together comprised the largest portion of its capex forecast.

We have not accepted Jemena's large uplift in replacement expenditure (repex). Our review of this element of its forecast, which included a review of major replacement projects, found

[3] In $2025–26 terms this is $41.5 million (or 2.7%) higher than the revenue we approved for Jemena.

that it lacked the detail and robust business cases needed to justify a major increase from its historical repex. Our draft decision includes guidance to Jemena on the further detail, support and justification that it should provide in its revised proposal if a further uplift is to be approved.

Jemena's expenditure proposal was driven by a projected doubling of demand, the highest forecast growth in demand amongst the Victorian distribution networks. We recognise Jemena is responding to a rapidly evolving energy system with growing demand from both traditional and large customer connections. However, our assessment of its proposal found insufficient justification for Jemena's proposed uplifts in growth driven expenditure, which were informed by what we consider to be overestimated increases in demand. These were forecast to arise from large, block loads for new connecting customers including data centres. We expect proposals to be based on evidence-based build ups to demand forecasts, and a transparent methodology that is open to testing and validation. Our draft decision encourages Jemena to present both a better supported forecast of demand driven capex in its revised proposal, including in particular a standardised approach to data centre connections capex.

Our draft decision does not accept Jemena's $615.2 million ($2025-26) opex forecast, for which we have substituted an alternative estimate of $564.7 million (a reduction of 8.2%). This is in part due to our lower forecast of demand, and therefore output growth. Our alternative estimate of forecast opex also excludes 6 of Jemena's 9 proposed step changes in opex, for CER and resilience related expenditure which we consider will already be adequately provided for through the base and trend components of our opex forecasting approach and do not require a further increase in opex. While we recognise a level of consumer support for Jemena's proposed expenditure on customer systems and expenditure in the 2026-31 period, we are similarly not satisfied on the information before us that Jemena's proposed step increase in opex for this program has been adequately justified. Our alternative estimate of total opex also includes a negative insurance step change, which was not proposed by Jemena, to ensure total forecast opex is prudent and efficient and to treat the significant insurance premium underspends as non-recurrent efficiency gains.

In looking beyond expenditure based solutions for the 2026-31 period, we encourage Jemena to do more to integrate its tariff strategy into its proposal. That is, it should include in its broader proposal (for example its forecast demand and proposed expenditure), further consideration of small consumers responding to the incentives for behaviour change provided by its tariffs.

Jemena's proposed TSS makes some progress on sending cost reflective price signals through retailers to shift usage out of peak times and into low-cost periods of the day. This includes proposing a solar soak (very low priced) period in the middle of the day for residential consumers. However, Jemena assumed limited consumer response to its small customer tariffs in its demand forecasts (other than those implicit through Jemena's use of historical trends and AEMO's electric vehicle charging forecasts). We are therefore not convinced that Jemena has done all it can to utilise tariffs to encourage efficient use of the network.

It is imperative for Jemena to use all the levers available to it, particularly tariffs, to optimise network utilisation. We consider that Jemena should engage further with stakeholders, including with retailers, to encourage take up of cost reflective tariffs and improve understanding of how tariff reform can complement (or mitigate) its proposed expenditure. It

should look to develop tariff trials aimed at managing flexible load and improve its long-run marginal cost calculations.

Jemena also has a role to play in enabling and supporting the roll out of new technologies, including kerbside electrical vehicle (EV) charging. While most EV charging occurs at home, kerbside AC chargers are seen by many stakeholders as a practical and cost-effective solution for high-density areas without off-street parking, offering convenience similar to home charging, and avoiding major grid upgrades. Third-party interest in using DNSP-owned infrastructure as a host for non-DNSP equipment is growing, and kerbside power poles owned by DNSPs have been identified as a potential host location for commercially provided EV charging infrastructure that will allow off peak charging of vehicles near the home. Commercial proponents of kerbside EV charging infrastructure are seeking to rent the use of DNSPs' kerbside poles for this purpose. Our draft decision is to classify a new, negotiated distribution asset rental service to support negotiation of access to Victorian DNSPs' kerbside poles for that purpose on terms that are fair, reasonable and cost reflective.

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 Jemena's proposal. Jemena 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 would allow Jemena to recover total revenue of $1,727.8 million ($ nominal, smoothed) from consumers from 1 July 2026 to 30 June 2031. This is $347.6 million more than Jemena's allowed revenue in the 2021–26 period in nominal terms. In the sections below, we briefly outline what is driving this increase in Jemena's revenue.

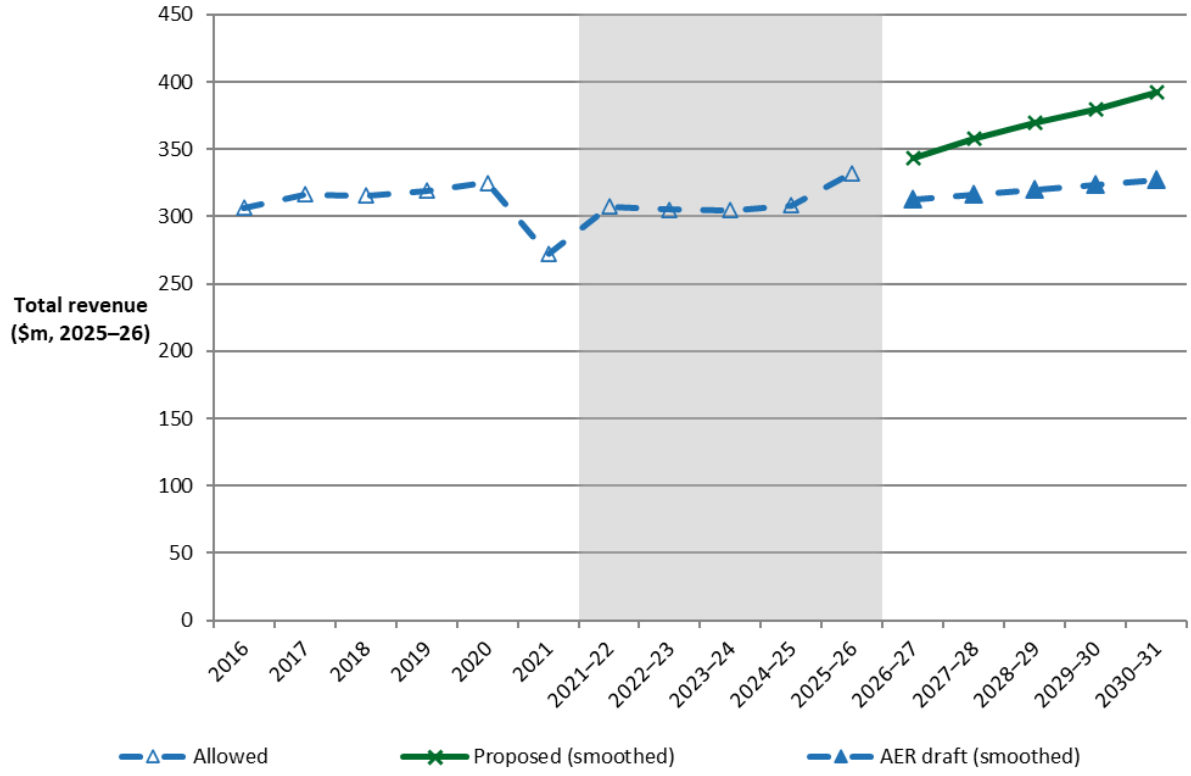
Our draft decision is $260.7 million lower than Jemena's proposal of $1,988.5 million in nominal terms. While slight increases in the rate of return and inflation have had some impact, the largest contributors to this difference are our draft decisions to reduce Jemena's proposed forecasts of capex and opex (by 27.5% and 8.2%, respectively). This reflects that we are not yet satisfied that all its projected increases are prudent, efficient and reflective of realistic expectations of demand. Jemena will have the opportunity in its revised proposal to address our concerns with its expenditure forecasts and, where it does so, final decision outcomes are likely to be different to those presented here.

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 in this section, we use 'real' values based on a common year (2025–26) that have been adjusted for the impact of inflation.

In real terms, this draft decision would allow Jemena to recover $1,600.1 million ($2025–26, smoothed) from consumers over the 2026–31 period. This is 2.7% higher than our decision for the current (2021–26) period. Changes in Jemena's revenue over time are shown in Figure 1, along with our draft decision smoothed revenue for the 2026–31 period compared to what Jemena proposed.

Figure 1 Changes in regulated revenue over time ($ million, 2025–26)



Source: AER analysis.
Note: For presentational purposes, the revenue for the half-year 2021 extension period has been doubled.

Figure 2 highlights the key drivers of the change in real terms between the revenue approved for Jemena for the 2021–26 period and in this draft decision for the 2026–31 period.

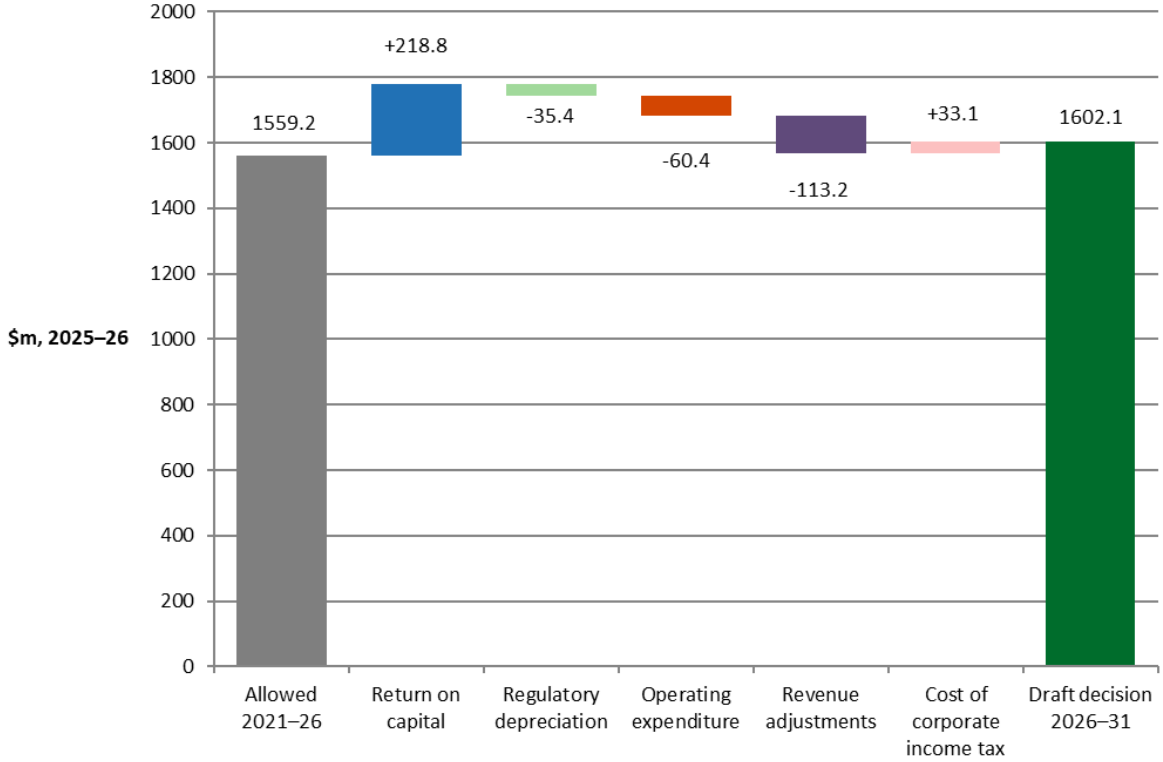
Our draft decision would provide for a return on capital that is $218.8 million (46.5%) higher than the 2021–26 period. Higher actual inflation for the current 2021–26 period and higher interest rates for the 2026–31 period would increase Jemena's return on its regulatory asset base (RAB) which, at the start of the 2026–31 period will be higher than anticipated in our last determination. Our draft decision also projects further RAB growth over the 2026–31 period driven by forecast capex, which in turn is increasing the return on capital.

The revenue approved in this draft decision also includes a net tax amount that is $33.1 million (87.1%) higher than the 2021–26 period. This is primarily due to higher capital contributions expected to be paid to Jemena by new, large customers connecting to its network compared to the 2021–26 period.

Partially offsetting these increases are:

- A lower return of capital (regulatory depreciation), which is $35.4 million (10.4%) lower than the 2021–26 period. This is due to a higher indexation of the RAB, mainly driven by a higher expected inflation value in the 2026–31 period.
- Forecast opex that is lower than the opex forecast we approved in the 2021–26 period.
- Revenue adjustments, which are $113.2 million lower than the 2021–26 period, mainly due to Efficiency Benefit Sharing Scheme (EBSS) and Capital Expenditure Sharing Scheme (CESS) penalty outcomes applied in this draft decision.

Figure 2 Changes in total revenue between 2021–26 period and 2026–31 period ($ million, 2025–26 unsmoothed)

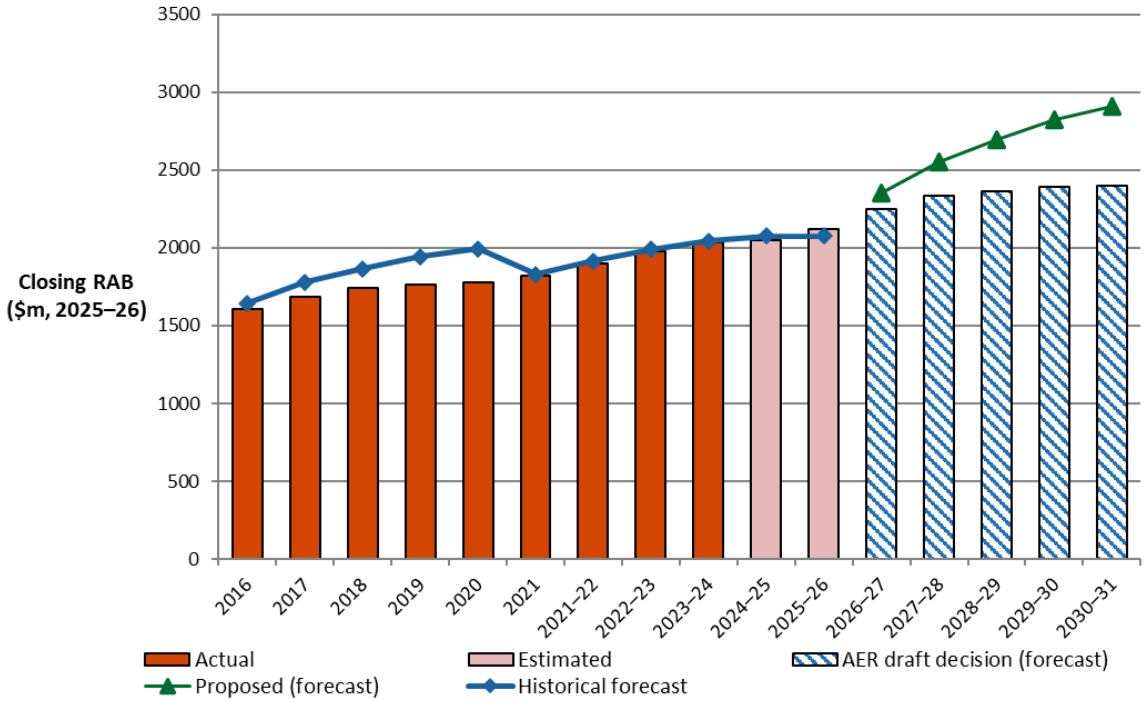


Source: AER analysis
Note: This comparison is based on converting nominal forecast amounts to real dollar terms using lagged consumer price index (CPI).

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

Figure 3 shows the value of Jemena's RAB over time in real terms. After a RAB increase of 16.7% over the 2021–26 period, our draft decision results in a forecast increase to the RAB of $273.0 million ($2025–26) or 12.9% over the 2026–31 period. This increase in the RAB is driven by a higher forecast capex over the 2026–31 period compared to the 2021–26 period. However, as shown in Figure 3, this increase is significantly lower than what Jemena proposed, reflecting our draft decision to reduce Jemena's proposed forecast capex.

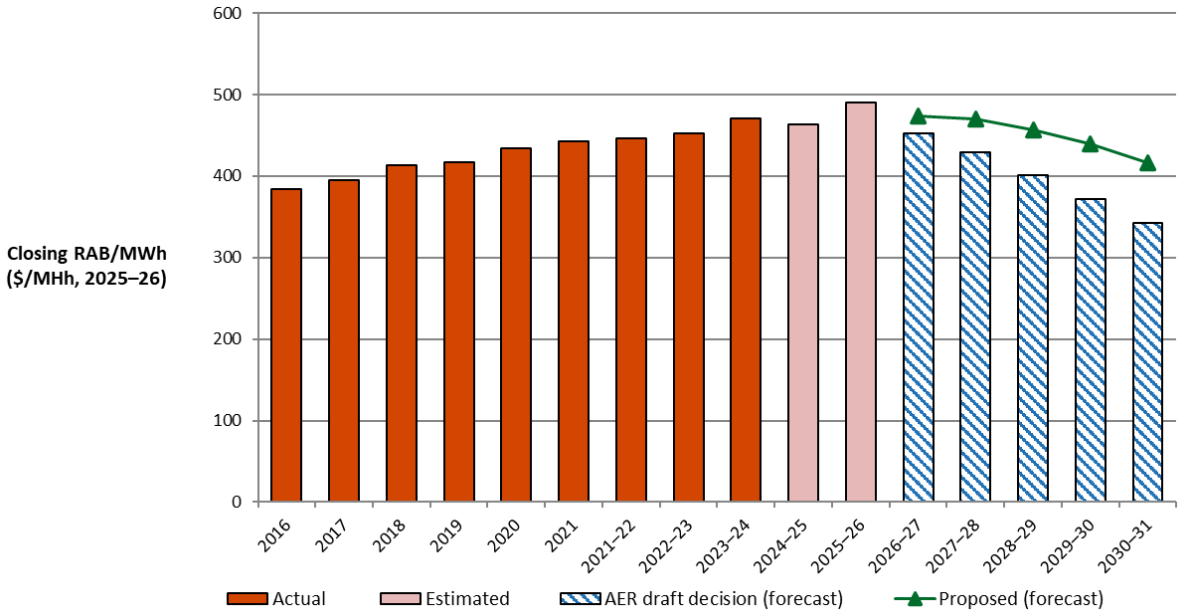
Figure 3 Jemena's RAB value over time ($ million, 2025–26)



Source: AER analysis.

Jemena's RAB per MWh is forecast to decline significantly over 2026–31 compared to the final year of the 2021–26 period, as can be seen in Figure 4. This is based on our draft decision alternative estimate of forecast energy delivered (MWh) and could change depending on the actual volume of energy delivered. While our alternative forecast of energy delivered is lower than Jemena's proposal due to our substitute of a lower amount of capex for data centre connections capex in the 2026-31 period, there is still significant consumption growth. This growth more than offsets the increase in the inflation adjusted real RAB ($2025–26). We consider efficient investment in, and efficient operation and use of, electricity services are important to minimise the required capital expenditure and the RAB.

Figure 4 Jemena's RAB per unit of energy consumption over time ($/MWh, 2025–26)



Source: AER analysis.

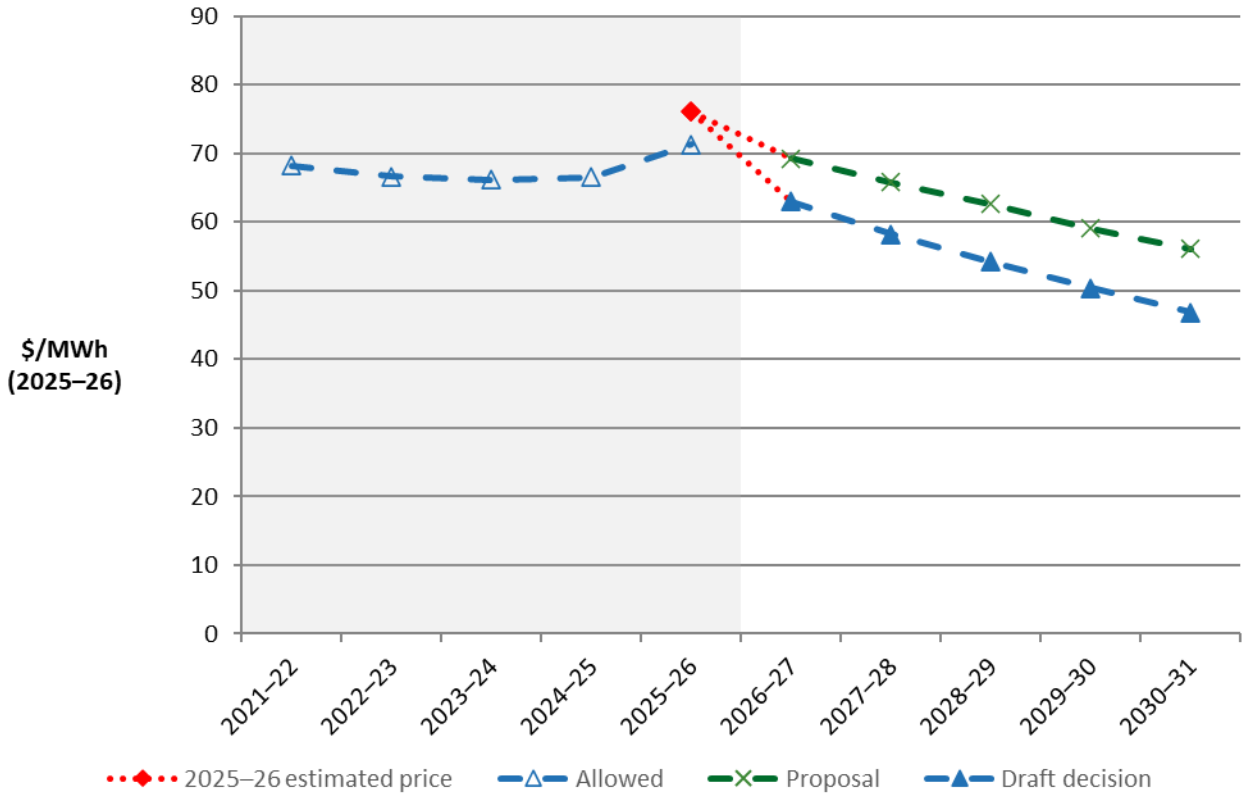
1.2 Expected impact of our draft decision on electricity bills

Jemena recovers its regulated revenue through distribution charges, set annually by reference to the TSS and pricing formulae approved by us as part of this decision.

For illustrative purposes only, we estimate the modelled impact of this draft decision would be a reduction to average distribution charges of around 38.5% in real terms by 2030–31 compared to 2025–26 levels, or an average real decrease of 9.3% per annum.[4] This estimate is subject to ongoing revenue adjustments and changes in consumer energy consumption during the 2026–31 period. Figure 5 compares this indicative draft decision price path for the 2026–31 period to the 2021–26 period, and what Jemena proposed.

4 The average decrease to indicative network charges of 9.3% ($2025–26) per annum reflects two components: 1) The draft decision smoothed revenue average decrease of 0.1% per annum ($2025–26); and 2) Our draft decision alternative forecast of energy delivered in Jemena's distribution network area, which is expected to increase on average by 10.0% per annum.

Figure 5 **Change in indicative distribution charges for 2021–26 to 2026–31 ($2025–26, $/MWh)**



Source: AER analysis.

Potential bill impact

Jemena's network charges make up around 29% of its residential consumers' electricity bills and 37% of its small business consumers' electricity bills.[5] Our draft decision also covers charges for revenue-capped metering services (that form part of alternative control services) and these costs are included in this estimated bill impact analysis. 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.[6] These sit outside the decision we are making here but will also continue to change throughout the period.

At the time of making this draft decision, we have used placeholder values for certain components of revenue such as the rate of return, expected inflation and some expenditure forecasts. We will make further updates for these values as part of our final decision. It is for this reason that we expect the total expected revenues approved in our final decision and resulting bill impacts to be different to this draft decision.

In nominal terms, which include the effect of expected inflation, the impact of this draft decision would be a decrease to the distribution component of consumers' electricity bills.

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5 Based on Victorian Default Offer, for a small business with a total annual use of 10,0000 kWh per year.

6 AEMC, *Data Portal,* *Trends in VIC supply chain components 2023/24*.

We estimate that the modelled impact of our draft decision on the average annual electricity bill for a retail customer in Jemena's network area, as it is today, would be:[7]

- a nominal reduction of $167 (10.2%) by 2030–31, or an average of $34 per annum for a residential consumer. This reflects:
  - a $146 reduction for distribution standard control services (SCS) charges
  - a $21 reduction for metering.
- a nominal reduction of $442 (11.9%) by 2030–31, or an average of $88 per annum for a small business consumer. This reflects:
  - a $417 reduction for distribution SCS charges
  - a $26 reduction for metering.

For our draft decision, we have adopted an alternative forecast of annual energy throughput which is lower than what Jemena proposed. This lower forecast has been used to estimate the bill impacts, noting that if the actual energy delivered over the 2026–31 period is lower than forecast it will result in higher bills, all else being equal, as Jemena is under a revenue cap. We discuss the sensitivity of employing alternative forecasts of energy throughput and its impact on indicative bills below.

Sensitivity of forecast energy delivered on bills

The impact of our draft decision and final decision on consumer bills is likely to change over the 2026–31 period. Jemena forecast the amount of annual energy delivered through its network will increase from 4,567 GWh in 2025–26 to 8,594 GWh in 2030–31, a significant increase of 4,206 GWh, or 88% over the period.

Stakeholders have highlighted the degree of uncertainty and risk around the demand forecasts proposed by Jemena, noting that if actual energy delivered over the 2026–31 period is less than forecast, distribution network tariffs and consumer bills would be higher, all else being equal.[8] This is because Jemena operates under a revenue cap and is therefore entitled to recover the revenue we determine, regardless of the actual energy delivered.

Our draft decision includes an alternative forecast of energy throughput which increases by 61% across the 2026–31 period, due to our decision to substitute a lower amount of data centre capital expenditures. While this increase in throughput is lower than Jemena's proposed increase of 88%, it still more than offsets the draft decision nominal revenue increase of 13% across the period.

Figure 6 shows the average annual bill for a residential consumer for a range of alternative energy delivered forecasts.

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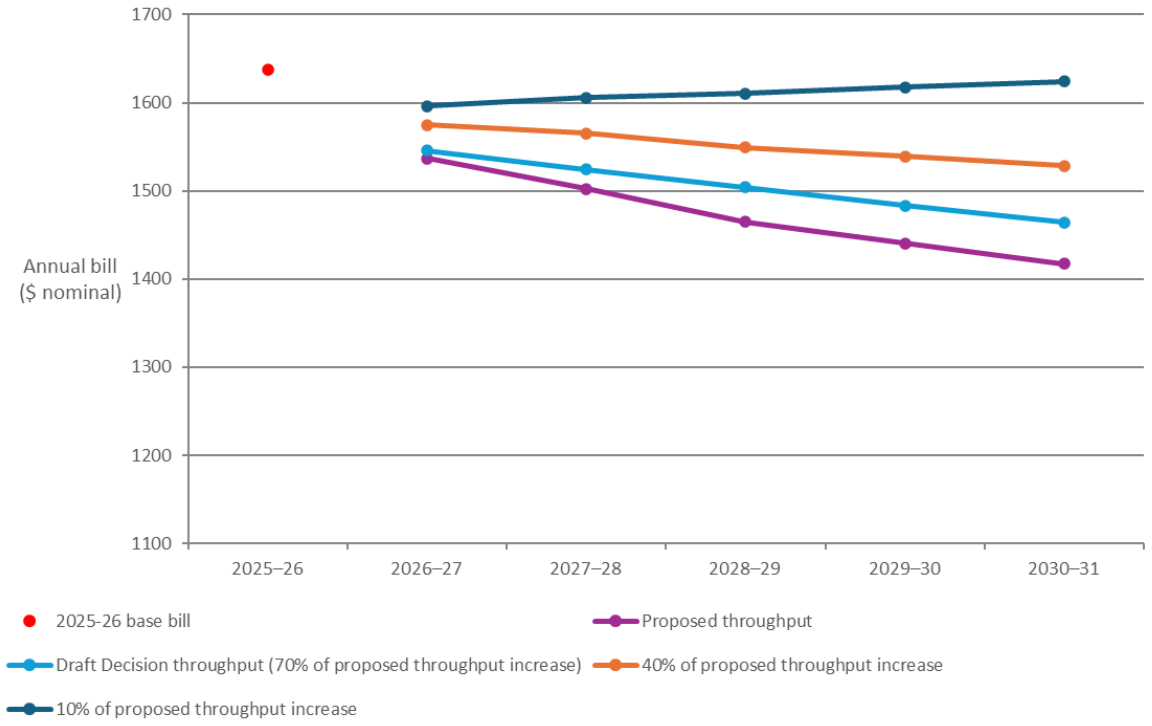
7 Our estimated bill impact is based on the typical annual electricity usage of 4,000 kWh and 10,000 kWh for residential and small business customers in Jemena's network area, respectively; Essential Services Commission, *Victorian Default Offer 2025–26, Final Decision Paper*, 21 May 2025, p. 5.

8 Sensitivity of energy delivered on bills was also discussed in our issues paper. AER, *Issues paper – Jemena electricity distribution determination 2026–31*, March 2025, pp. 7-10.

Figure 6 Sensitivity of energy delivered on annual residential bills



Source: AER analysis.

1.3 Consumer engagement

High quality consumer engagement is critical to development of a proposal that supports delivery of services and outcomes that reflect consumers' needs and preferences. Experience shows that proposals that genuinely reflect consumer preferences, and which also meet our expectations for assessing capex, opex, depreciation and tariff structure statements, are more likely to be largely or wholly accepted at the draft decision stage, creating a more effective and efficient regulatory process for all stakeholders.

The AER's Consumer Challenge Panel (CCP32) observed that that Jemena has met, and in many areas exceeded the expectations set out in our Better Resets Handbook and has significantly 'raised the bar' on its 2021-26 engagement program.[9]

Where consumers have been engaged on the outcomes Jemena seeks to achieve, our role is to now carefully assess the prudency and efficiency of the expenditure Jemena has submitted is necessary to deliver them.

The NER require us to consider the extent to which Jemena's proposed forecasts of opex and capex include expenditure to address the concerns of its end users, as identified by Jemena in the course of its engagement with end users or groups representing them. [10] This is one of several factors to which we must have regard in determining whether the total

9 CCP32 - *Submission - Jemena electricity distribution proposal 2026-31* - May 2025, p. 9.

10 NER, cll. 6.5.6(e)(5A), 6.5.7(e)(5A).

forecasts of opex and capex Jemena has proposed reasonably reflect prudent and efficient costs and a realistic expectation of future demand and cost inputs. [11]

We have heard that Jemena's consumers want electricity prices to be affordable, and tariff structures to be fair to different consumer groups such as solar and non-solar. We have also heard their support for prioritisation of investment in maintaining reliability and service levels and the resilience of Jemena's network to natural hazards or disasters. Jemena's consumers see a leading role for it in facilitating the transition to renewable energy sources and enabling and incentivising greater take up of CER.

Jemena has proposed significant uplifts in capex and opex relative to previous periods. Even where it is possible to say that its proposal is reflective of consumer views and preferences, this does not displace the AER's role in carefully testing and assessing the prudency and efficiency of proposed expenditure. Submissions have emphasised the importance of this scrutiny in ensuring desired outcomes are delivered at the lowest sustainable cost.[12]

Similarly, the effectiveness and outcomes of Jemena's engagement on its TSS, including its export tariff transition strategy[13], informed our assessment of proposed tariff structures. For example, we have had regard to information exchanged and feedback provided as part of consumer engagement when considering whether the structure of a tariff is reasonably capable of being understood by retail consumers, *or* of being directly or indirectly incorporated by retailers or intermediaries into contract terms offered to those consumers.[14]

11 NER, cll. 6.5.6(c), 6.5.7(c)(1).

12 Hon Lily D'Ambrosio MP - *Submission - Victorian electricity distribution proposals 2026-31* - June 2025; Origin Energy - *Submission - Victorian electricity distribution proposals 2026-31* - May 2025.

13 NER, cl. 6.8.2(c1)(2).

14 NER, cl. 6.18.5(i).

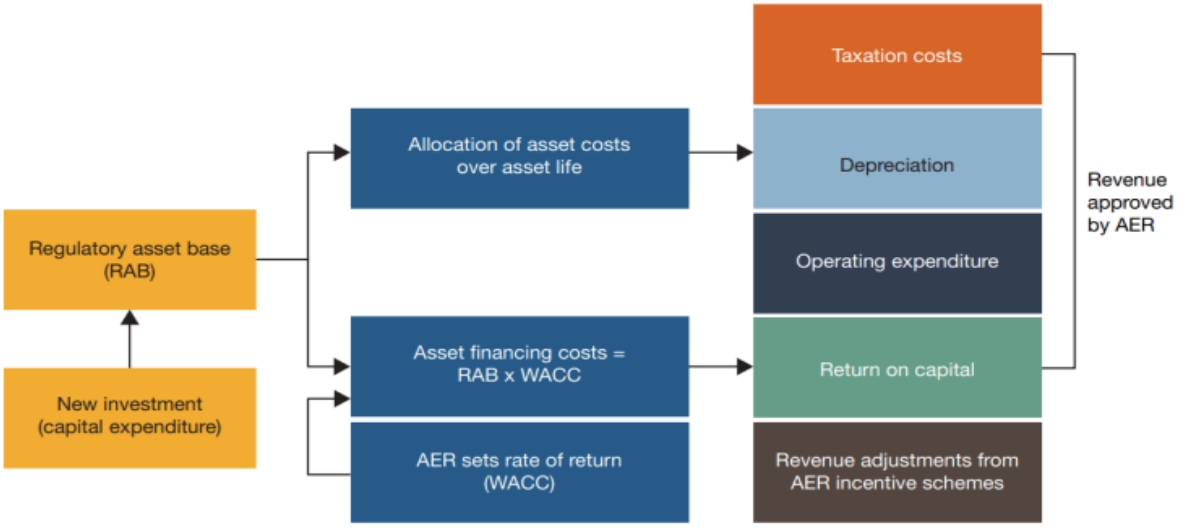
2 Key components of our draft decision on revenue

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 drives 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.

Under the NEL and NER, revenue is calculated using a 'building block' approach which looks at 5 cost components (see Figure 7):

- 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 7 The building block model to forecast network revenue



Source: AER.

Revenue smoothing

Our draft decision incudes a determination of Jemena's annual revenue requirement (ARR) (unsmoothed revenue) and annual expected revenue (smoothed revenue) across the 2026–31 period. The smoothed revenues we set in this draft decision are the amounts that Jemena will target for its annual pricing purposes and recover from consumers for the provision of SCS for each year of the 2026–31 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 Jemena's proposal. This is mainly driven by our reductions to Jemena's forecast capex and opex, estimated cost of corporate income tax and to its opening RAB as at 1 July 2026. Further reductions to revenues are due to our updates for external economic factors including a higher expected inflation rate, which reduces the regulatory depreciation building block.

Our draft decision allows for higher revenues than those determined in the 2021–26 period for the reasons discussed in section 1.1 of this Overview. In nominal terms, Jemena's unsmoothed revenue for the first year of the 2026–31 period (2026–27) is 5.2% lower than the approved revenue for the last year of the 2021–26 period (2025–26). It then increases by an average of 5.2% per annum over the remaining 4 years of the period.

We are mindful of the impact this revenue increase over the final 4 years of the period could have on network charges for Jemena's consumers. Consequently, our smoothed revenue profile reduces these increases and passes on the optimal reduction in 2026–27.

Our draft decision smoothed revenue is an initial revenue reduction of 2.7% ($ nominal) in 2026–27, followed by constant annual increases of 3.7% for the remaining 4 years (2027–28 to 2030–31). This smoothing profile results in a divergence between smoothed and unsmoothed revenue for 2030–31 of –3%, which is within our preferred range.

2.1 Regulatory asset base

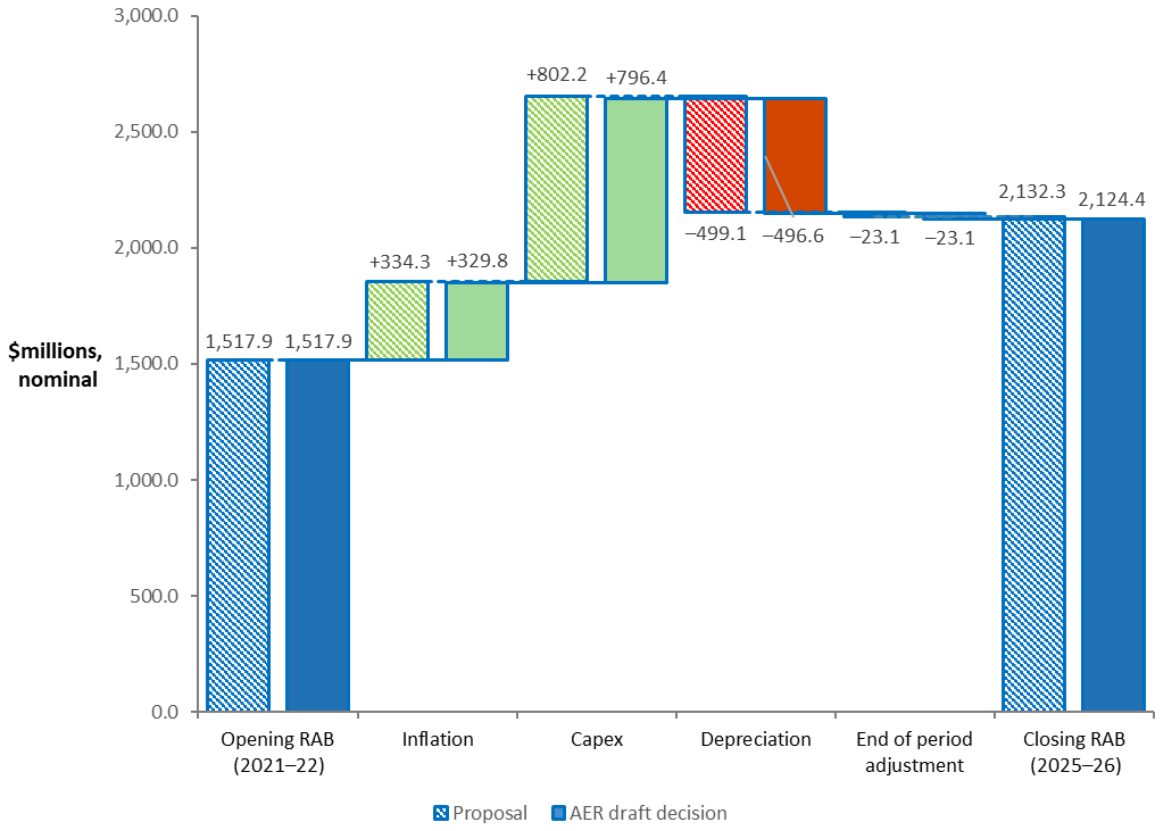
The RAB accounts for the value of regulated assets over time. To set revenue for a new regulatory period, we take the opening value of the RAB from the end of the last period and roll it forward year by year by indexing it for inflation, adding new capex and subtracting depreciation and other possible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

[15] Our draft decision expected revenues have not factored in 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.

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 $2,124.4 million ($ nominal) as at 1 July 2026. This value is $7.9 million (0.4%) lower than Jemena's proposed opening RAB value of $2,132.3 million. This reduction is largely due to the updates we made to the consumer price index (CPI) inputs for 2025–26 in the roll forward model (RFM) to reflect more up-to-date values. Figure 8 shows the key drivers ($ nominal) of the change in Jemena's RAB over the 2021–26 period compared to its proposal.

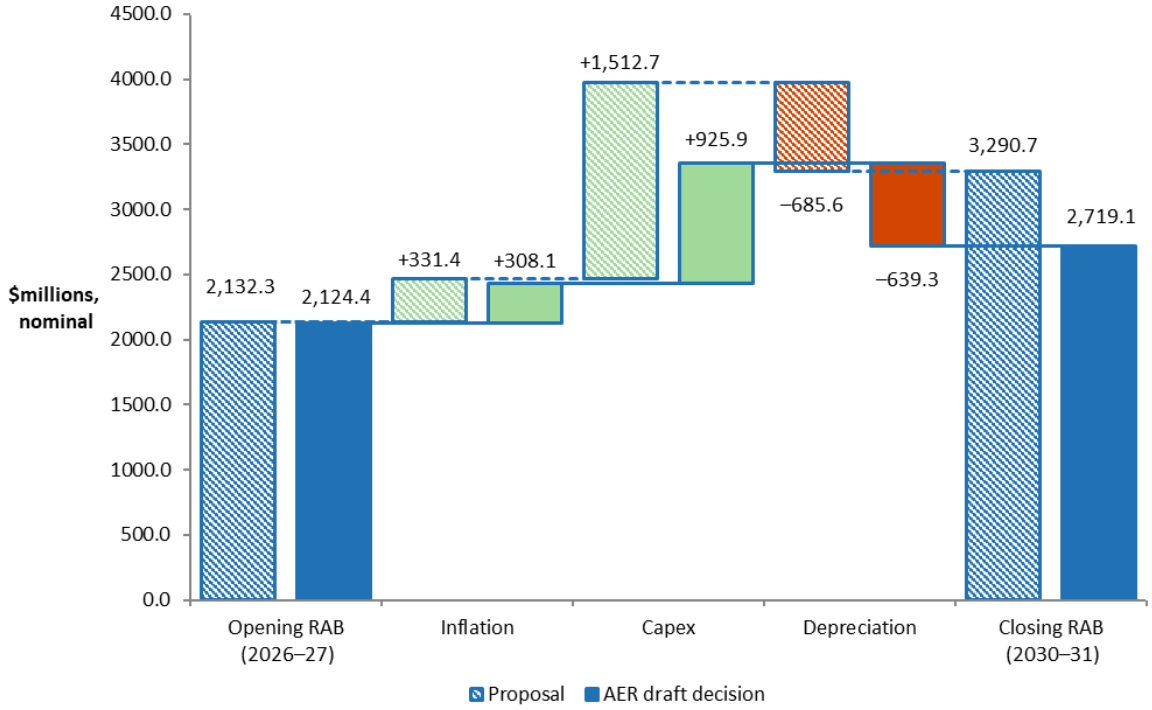
Figure 8 Key drivers of changes in the RAB over the 2021–26 period – proposal compared with AER's draft decision ($ million, nominal)



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 9 likewise shows the key drivers ($ nominal) of the change in Jemena's forecast RAB over the 2026–31 period compared to its proposal. We have determined a projected closing RAB of $2,719.1 million ($ nominal) as at 30 June 2031. This is $571.7 million (17.4%) lower than Jemena's proposed $3,290.7 million. This lower value is mainly due to our draft decision to reduce Jemena's forecast capex (attachment 2). It also reflects our draft decisions on the opening RAB as at 1 July 2026, forecast depreciation and the expected inflation rate.

Figure 9 Key drivers of changes in the RAB over the 2026–31 period – proposal compared with AER's draft decision ($ million, nominal)



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

2.2 Rate of return and value of imputation credits

The AER's 2022 Rate of Return Instrument (RORI) sets out the approach we will use to estimate the return on debt, the return on equity and the overall rate of return.[16]

The return each business is to receive on its RAB, known as the 'return on capital', is a key driver of proposed revenues. We calculate the regulated return on capital by applying a rate of return to the value of the RAB.

We estimate the rate of return by combining the returns of two sources of funds for investment: equity and debt. The allowed rate of return provides the business with a return on capital to service the interest rate on its loans and give a return on equity to investors.

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

[16] AER, *Rate of Return Instrument (Version 1.2)*, March 2024.

We are required by the NEL and NER to apply the RORI to estimate an allowed rate of return. For this draft decision, we have applied the 2022 RORI.[17]

Jemena's proposal adopted the 2022 RORI.[18] The 6.02% (nominal vanilla) rate of return in this draft decision is slightly higher than the 5.92% placeholder in the proposal, reflecting the net effect of a higher risk-free rate and a lower cost of debt.

Our calculated rate of return in Table 1 applies to the first regulatory year of the 2026–31 period. A different rate of return may apply for the remaining years of the period. This is because we will update the return on debt component of the rate of return each year, in accordance with the 2022 RORI, to use a 10-year trailing average portfolio return on debt that is rolled-forward each year. Hence, only 10% of the return on debt is calculated from the most recent averaging period, with 90% from prior periods.

Our draft decision accepts Jemena's proposed risk-free rate and debt averaging periods because they are consistent with the 2022 RORI.[19]

Table 1 Draft decision on Jemena's rate of return (nominal)

	AER's previous decision (2021-26)	Jemena's proposal (2026–31)	AER's draft decision (2026–31)	Allowed return over the regulatory control period
Nominal risk-free rate	1.65%	3.95%	4.25%[a]	
Market risk premium	6.10%	6.20%	6.20%	
Equity beta	0.6	0.6	0.6	
Return on equity (nominal post-tax)	5.31%	7.67%	7.97%	Constant (%)
Return on debt (nominal pre-tax)	4.64%[c]	4.75%	4.72%[b]	Updated annually
Gearing	60%	60%	60%	Constant (60%)
Nominal vanilla WACC	4.91%[c]	5.92%	6.02%	Updated annually for return on debt
Expected inflation	2.00%	2.50%	2.55%	Constant (%)

Source: AER analysis; AER, *Final decision – Jemena distribution determination 2021–26 – Attachment 3 – Rate of return*, April 2021, p. 6; Jemena, *2026-31 Electricity Distribution Price Review Regulatory Proposal – Attachment 08-01 – Annual revenue requirement for standard control services*, 31 January 2025, p. 4.

(a) Calculated using a placeholder averaging period of 20 business days ending 30 June 2025, which will be updated for the final decision.

(b) Calculated using a placeholder averaging period of 20 business days ending 30 June 2025, which will be updated for the final decision.

(c) Applied to the first year of the 2021–26 regulatory control period.

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

18 Jemena, *JEN 2026-31 Proposal*, 31 January 2024, p. 100.

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

Debt and equity raising costs

In addition to compensating for the required rate of return on debt and equity, we provide an allowance for the transaction costs associated with raising debt and equity. We include debt raising costs in the opex forecast because these are regular and ongoing costs which are likely to be incurred each time service providers refinance their debt. On the other hand, we include equity raising costs in the capex forecast because these costs are only incurred once and would be associated with funding the particular capital investments. Our approach to forecasting debt and equity raising costs is set out in more detail in our past determinations.[20] Jemena has proposed to use our approach to estimate debt and equity raising costs.[21]

Our draft decision is to apply a debt raising cost of 8.64 basis points per annum, which has been used to calculate the debt raising costs included in total forecast opex (see section 2.5).

We have updated our estimate for the 2026–31 period based on the benchmark approach using updated inputs. This results in equity raising costs of $6.26 million.

Imputation credits

Our draft decision applies a value of imputation credits (gamma) of 0.57, as set out in the 2022 RORI.[22] Jemena's proposal also adopted this value.[23]

Expected inflation

As set out in Table 2, our estimate of expected inflation is 2.55%. It is an estimate of the average annual rate of inflation expected over a 5-year period based on the outcome of our 2020 inflation review.[24] Jemena's proposal also adopted our approach.[25]

Table 2 Draft decision on Jemena's forecast inflation (%)

	Year 1	Year 2	Year 3	Year 4	Year 5	Geometric average
Expected inflation	2.60%	2.58%	2.55%	2.53%	2.50%	2.55%

Source: AER Analysis; RBA, *Statement on Monetary Policy*, August 2025, Table 3.1: Detailed Forecast Table. See https://www.rba.gov.au/publications/smp/2025/aug/outlook.html#table-3-1.

Our draft decision uses the Reserve Bank of Australia's (RBA) August 2025 Statement on Monetary Policy (SMP) which contains a consumer price index (CPI) forecast for the year-ending June 2027. This means the first year of the 2026–31 period is based on RBA forecasts and, thereafter, a linear glide-path from year two to the mid-point of the RBA's inflation target band of 2.5% in year 5. Figure 10 isolates the impact of expected inflation

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20 AER, *AER - Draft Decision Attachment 3 - Rate of return - Ergon Energy - 2025-30 Distribution revenue proposal,* 23 September 2024*,* pp. *4-6.*

21 Jemena, *JEN - CEG Att 06-02 Debt raising transaction cost report – 20250108*, 8 January 2025; Jemena, *JEN – Att 08-05M SCS PTRM – 20250131*, 31 January 2025.

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

23 Jemena, *JEN – Att 08-06M Rate of return model – 20250131*, 31 January 2025.

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

25 Jemena, *2026-31 Electricity Distribution Price Review Regulatory Proposal – Attachment 08-01 – Annual revenue requirement for standard control services*, 31 January 2025, p. 5.

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, higher inflation increases the return on capital but decreases regulatory depreciation.

Figure 10 Inflation components in draft decision revenue building blocks ($million, nominal)

Source: AER analysis

2.3 Regulatory depreciation (return of capital)

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

Our draft decision determines a regulatory depreciation amount of $331.2 million ($ nominal) for the 2026–31 period. This is a reduction of $23.0 million (6.5%) from Jemena's proposal of $354.2 million. This reduction is primarily due to our draft decision to reduce Jemena's forecast capex, which has reduced straight-line depreciation in the 2026–31 period. Our draft

decision to apply a lower opening RAB as at 1 July 2026, and a higher expected inflation rate for the 2026–31 period, has further reduced the regulatory depreciation building block.[26]

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 Jemena's RAB, which is used to determine the return on capital and return of capital (also known as regulatory depreciation) building block allowances. All else being equal, a higher capex forecast will lead to higher projected RAB value and higher return on capital and regulatory depreciation allowances.

Our draft decision is to not accept Jemena's forecast total capex of $1,366.3 million ($2025–26) for the 2026–31 period. Our alternative forecast is $843.3 million, which is 38% lower than Jemena's forecast. Table 3 sets out our draft decision for Jemena's forecast capex by capex category.

[26] Since RAB indexation is deducted from straight-line depreciation, a higher value of expected inflation also results in a lower regulatory depreciation.

Table 3 AER's draft decision by capex category ($ million, $2025–26)

Capex category	Jemena's proposal	AER's draft decision	Difference over capex category ($/%)	
Replacement	376.5	230.8	-145.7	-39%
Resilience	19.8	1.3	-18.4	-93%
Augmentation	223.9	147.8	-76.1	-34%
Connections	275.3	157.5	-117.8	-43%
ICT	114.7	92.7	-22.0	-19%
Property	17.4	17.4	0.0	0%
Fleet	33.6	33.6	0.0	0%
CER integration	84.5	17.9	-66.6	-79%
Non-network capex – other	1.4	1.4	0.0	0%
Capitalised overheads	222.2	160.3	-61.8	-28%
Total capex (less capital contributions)	**1,369.1**	**860.7**	**-508.4**	**-24.4%**
less Disposals	2.8	2.8	0.0	0.0%
Modelling adjustments		14.6	14.6	
Net capex	**1,366.3**	**843.3**	**-523.0**	**-27.5%**

Source: Jemena and AER analysis.
Notes: Numbers may not sum due to rounding. Jemena's augex proposal contains a $4.4 million innovation fund.

Figure 11 shows Jemena's historical capex trend, its proposed forecast for the 2026–31 regulatory control period, and our draft decision. As can be seen, Jemena proposed a material step up in the forecast period relative to the current period.

We also observe material overspends in the current period due to an expected increase in data centre investment late in the period. This may trigger an ex-post review in the 2031–36 regulatory determination. However, Jemena incurred total capex below its regulatory forecast for the current ex-post review period (2020 to 2023–24 regulatory years) and on this basis, the overspending requirement for an efficiency review of past capex is not satisfied.

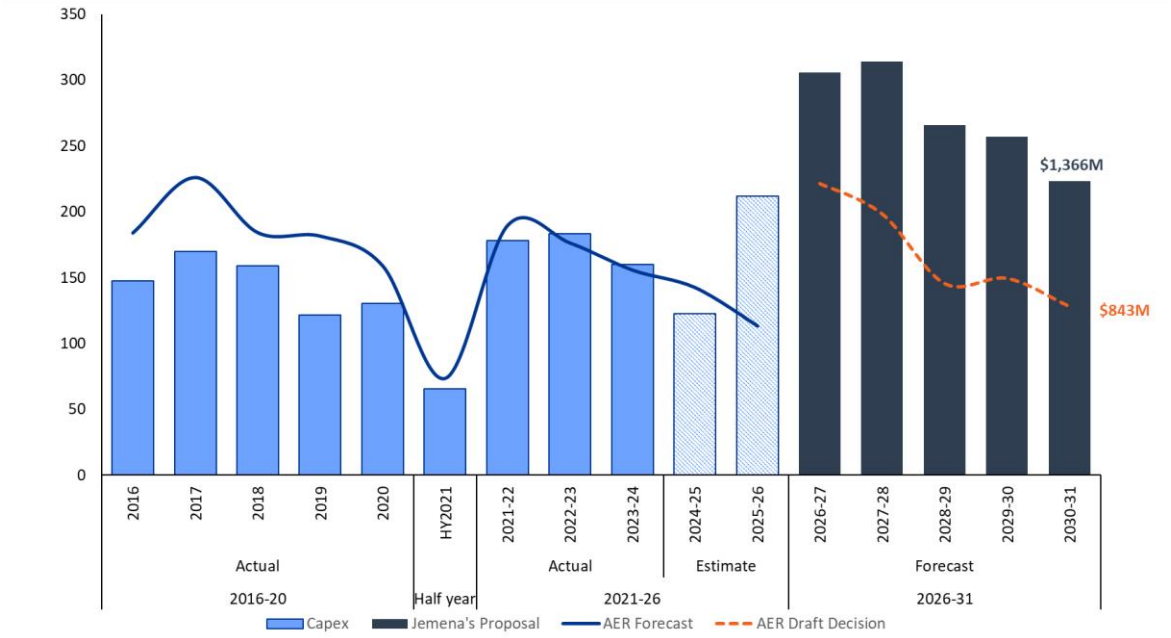
Figure 11 also shows that while our draft decision is a reduction to Jemena's forecast, it is a step up from Jemena's current period actual/estimates. We note that some of this step up is because:

- For replacement expenditure (repex), Jemena forecast an uplift of 73.6%. It attributed this to major spending for the first 3 years of the forecast regulatory period on replacements of primary assets in 3 of its major zone substations, pole reinforcements

and replacements, high voltage (HV) and low voltage (LV) crossarm replacements and feeder augmentation.

- For augmentation (augex), Jemena forecast an uplift of 15.7% ($223.9 million) from the current period's actual/estimated spending of $193.4 million. It noted that this is primarily driven by an increase in its demand forecast. The key drivers of demand driven augex for Jemena are increasing peak demand, population growth, increased data centre investment.
- For connections, Jemena forecast a significant uplift in major customers seeking to connect data centres for AI, cloud computing, big data analytics. These data centre investments have high capital contribution rates, with around 80% of the connection cost being paid by the data centre proponent. However, Jemena's connections forecast net of capital contributions was still 134% higher than the current period actual/estimate spend of $117.5 million.
- Jemena proposed to greatly expand its network's CER capabilities, an uplift of 413.6% ($84.5 million) compared to the 2021-26 period of $16.4 million. This is driven by programs such as enabling flexible exports and imports and enabling variable voltage control in zone substations to mitigate over-voltage risks.

Figure 11 Jemena's historical and forecast capex ($ million, $2025–26)



Source: Jemena and AER analysis.
Note: Capex is net of asset disposals and capital contributions.

Our alternative forecast of total capex of $843.3 million is a placeholder subject to further supporting information being provided in Jemena's revised proposal, including to address our concerns regarding Jemena's demand forecasts which impacts its connections and augex. We also seek further supporting information for its proposed repex.

Our top-down testing of Jemena's forecast capex informed the scope of our bottom-up review. We observe the following about Jemena's forecast capex at the top-down level:

- Its proposed total capex forecast is materially above (63.4%) current period actual/estimates.
- It has proposed a step up in the forecast for almost all capex categories, with a material step up in the largest components of capex of repex, augex and connections.
- It has materially overspent in the current period and forecasts a material step up.
- Its trend in the whole of network system average interruption frequency index (SAIFI) from 2015 to 2024 has remained low and stable, resulting in NEM-leading network reliability, but we acknowledge that performance in some areas of its network may vary.
- The repex modelling results indicate that Jemena has higher average unit rates and shorter replacement lives compared to the other 13 NEM DNSPs.

Given these top-down findings, we have undertaken a bottom-up review on most capex categories.

We have accepted Jemena's forecast expenditure where it provided sufficient evidence to support its prudency and efficiency. This is the case for forecast for the categories of fleet, property and other non-network.

However, we have not accepted Jemena's forecast in full, reducing it by 27.5%, because we found it did not provide sufficient quantitative evidence (as set out below) to support the material step up in the forecast.

As noted above, a key area of Jemena's expenditure proposal is driven by a projected doubling of demand, the highest growth in demand forecast amongst the Victorian distribution networks. However, our consultant, Baringa, identified significant concerns with Jemena's forecast of maximum demand. Baringa considered that Jemena's proposed demand forecast was opaque and lacking in necessary detail. For instance, it was unclear how the local-level forecast reconciles with the system-level forecast, and Baringa could not examine various proprietary, third-party algorithms in Jemena's modelling. Consequently, Baringa considered the forecast costs were likely to be overestimated. Having considered Baringa's advice and our own assessment of Jemena's demand modelling, we do not have sufficient confidence in Jemena's demand forecast. We do not consider Jemena has provided sufficient information for us to form our own alternative estimate. We are not satisfied of the prudence of Jemena's proposed uplift in connections and demand-driven augex which are justified on the basis of that demand forecast.

Another key area is the large uplift Jemena proposed in replacement expenditure (repex). As set out below, we consider Jemena has not satisfied us of this major increase from its historical expenditure. This is supported by our consultant's review of Jemena's proposal.

Our draft decision sets out reasons for our position including information gaps and/or lack of supporting information. We invite Jemena to address these issues in its revised proposal. We also encourage Jemena to engage with consumers about its revised proposal. We acknowledge the extensive consumer engagement that Jemena has undertaken on its capex proposal and would encourage it to continue to ensure that consumers' preferences are considered in its revised proposal.

For the areas of capex where Jemena did not demonstrate the prudency and efficiency of its forecast, we came to the following findings:

- *Repex* – We have not accepted Jemena's forecast repex. Overall, we consider Jemena's justification was lacking in detail, not supported by robust business cases, and did not justify a major increase from its historical expenditure. Our view was supported by our consultant EMCa through its review of major replacement projects and our own internal analysis. Our draft decision includes guidance to Jemena on the further detail, support and justification that it should provide in its revised proposal. We discuss this further in Attachment 2 of our draft decision.
- *Augex* – We have not accepted Jemena's proposed augex, primarily due our reductions to demand driven augex reflecting our assessment of its proposed demand forecast. Given the issues with Jemena's demand forecast and lack of a robust substitute, we relied on trending forward Jemena's actual/estimated demand driven augex for the current period to determine an alternate estimate for the draft decision. We have asked Jemena to provide a better supported demand driven forecast capex in its revised proposal. We have accepted parts of its non-demand driven augex.
- *Innovation* – We recognise the importance of innovation investment in supporting the energy transition and protecting consumers. There is a need for trials and pilots to test and explore new ideas, concepts and technology before committing to implementation of solutions and rolling these into business-as-usual activities. We also recognise Jemena sought to fund the majority (~70%) of its innovation capex and opex via grant funding, with $8.6 million ($4.4 million capex, $4.2 million opex) being the amount recovered through regulated revenues. However, we have not accepted Jemena's forecast in full. We have accepted the forecast for 3 projects as we found that these projects align with the criteria for ex-ante innovation projects. We found that the majority of the 15 projects did not satisfy those criteria, especially the criteria that the project be innovative. We substituted the $4.4 million capex innovation fund with $1.7 million for the 3 projects we consider satisfy the criteria.
- *Connections* – We have not accepted Jemena's proposed connections capex, driven by our assessment of Jemena's demand forecast. Our analysis indicated that Jemena's maximum demand forecasts are higher than have been substantiated in its proposal, and that its modelling required more transparency in order to test the conclusions drawn from it. Our alternative forecast accepts in-flight data centre projects connections and 50% of proposed enquiry to offer projects. We have not included future growth projects. We have asked Jemena to present a standardised approach to data centre connections projects capex in its revised proposal.
- *ICT* – We do not accept Jemena's forecast ICT in full. We are not satisfied 4 of the 14 proposed non-recurrent projects are prudent and/or efficient. We have considered the information Jemena has provided in its proposal and analysis provided by EMCa that the benefits Jemena has assumed will result from the customer education program are not likely to be as high as it has suggested, and that ICT replacement activities such as the proposed expenditure for end-user computing should already be in recurrent expenditure. Further, while Jemena's Market Interface Technology Enhancement is prudent, we are not satisfied on the information available that it is efficient, so we have substituted a lower amount. Our alternate estimate for recurrent ICT is also lower than

Jemena's forecast, and is based on average actual expenditure, rather than Jemena's proposal which included unusually high estimates of expenditure yet to be in incurred in 2024–25 and 2025–26.

- *CER integration* – We have not accepted all of Jemena's proposed CER integration capex. For 2 of the projects, we consider that, based on the information provided and EMCA's assessment, Jemena has incorrectly quantified the benefits of the proposed programs (voltage and power quality management, and data visibility and analytics) and that its forecast expenditure is not prudent and efficient. While Jemena's flexible services program appears reasonable and similar to those proposed by other DNSPs, our assessment is that an alternative estimate of related capex based on benchmarks with the other NSPs is likely more appropriate.
- *Resilience* – Our alternative capex forecast does not include Jemena's proposed expenditure for flood-risk asset relocation, for which it has to date provided insufficient supporting information and analysis. We have, however, accepted Jemena's community resilience capex investment as its supporting material demonstrated the prudency and efficiency of its proposed expenditure.

Our draft decision on Jemena's capital expenditure is set out in Attachment 2.

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 Jemena's total regulated revenue requirement.

Our draft decision is to not accept Jemena's total opex forecast of $615.2 million,[27] including debt raising costs, for the 2026–31 regulatory control period.[28] This is because our alternative estimate of $564.7 million is materially different ($50.4 million, or 8.2% lower) than Jemena's total opex forecast proposal. Therefore, we consider that Jemena's total opex forecast does not reasonably reflect the opex criteria.[29]

Our draft decision, which is less than Jemena's proposed total opex forecast, is:

- $63.0 million (10.0%) lower than the opex forecast we approved in our final decision for the 2021–26 regulatory control period
- $93.4 million (19.8%) higher than Jemena's actual (and estimated) opex in the 2021–26 regulatory control period.

In Figure 12 we compare our alternative estimate of opex to Jemena's proposal for the next regulatory control period. We also show the forecasts we approved for the last two regulatory control periods and Jemena's actual and estimated opex over these periods.

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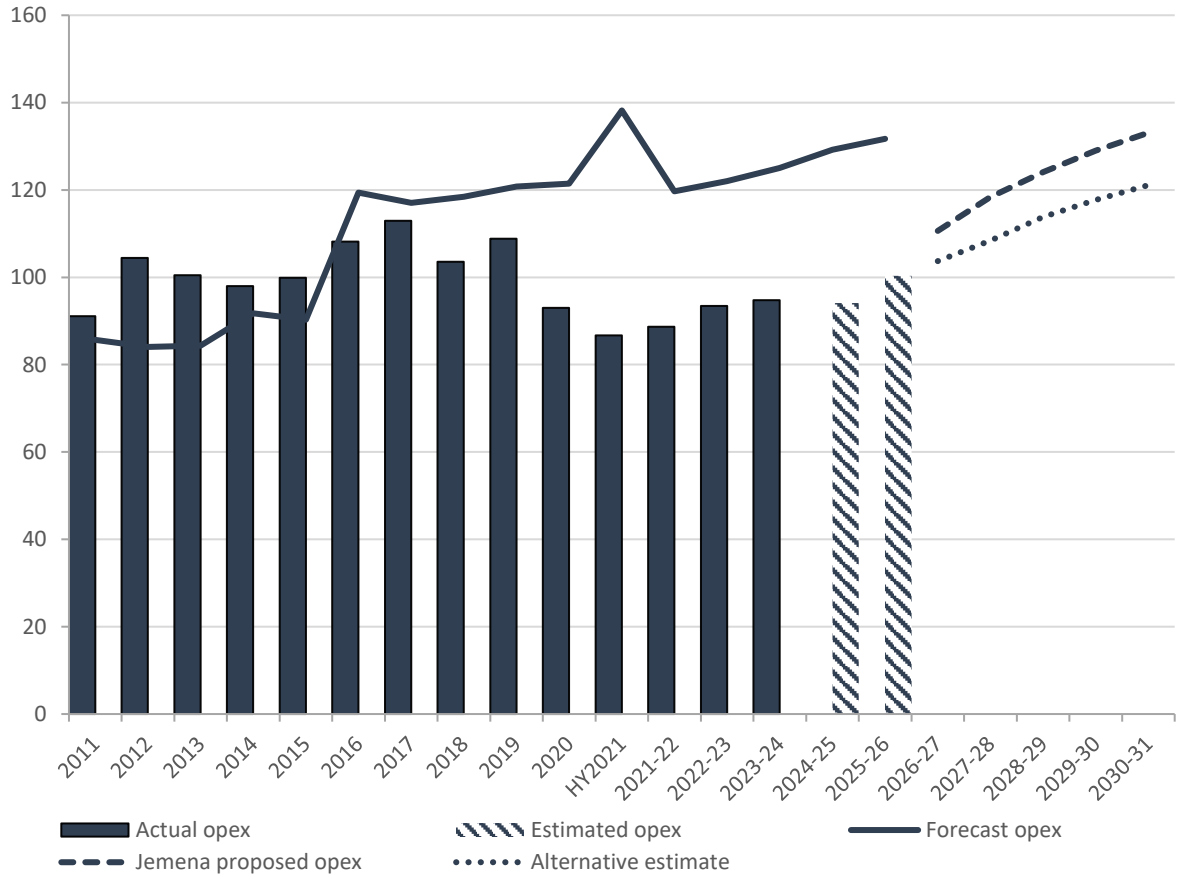
27 All dollars are in this section are in $2025–26 terms, unless otherwise stated.

28 Jemena, *JEN - Attachment 06-03M SCS Opex model.*

29 NER, cl. 6.5.6(c)–(e).

Figure 12 Historical and forecast opex ($million, 2025–26)



Source: Jemena, *Attachment 06-03M – SCS Opex Model*, January 2025; AER, *AER – Jemena distribution determination 2021–26 – PTRM – 2024–25 RoD update*, August 2024; AER, *AER – Jemena distribution determination – 2020 return on debt update – PTRM*, October 2019: AER, *AER Final decision – Jemena 2011 to 2015*, August 2013; AER analysis.

Our lower alternative estimate of total opex, which is the basis of the opex draft decision, is primarily due to our alternative estimate not including, or including lower alternative estimates for the 9 step changes Jemena proposed.

Other key differences between Jemena's opex proposal, which we have not accepted, and our draft decision are that we have:

- Included a negative insurance step change, which was not proposed by Jemena, to ensure that our forecast opex satisfies the opex criteria, and to treat the significant insurance premium underspends in the current period as non-recurrent efficiency gains, reducing forecast opex by $27.2 million.
- Applied slightly lower output growth forecasts compared to Jemena's, reducing forecast opex by $8.4 million.

In our final decision, we will update our alternative estimate of total opex to reflect actual opex for 2024–25, as well as make other mechanical updates. Our draft decision is based on the estimate of base year opex included in Jemena's initial proposal because actual data for 2024–25 was not available at the time the proposal was submitted.

2.6 Corporate income tax

Our determination of the total revenue requirement includes the estimated cost of corporate income tax for 2026–31 period. Under the post-tax framework, this amount is calculated as part of the building blocks assessment using our PTRM.

Our draft decision determines an estimated cost of corporate income tax amount of $75.9 million ($ nominal) for Jemena over the 2026–31 period. This is a reduction of $59.9 million (44.1%) from Jemena' proposal of $135.8 million.

This reduction is primarily due to the lower forecast of customer capital contributions to be paid to Jemena in our draft decisions, following our reductions to forecast connections capex. A lower capital contribution reduces the estimated taxable income for Jemena which in turn reduces the estimated cost of corporate income tax.

Proposals from Victorian DNSPs have brought into focus the impact that the tax treatment of large customer capital contributions, paid in respect of new, large customer connections, has on the revenue recovered from all consumers. We have identified a potential alternative approach drawing on our determinations for the current period. This relates to the DNSPs' proposals that net tax liability arising from capital contribution from large, embedded generators be included in connection charges payable by the generator itself. This approach was proposed to reduce the cross-subsidy paid by the wider consumer base to large, embedded generator connections, and reduce exposure to forecasting risk associated with these connections. Our draft decisions encourage Victorian DNSPs to consider the possibility of extending of this model to other large connecting customers (e.g. data centres) in their revised proposals.

2.7 Revenue adjustments

Our calculation of total revenue for 2026–31 will include adjustments for the expenditure incentive schemes that were applied to Jemena as part of our determination for the current, 2021-26 period.

These include:

- A revenue decrement of $4.4 million ($2025–26) under the EBSS. This is lower than Jemena's proposed adjustment (benefit) of $21.0 million ($2025–26). This difference reflects adjustments we have made to account for non-recurrent costs and efficiency gains, as well as the latest updates for inflation and the weighted average cost of capital.
- A revenue decrement of $25.53 million ($2025–26) under the CESS. This is lower than Jemena's initially proposed positive increment of $3.13 million ($2025–26). When Jemena submitted its proposal, it had applied to reopen its 2021-26 capex forecast. Jemena's initial calculation of CESS outcomes assumed that application would be successful, such that the difference between its actual expenditure and the approved forecast for 2021-26 would be reduced. In July 2025, Jemena withdrew its application. Our draft decision therefore replaces its assumed CESS benefit with a decrement.

Our draft decision on the application of the CESS and EBSS to Jemena's expenditure in the new, 2026-31 period is discussed in section 3.

Our draft decision also includes an allowance of $2.5 million ($2025–26) under the Demand Management Innovation Allowance Mechanism (DMIAM), to fund research and development in innovative demand management projects that have the potential to reduce long-term network costs.[30] Consistent with the design of the DMIAM, this allowance is included in Jemena's total revenue as a positive revenue adjustment rather than as part of forecast opex or capex. Any unspent portion of the allowance can therefore be returned to consumers as one of the permitted adjustments to revenue under the NER.[31] This is not the case for unspent capex or opex, as Jemena has suggested in the case of its proposed innovation allowance for the 2026-31 period. We consider the NER only allows for adjustments in limited circumstances[32] and we do not accept that the businesses can apply a 'use it or loss it' mechanism to select elements of their capex and opex proposals.

2.8 Uncertainty mechanisms

Our distribution determination for Jemena 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 2026–31 period there are several additional mechanisms under the NER that may operate to increase or decrease those charges.

A distribution business may apply to us seeking the recovery of additional costs incurred during a regulatory period, if certain predefined exogenous events occur as specified in either the NER or in its respective revenue determination.

Cost pass through events

There are 3 prescribed cost pass through events (regulatory change event, service standard event and tax change event) that apply to all Victorian DNSPs under the NER. In addition to the NER prescribed pass through events, Jemena proposed the same 5 nominated cost pass through events approved as part of our determination for the current period (an insurance coverage event; insurer credit risk event; terrorism event; natural disaster event; and retailer insolvency event). Our draft decision is to accept these again.

Contingent projects

Contingent projects are usually significant network augmentation projects that are reasonably required to be undertaken to achieve the capex objectives. However, unlike other proposed capex projects, the need for the project within the regulatory control period and the associated costs are not sufficiently certain. Consequently, expenditure for such projects does not form a part of the total forecast capex that we approve in this determination. Such projects are linked to unique investment drivers and are triggered by defined events. The occurrence of the trigger event must be probable during the relevant regulatory control period. The cost of the projects may ultimately be recovered from consumers in the future if certain predefined conditions (trigger events) are met.

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30 We developed and implemented the DMIAM under cl. 6.6.3A of the NER: AER - Demand management innovation allowance mechanism - 14 December 2017.

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

32 NER, cl. 6.4.3(a)(6).

Our draft decision does not accept Jemena's proposed contingent projects. The projects themselves appear reasonable at a high-level. However, despite providing amended triggers in response to requests, Jemena has not provided trigger events are reasonably specific and capable of objective verification. If this is resolved in its revised proposal, we will then assess whether the contingent project would reasonably address the trigger event. The full detail on our draft decision on Jemena's contingent projects is set out in Appendix B of Attachment 2.

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 incentive schemes that will apply to Jemena in the 2026–31 period is as follows.

Efficiency benefit sharing scheme (EBSS)

Our draft decision is that the EBSS will continue to apply to Jemena in 2026-31. This provides a continuous incentive to pursue efficiency improvements in main SCS 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. Our draft decision on the EBSS is set out in Attachment 5.

Capital expenditure sharing scheme (CESS).

Our draft decision is that the CESS will continue to apply to Jemena in 2026-31. 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. Jemena proposed excluding connections and innovation capex from the CESS in the 2026-31 period.

We updated the CESS in August 2025 and introduced a mechanism which takes into account the potential for change in volumes of connections. As the volumetric adjustment is a new addition to the CESS, we are seeking Jemena's views in the revised proposal on how this adjustment can be applied.

For innovation, we have maintained our position to not have category specific exclusions beyond the volumetric adjustment for connections. However, we note that Jemena may voluntarily reduce its CESS reward if it does not undertake innovation capex.

Our draft decision on the CESS is set out in Attachment 6.

Customer service incentive scheme (CSIS)

Our draft decision is to not apply a CSIS to Jemena in 2026-31.

The CSIS is designed to encourage electricity distributors to engage with their consumers, identify (through consumer engagement) the customer services their consumers want improved, and then set targets to improve those services based on their consumers' preferences. Unlike other Victorian DNSPs, Jemena did not have a CSIS in the current, 2021-26 period. We identified issues with Jemena's consultation on its proposed introduction of a CSIS for the 2026-31 period, and the application of feedback from its Energy Reference Group. We do not consider Jemena's proposed CSIS is compliant with the requirements of the scheme. Our draft decision on the CSIS is set out in Attachment 9.

We will instead apply the telephone answering parameter and introduce the new connections parameter of the customer service component of the STPIS. We have observed that CSIS proposals are becoming increasingly homogenised, static, and informed by diminished consumer engagement. While our assessment of the new connections parameter is ongoing, we consider that formalising customer service incentive parameters under the STPIS could be a better outcome for consumers. A new connections parameter in the STPIS aligns with our focus on ensuring that DNSPs comply with their obligations to provide timely and transparent connections and reflects consumers' apparent willingness to pay for the improved services relating to connections.

Service target performance incentive scheme (STPIS)

Our draft decision is that the STPIS will continue to apply to Jemena in 2026-31. 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 to reduce costs at the expense of service quality. Once improvements are made, the benchmark performance targets will be tightened in future years. Our draft decision on the STPIS is set out in Attachment 7.

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

Our draft decision is that both the DMIS and DMIAM will continue to apply to Jemena in 2026-31. The DMIS provides DNSPs 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 on the DMIS and DMIAM are set out in Attachment 8.

Victorian F-Factor incentive scheme

The F-factor scheme is prescribed by the Victorian Government's 'F-factor scheme order 2016' to reduce the risk of fire starts by network assets.[33] We will continue to adopt our current approach to give effect to the outcomes of the scheme as an 'I-factor' component within the price control formula. Our draft decision on the Victorian f-factor incentive scheme is set out in Attachment 10.

[33] Victoria Government Gazette, G 51, 22 December 2016, p. 3239

4 Network pricing

Our determination for Jemena separates the regulated direct control services it provides into different classifications, which determines how it will recover the cost of providing those services through network prices. We set out our proposed approach to the classification of distribution services to be provided by Victorian DNSPs in 2026–31 in our Framework and Approach paper in July 2024,[34] at which time services were classified as either:

- Standard control services: those that can only be provided by the relevant DNSP, and are common to most, if not all, of a DNSP's customers. The costs of providing these services are captured in the building block revenue determination discussed in the previous sections of this Overview and shared between all consumers.
- Alternative control services: those that can only be provided by the relevant DNSP but will only be required by some of its customers, some of the time; or services that can be purchased from the relevant DNSP, but which can also—or have the potential to be—purchased from a competing provider. The cost of providing alternative control services is recovered from users of those services only.

However, since the Framework and Approach was published[35], we consider a material change of circumstances has arisen that justifies the classification of a new, negotiated distribution service.

DNSPs can rent their assets to third parties (e.g. office space rental, pole and duct rental for hanging telecommunication wires etc) for use separately or in addition to essential electricity connection and supply services. These distribution asset rental services are currently not classified (i.e. unregulated), meaning the AER has no role in setting the price or non-price terms offered to customers. When a DNSP's annual unregulated revenues from shared assets are expected to be greater than 1 % of its total smoothed annual revenue requirement for that regulatory year, a portion of any revenue earned by a DNSP from distribution asset rental is returned to consumers in accordance with the Shared Asset Guideline.

Our Framework and Approach paper for Victorian DNSPs for the 2026-31 regulatory control period did not classify, or mention, distribution asset rental services in any form.

Since then, we have seen widespread emergence of third-party interest in using DNSP-owned infrastructure as a host for non-DNSP equipment for EV chargers. Particular concerns have been raised by prospective providers of commercial kerbside EV chargers with their ability to rent DNSPs' kerbside poles as a 'host' for EV charging infrastructure. These include the variability, transparency and fairness of access pricing and other terms of pole leasing arrangements. Together these have created a step change in the materiality and relevance of accessing distribution asset rental services (as distinct, for example, from access to

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34 AER – *Final Framework and Approach – Victorian electricity distribution determinations 2026-31* – July 2024, Appendix A.

35 AER - Final Framework and Approach - Victorian electricity distribution determinations 2026-31 - July 2024

regulated connection or metering services) for use by third parties as a host for EV charging infrastructure, and competitive delivery of kerbside EV charging in particular.

Our draft decision is to classify the following new negotiated distribution service, to support negotiation of access to Victorian DNSPs' kerbside poles for that purpose on terms that are fair, reasonable and cost reflective:

> "Distribution asset rental: Rental of distribution assets (e.g. poles) to third parties for the installation of electric vehicle (EV) chargers or associated hardware".

The effect of the negotiated service classification for this service would be that, for the 2026-31 period, negotiations between Jemena and parties seeking access to this new distribution service would be subject to:

- a Negotiating Framework, which sets out the procedure to be followed during negotiations between the DNSP and any person who wishes to receive a negotiated distribution service, as to the terms and conditions of access to the service, and
- Negotiated Distribution Service Criteria (NDSC), setting out the principles that guide negotiations,

both of which will be approved as part of our distribution determination for that period.

We received no submissions on proposed Negotiating frameworks, or our proposed Negotiated distribution service criteria, in our consultation on these earlier this year. We are mindful, however, that service classifications at the time of that consultation did not include any negotiated services. We therefore welcome any new submissions on the proposed frameworks and criteria now that this has changed. We discuss this further in Attachment 17 to this draft decision.

4.1 Control mechanisms for standard and alternative control services

In our Framework and Approach paper for the 2026–31 period, our proposed approach was to continue to apply the same control mechanisms as we applied in the current, 2021–26 period:

- A revenue cap for standard control services
- A revenue cap for metering services (as alternative control services)
- A price cap for ancillary network services, public lighting and metering exit fees (as alternative control services).

Our draft decision confirms this approach.

In our issues paper, we requested feedback on whether the current form of control mechanism for standard control services remained appropriate, and whether criteria for a change to the control mechanism had been satisfied. Our draft decision is that the above control mechanisms will continue to apply in the 2026–31 period. We discuss this further in Attachment 12 to this draft decision.

4.2 Tariff structure statement

Our draft decision is not to approve Jemena's proposed TSS. We consider Jemena is making some progress on network tariff reform within the constraint of aligning with Victorian Government preference that customers move only gradually to cost reflective tariffs over the 2026–31 regulatory period. However, we encourage Jemena to further consider how well-designed network tariffs charged to retailers can shift future demand growth out of peak periods and into low/minimum demand periods.

Jemena's proposed TSS for the 2026–31 period is its third since the Australian Energy Market Commission's (AEMC) *Distribution Network Pricing Arrangements* rule change in 2014 that introduced the TSS framework.[36] The TSS is also Jemena's first since the AEMC's 2021 *Access, pricing and incentive arrangements* rule change that allowed for two-way pricing.[37] Together these rule determinations introduced several reforms to distribution pricing, including to progress cost reflective pricing and to support more CER into the network.

Principally, we assess TSSs against the requirements of the NER and NEL, including the pricing principles and other applicable requirements of the NER.[38] We are also required to make our decisions in a manner that will or is likely to contribute to the achievement of the NEO.[39] For TSSs, we consider the NEO elements of price and achievement of jurisdictional emissions reduction targets to be most relevant.

With each TSS we also look at how a DNSP has responded to the reforms mentioned above. A TSS informs use of the network by:

- providing clear price signals of what it costs to use the network at different times, allowing consumers (or their retailers) to make informed decisions to better manage bills
- transitioning tariffs to greater cost reflectivity while requiring DNSPs to explicitly consider the impacts on retail customers, by engaging with consumers, consumer representatives and retailers in developing network tariff proposals
- managing future expectations by setting out the DNSP's tariff approaches for a set period.

A TSS 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.[40] 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.

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36 AEMC, *Rule Determination – National Electricity Amendment (Distribution Network Pricing) rule 2014,* November 2014.

37 AEMC, *Rule Determination – National Electricity Amendment (Access, Pricing and Incentive Arrangements for Distributed Resources) rule 2021,* August 2021.

38 NEL, s. 16(2). The national electricity objective is in NEL, s. 7.

39 NEL, s. 16(1)(a).

40 NER, cl. 6.18.1A(a).

While an indicative pricing schedule must accompany the TSS, the tariff levels for each tariff for each year of the 2026–31 period are not set as part of this determination.[41] Tariff levels for the regulatory year commencing 1 July 2026 will be subject to a separate, annual approval process beginning in May 2026, after we have made our final revenue determination in April 2026.[42]

4.2.1 Our draft decision and its context

Network tariff reform enables DNSPs to charge retailers in a manner which more closely reflects the cost of providing electricity network capacity to end-use customers and can support the energy transition currently underway. Where price signals are passed through, and consumers are well placed to respond to these price signals, appropriately structured tariffs can enable growth in the value consumers derive from their CER, and in the number of consumers with 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.

Our draft decision does not approve Jemena's proposed TSS. We accept that some individual elements comply with the pricing principles and contribute to achievement of the NEO. However, we strongly encourage Jemena to reflect further on its assumption of no consumer response to its small customer tariffs in its demand forecasts[43] (other than those implicit through Jemena's use of historical trends and the Australian Energy Market Operator's (AEMO) EV charging forecasts). Our draft decision emphasises the capacity for well-designed network tariffs to shift future demand growth out of peak periods and into low/minimum demand periods. We have provided examples in Attachment 13 of consumers responding to price signals. We therefore consider Jemena should engage further with its stakeholders, including retailers, on the benefits of assigning small customers to cost reflective tariffs in the 2026–31 period where they can benefit from low off-peak rates, and should further explain the interrelationship between its tariff strategy and its wider proposal (including proposed expenditure) in its revised proposal overview.[44]

Jemena is also required to make the following changes in its revised TSS for the elements that we do not approve in this draft decision. These changes are required for Jemena's TSS to achieve compliance with the NER pricing principles and contribute to the achievement of the NEO:

- recalculate its long-run marginal costs to reflect at least a 10-year time horizon
- include further information to justify its proposed basic export level[45] of 1 kWh/day for its proposed export tariff and large battery/storage tariff

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41 NER, cl. 6.8.2(d1).

42 This will occur pursuant to obligations in cl. 6.18.2 and cl. 6.18.8 of the NER.

43 Jemena Electricity Networks, *Response to information request IR010: TSS and LRMC*, May 2025, p. 5.

44 NER, cl 6.8.2(c1)(1)(v).

45 The basic export level is the amount of electricity that a customer will be able to export to the grid at no cost (NER cl. 11.141.12). The basic export level must apply for a 10-year period (that is, for two regulatory periods). This may be adjusted within the 10-year period.

- include further description of its proposal to continue to discount the residential time-of-use tariff relative to the flat tariff to ensure stakeholder understanding of its proposal
- include complete network bill impact analysis for all customer types and tariff changes
- provide further information explaining small business tariff assignment policies to comply with the requirements in NER cl. 6.18.1A(a)(2)
- clearly set out both the structure, charging periods and assignment of the proposed battery tariff and provide indicative prices.
- provide further information on assignment policies for the proposed site-specific tariffs and how price levels will be set, to comply with the requirements in NER cl. 6.18.1A(a)(2) and NER cl. 6.18.1A(a)(5)
- consider how to incorporate new type 9 meters in the TSS.

We note that Jemena, along with the other Victorian DNSPs, also retained its opt-out assignment to cost reflective tariffs for *new* small customers with smart meters, and its largely opt-in assignment to cost reflective tariffs for *existing* customers. For example, Jemena will not assign existing small customers to cost-reflective tariffs except in limited circumstances. This includes if they own EV fast chargers or upgrade to 3-phase. Customers with EV fast chargers will not be able to opt-out to single rate tariffs. Jemena's assignment policies align with the Victorian Government's preference that customers move only gradually to cost reflective tariffs over the 2026-31 regulatory period.[46] This means that despite having near-universal smart meter penetration in Victoria since 2013, the proportion of consumers in Victoria on cost reflective pricing is low compared to other jurisdictions in the NEM.

Encouraging opt-in to, and a response to, cost reflective tariffs is particularly important for Jemena given the significant increase in demand it forecast from the electrification of transport and gas[47] and the potential for this to contribute to demand-driven capex in future regulatory periods. Jemena's (and the other Victorian distributors') view that small customers are not responding to price signals warrants further consideration and response by Jemena. It does not align with outcomes from trial tariffs, or experience emerging from other distributors. We continue to consider that tariffs are an important, low-cost tool distributors can use to mitigate expenditure in the 2026–31 period and future periods by incentivising use of existing network capacity.

To progress tariff reform under its assignment polices and encourage customers to opt-in to a more cost reflective tariff, Jemena proposed to continue to discount its residential time-of-use tariff by 1% each year. This would mean that by 2031 this tariff would be on average 10% cheaper than Jemena's non-cost reflective single rate/flat residential tariff. Jemena also progressed tariff reform by proposing a solar soak (low priced) period in the middle of the day for its residential time-of-use tariff, an opt-in export (two-way) tariff for residential customers, a battery tariff and site-specific tariffs for its high voltage and sub-transmission customers.

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46 Hon. Lily D'Ambrosio MP, *Submission on Victorian Electricity Distribution Proposals 2026-31*, June 2025.

47 Jemena Electricity Networks, *JEN 2026-31 proposal*, January 2025, p.72.

However, we are not convinced that Jemena has done all it can to utilise and/or encourage take-up of cost reflective tariffs to encourage efficient use of the network. We therefore encourage Jemena to develop a tariff trial aimed at more flexible load, like EVs or home batteries, whose response to network price signals could help mitigate the need for network investment. We consider that improved calculations of long-run marginal costs will assist Jemena's tariffs to better reflect efficient costs and improve the accuracy (and therefore effectiveness) of its price signals, particularly to manage flexible loads. Given the changes currently taking place in the energy sector there exists opportunity for Jemena (and other distributors) to further refine and develop their long-run marginal cost methodologies.

In addition to the required changes, we encourage Jemena to consider making minor improvements in its revised TSS. This includes considering introduction of an open controlled load tariff with 24-hour supply availability.

In Attachment 13, we describe in further detail the reasons for our decision and the changes that we consider necessary for us to approve Jemena's TSS proposal, as well as the changes we encourage Jemena to make.

4.3 Alternative control services

4.3.1 Public lighting

Public lighting services include the provision, construction and maintenance of public lighting assets. This includes technologies such as energy-efficient light emitting diode (LED) luminaires and emerging public lighting technologies such as smart-enabled luminaires.

Our draft decision is to not accept Jemena's public lighting proposal because although we consider some aspects of Jemena's proposal are reasonable there are others where we consider adjustments are required. For the draft decision we have made several updates to the public lighting model inputs, including reducing the volumes of smart lighting cells to reflect stakeholder feedback. We also increased the pole inspection rate and extended the photoelectric cell replacement cycle as we did not consider these were sufficiently justified. Jemena should provide further evidence to justify these inputs in its revised proposal. In addition to this, we also included more mechanical changes related to updated inflation and labour escalator inputs.

This results in prices for 2026–27 that are on average 8.6% lower compared to Jemena's proposal.

We also encourage Jemena to consult further with its stakeholders to inform its revised proposal. This consultation should include matters such as funding options for its accelerated LED rollout and further refining its smart lighting services. These issues reflect those raised in a submission to our issues paper from the Victorian Greenhouse Alliances. We discuss this further in Attachment 14 to this draft decision.

4.3.2 Metering services

Metering services include maintenance, reading, data services, and the recovery of capex related to metering assets. Unlike other jurisdictions in the NEM, Victorian DNSPs are the monopoly providers of most metering services to small customers. This includes smart meters which are a part of regulated alternative control services.

Our draft decision is not to accept Jemena's metering proposal. For the draft decision we have made several adjustments to the forecast capex and opex. This includes reducing labour costs and an opex step change associated with an inspection-led proactive replacement of meters approaching end of life and redirecting this expenditure to higher volumes of age-based proactive replacement, reflecting the greater efficiencies opportunities we think are available under this approach. We have also removed components of the proposed IT capex and communications capex that we do not consider are justified and made more mechanical changes related to updated inflation, rate of return and labour escalators inputs. Overall, this results in a decrease of $24.8 million ($nominal) or 16.5% from Jemena's proposed total revenue requirement for metering of $150.1 million ($nominal, smoothed) for the 2026–31 period.

We encourage Jemena to consider the metering adjustments that we have made in this draft decision and respond to these in its revised proposal and to incorporate the outcomes of any further stakeholder engagement it undertakes.

The reasoning behind our draft decision is outlined further detail in Attachment 15.

5 Constituent decisions

In accordance with clause 6.12.1 of the NER, this draft decision on the distribution determination that will apply to Jemena for the 2026-31 period is predicated on the following constituent decisions.

Table 4 Constituent decisions

NER cl. 6.12.1	Constituent decision
6.12.1(a)	The AER's draft decision is that the classification of services set out in Attachment 11 will apply for the 2026-31 regulatory control period.
6.12.1(b)(1)	The AER's draft decision is not to approve the annual revenue requirement as set out in the building block proposal for each regulatory year of the 2026–31 regulatory control period. The AER's draft decision on the annual revenue requirement for each regulatory year of the 2026–31 regulatory control period is set out in Attachment 1.
6.12.1(b)(2)	The AER's draft decision is to approve the commencement and length of the regulatory control period as proposed in the building block proposal. The AER's draft decision is that the regulatory control period will commence on 1 July 2026, and that the length of the regulatory control period will be 5 years (concluding 30 June 2031).
6.12.1(b1)	The AER did not receive a request for an asset exemption under clause 6.4B.1(a)(1) of the NER and therefore has not made a decision in accordance with clause 6.12.1(b1).
6.12.1(c)	Acting in accordance with clause 6.5.7(d) of the NER, the AER's draft decision is not to accept the total of the forecast capital expenditure for the regulatory control period that is included in the current building block proposal. The AER's draft decision therefore sets out an alternative estimate of the total of the required net capital expenditure of $843.3 million ($2025-26). The reasons for the AER's decision are set in Attachment 2.
6.12.1(c1)	The AER's estimate of the total of the required capital expenditure under cl. 6.12.1(c) (above) does not include expenditure for a restricted asset.
6.12.1(d)	Acting in accordance with clause 6.5.6(d) of the NER, the AER's draft decision is not to accept the total of the forecast operating expenditure for the regulatory control period that is included in the current building block proposal. The AER's draft decision therefore sets out an alternative estimate of the total of the required operating expenditure of $564.7 million ($2025-26). The reasons for the AER's decision are set in Attachment 3.
6.12.1(d1)(1)	The AER's draft decision is that the following proposed contingent projects described in the current regulatory proposal are not contingent projects for the purposes of the distribution determination, for the reasons set out in Attachment 2: • Tullamarine cluster

<table>
<tr><th>NER cl. 6.12.1</th><th>Constituent decision</th></tr>
<tr><td></td><td>• Heidelberg

The AER has therefore not made decisions under clauses 6.12.1(d1)(2) and 6.12.1(d1)(3) for these proposed contingent projects. The reasons for the AER's decision are set out in Attachment 2.</td></tr>
<tr><td>6.12.1(e)</td><td>The AER's draft decision on the allowed rate of return for the 2026–27 regulatory year is 6.02% (nominal vanilla) for the reasons set out in Section 2.2 of this Overview. The rate of return for the remaining regulatory years of the 2026–31 period will be updated annually because our decision is to apply a trailing average portfolio approach to estimating debt which incorporates annual updating of the allowed return on debt.</td></tr>
<tr><td>6.12.1(e1)</td><td>The AER's draft decision on the allowed imputation credits for each regulatory year or the regulatory control period is 0.57.</td></tr>
<tr><td>6.12.1(f)</td><td>The AER's draft decision on the regulatory asset base as at the commencement of the 2026–31 regulatory control period, in accordance with clause 6.5.1 and schedule 6.2 of the NER, is $2,124.4 million ($nominal). The reasons for the AER's decision are set out in Attachment 1.</td></tr>
<tr><td>6.12.1(g)</td><td>The AER's draft decision on the estimated cost of corporate income tax for the 2026–31 regulatory control period, in accordance with clause 6.5.3, is $75.9 million ($ nominal). The reasons for our draft decision are set out in Attachment 1 and the amount for each regulatory year of the 2026–31 regulatory control period is set out in the table below.
<table>
<tr><th>($ million, nominal)</th><th>2026–27</th><th>2027–28</th><th>2028–29</th><th>2029–30</th><th>2030–31</th><th>Total</th></tr>
<tr><td>Tax payable</td><td>63.0</td><td>28.0</td><td>25.9</td><td>30.9</td><td>28.7</td><td>176.4</td></tr>
<tr><td>Less: value of imputation credits</td><td>35.9</td><td>15.9</td><td>14.7</td><td>17.6</td><td>16.4</td><td>100.6</td></tr>
<tr><td>Net cost of corporate income tax</td><td>27.1</td><td>12.0</td><td>11.1</td><td>13.3</td><td>12.3</td><td>75.9</td></tr>
</table>
</td></tr>
<tr><td>6.12.1(h)</td><td>The AER's draft decision is not to approve the depreciation schedules submitted by Jemena. The AER has therefore determined depreciation schedules in accordance with cl. 6.5.5(b). The regulatory depreciation amount approved in this draft decision is $331.2 million ($ nominal) for the 2026–31 regulatory control period. The reasons for the AER's decision are set out in in Attachment 1.</td></tr>
<tr><td>6.12.1(i)</td><td>The AER's draft decision on how applicable incentive schemes are to apply to Jemena in the 2026-31 period is:

• Version 2 of the Efficiency Benefit Sharing Scheme will apply. Our reasons are set out in Attachment 5.

• Version 4 of the Capital Expenditure Sharing Scheme will apply. Our reasons are set out in Attachment 6.</td></tr>
</table>

NER cl. 6.12.1	Constituent decision
	• Version 2.0 of the Service Target Performance Incentive Scheme (including the customer service component) will apply. Our reasons are set out in Attachment 7. • the Demand Management Incentive Scheme will apply. Our reasons are set out in Attachment 8. • the Demand Management Innovation Allowance Mechanism will apply. Our reasons are set out in Attachment 8. • the Customer Service Incentive Scheme will not apply. Our reasons are set out in Attachment 9.
6.12.1(j)	The AER's draft decision is that all other appropriate amounts, values and inputs are as set out in this draft decision, including in supporting models and attachments.
6.12.1(k)	The AER's draft decision on the form of the control mechanism(s) (including the X factor) for standard control services is, in accordance with the Framework and Approach Paper, a revenue cap. The AER's draft decision on the formulae that give effect to the revenue cap form of control mechanism is set out in Attachment 12.
6.12.1(l)	The AER's draft decision on the form of the control mechanism(s) for alternative control services is, in accordance with the Framework and Approach Paper: • For metering services – a revenue cap. • For ancillary network services public lighting, and metering exit fees – a price cap. The AER's draft decision on the formulae that give effect to those control mechanisms is set out in Attachment 12.
6.12.1(m)	The AER's draft decision on how Jemena is to demonstrate compliance with the control mechanisms above is: • For Standard Control Services: maintain distribution unders and overs mechanisms through the annual pricing model templates. • For Alternative Control Services – metering services revenue cap: maintain metering services unders and overs account through the annual pricing model templates. • For Alternative Control Services – price caps: demonstration that proposed prices are compliant with price caps through the annual pricing model templates. These mechanisms and processes to demonstrate compliance are set out in Attachment 12.
6.12.1(n)	The AER's draft decision is that the following additional pass through events are to apply for the regulatory control period in accordance with clause 6.5.10: • Insurance coverage event • Insurer's credit risk event

NER cl. 6.12.1	Constituent decision
	• Terrorism event • Natural disaster event • Retailer insolvency event. These events have the definitions set out in Attachment 4.
6.12.1(n1)	The AER's draft decision is not to approve the TSS proposed by Jemena. The reasons for our draft decision are set out in Attachment 13.
6.12.1(o)	The AER's draft decision is that the negotiating framework as proposed by Jemena is to apply for the regulatory control period. The reasons for the AER's decision are set out in Attachment 17.
6.12.1(p)	The AER's draft decision is that the Negotiated Distribution Service Criteria set out in Attachment 17 will apply to Jemena for the regulatory control period. The reasons for the AER's decision are set out in Attachment 17.
6.12.1(q)	The AER's draft decision on the policies and procedures for assigning retail customers to tariff classes, or reassigning retail customers from one tariff class to another, is set out in Attachment 13.
6.12.1(r)	The AER's draft decision is that depreciation for establishing the regulatory asset base as at the commencement of the following regulatory control period (as at 1 July 2031) is to be based on forecast capital expenditure. The reasons for the AER's decision are set out in Attachment 1.
6.12.1(s)	The AER's draft decision on how Jemena is to report to the AER on its recovery of designated pricing proposal charges for each regulatory year of the regulatory control period, and on the adjustments to be made to subsequent pricing proposals to account for over or under recovery of those charges, is through the unders and overs mechanism. This is to be demonstrated through the use of the annual pricing model templates and is set out in Attachment 12.
6.12.1(t)	The AER's draft decision on how Jemena is to report to the AER on its recovery of jurisdictional scheme amounts and pass through of jurisdictional scheme refund amounts for each regulatory year of the regulatory control period, and on the adjustments to be made to subsequent pricing proposals to account for over or under recovery of those amounts, is through the unders and overs mechanism. This is to be demonstrated through the use of the annual pricing model templates and is set out in Attachment 12. This draft decision applies to each jurisdictional scheme under which Jemena has jurisdictional scheme obligations within the operation of this draft decision.
6.12.1(u)	The AER's draft decision is that a variant of the connection policy as proposed by Jemena, set out in Attachment 16, is to apply to Jemena for the regulatory control period. The reasons for the AER's decision are set out in Attachment 16.

NER cl. 6.12.1	Constituent decision
Other constituent decisions	
	In accordance with section 16C of the *National Electricity (Victoria) Act 2005*, the NEL, the NER and the 'f-factor scheme order 2016',[48] the AER's draft decision is to apply the f-factor incentive payments/penalties as a part of the 'I-factor' adjustment to the calculation of the total annual revenue requirement using the formulae in Attachment 12.

Notes: In this table, 'regulatory control period' means the period 1 July 2026 to 30 June 2031 determined in accordance with clause 6.12.1(b)(ii).
References in this table to 'the current proposal', 'the building block proposal', 'the current building block proposal' and to documents submitted or matters proposed by Jemena are to the regulatory proposal and TSS submitted by Jemena on 31 January 2025.
References in this table to 'the Framework and Approach Paper' are to the AER – *Final Framework and Approach – Victorian electricity distribution determinations 2026-31* – July 2024 published by the AER on 31 July 2204.

Source: References in this table to where detailed constituent decisions can be found are to documents and models published on the AER's website.

[48] http://www.gazette.vic.gov.au/gazette/Gazettes2016/GG2016G051.pdf, Victoria Government Gazette, G 51 22 December 2016, p. 323

6 List of submissions

	Date
AGL	June 2025
AER Consumer Challenge Panel (CCP32)	May 2025
Electric Vehicle Council	May 2025
Hon Lily D'Ambrosio MP	June 2025
Jemena Energy Reference Group	May 2025
Origin Energy	May 2025
Save Our Surroundings Riverina	May 2025
Victorian electricity distribution businesses	May 2025
Victorian Greenhouse Alliances	May 2025

7 Shortened forms

Term	Definition
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARR	Annual revenue requirement
Augex	Augmentation expenditure
BAU	Business as usual
Capex	Capital expenditure
CCP32	Consumer Challenge Panel, sub-panel 32
CER	Consumer Energy Resources
CESS	Capital expenditure sharing scheme
CPI	Consumer price index
CSIS	Customer service incentive scheme
DMIAM	Demand management innovation allowance mechanism
DMIS	Demand management incentive scheme
DNSP	Distribution Network Service Provider
EBSS	Efficiency benefit sharing scheme
EV	Electric Vehicle
GWh	Gigawatt hour
ICT	Information and communication technology
LED	Light emitting diode
MWh	Megawatt hour
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
Opex	Operating expenditure
PTRM	Post-tax revenue model
RAB	Regulatory asset base

Term	Definition
RBA	Reserve Bank of Australia
Repex	Replacement expenditure
RFM	Roll forward model
RORI	Rate of return instrument
SCS	Standard control services
SMP	Statement on monetary policy
STPIS	Service target performance incentive scheme
TOU	Time-of-use
TSS	Tariff structure statement
TUOS	Transmission use of system charges
WACC	Weighted average cost of capital