Final Decision

Jemena Electricity Distribution Determination (1 July 2026 to 30 June 2031)

Overview

April 2026

AUSTRALIAN ENERGY REGULATOR

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Version	Date	Pages
1	30 April 2026	55

List of attachments

This Overview forms part of the Australian Energy Regulator's (AER's) final decision on the distribution determination that will apply to Jemena for the 2026–31 period. It should be read with all other parts of the final decision.

A number of issues were settled at the draft decision stage or required only minor updates, so that detailed attachments to this final decision are not needed. Where this is the case, our draft decision reasons form part of this final decision. The final decision attachments have been numbered consistently with the equivalent attachments to our draft decision.

The final decision includes the following attachments:

Overview

1. Building block approach: Annual revenue requirement, Regulatory asset base, Regulatory depreciation and Corporate income tax

2. Capital expenditure

3. Operating expenditure

6. Capital expenditure sharing scheme

9. Customer service incentive scheme

11. Classification of services

12. Control mechanisms

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14. Alternative control 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. Consumers are at the heart of our work, and we focus on ensuring a secure, reliable, and affordable energy future for Australia as we transition to net zero emissions.

A regulated 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 final decision for Jemena Electricity Networks [ABN 82 064 651 083] (Jemena), It is predicated on a series of constituent decisions summarised in section 5 of this Overview.[1]

This final decision will be implemented from 1 July 2026 and reflected in 2026–27 prices.

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

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

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).

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 that they comply with the NER and, in turn, further the NEO.

Our final decision allows Jemena to recover $2,000.3 million ($nominal, smoothed) in revenue from its customers in the upcoming 2026–31 period. This is $26.4 million (1.3%) less than Jemena's revised proposal, but $615.9 million (15.8%) more than our draft decision. It is $620.1 million (or 44.9%) higher than the revenue we approved for Jemena in the current, 2021–26 period.

Market factors, specifically rising inflation and interest rates, are driving higher revenues. In this final decision we estimate 35% of the increase in revenue from period to period can be attributed to these factors.

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1 NER, cl 6.12.1.

Our final decision also approves continued investment in Jemena's network to support its prudent and efficient delivery of the outcomes its consumers have identified as most important, including reliability, resilience and the energy market transition.

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

Networks have a vital role in delivering a system that serves consumers now and into the future.

In Victoria, the energy market is undergoing a complex transition. Emissions reduction targets, 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. Electrification, for example movement from gas to electric heating in the home and electrification of transport, is changing patterns in demand on the network. We continue to see high maximum electricity demand across the state. On 27 January 2026, the Australian Energy Market Operator (AEMO) reported an all-time operational demand record of 10,736 MW in Victoria.[2]

At the same time, prolonged outages following severe weather events and bushfires continue to increase focus on the reliability and resilience of the electricity networks. Regional reliability and differences in performance between, and even within, network areas are also front of mind for many communities.

Network costs are rising across the National Electricity Market (NEM), driven by a range of factors that affect reliability, security, and safety. The network is getting older, input costs are rising, and digitalisation is increasing the risk of cyber-attacks. The system is adapting to integrate Consumer Energy Resources (CER) and connect large, new loads such as data centres.

Proposals from Victorian DNSPs included significant uplifts in expenditure relative to the current period and to decisions we have made in recent years for other DNSPs. However, any new network infrastructure will be paid for by consumers. It is therefore important that businesses effectively utilise their existing infrastructure for distribution services, looking for non-network solutions and avoiding any unnecessary future infrastructure investment. New investment needs to clearly target where and how demand on the network is changing.

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 consumers and can support the energy transition currently underway. Where price signals are passed through by retailers, 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.

Broader cost of living pressures mean that many households are facing difficult choices about whether to heat, cool, or power their homes in the ways they want and need,

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2 AEMO, 'Victoria's electricity demand reached a new milestone', *LinkedIn*, 28 January 2026, accessed 1 March 2026.

emphasising the importance of balancing affordability with the urgency of the transition to protect consumers from avoidable long-term costs.

Our final decision focusses on the outcomes that are important to consumers

Where DNSPs have engaged with consumers to identify the outcomes that are most important to them, our role is to carefully assess whether the revenue, expenditure and tariff structures a DNSP has submitted are necessary to deliver those outcomes prudently and efficiently so that expenditure over the period under review will serve the long term interests of consumers.

When we undertake our assessment, we must consider whether we are satisfied that the expenditure proposed by the DNSP reasonably reflects prudent and efficient costs and a realistic expectation of future network demand and cost inputs. 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 the replacement capex (repex) model and economic benchmarking for opex.

We consider proposed tariff structures have been integrated into forecast demand and proposed spending as retailers respond to the price signals in cost reflective tariffs and consumers may change their behaviour.

We carefully balance incentives so that our decisions drive continued efficiency without compromising performance and service quality.

With the benefit of further and better supporting information requested in our draft decision, and provided in Jemena's revised proposal, we have accepted 94.1% of Jemena's revised opex forecast, and 86.6% of Jemena's revised capex forecast. Our final decision now approves increases of $266.8 million, or 29.9% ($2025–26) in capex and $118.1 million, or 24.4% ($2025–26) in opex relative to Jemena's expected actual expenditure in the current period.

The quality of supporting information and analysis that accompanied Jemena's initial proposal was not proportionate to the uplifts in expenditure proposed. We were not satisfied that the magnitude of increases in expenditure Jemena had proposed were in line with prudent and efficient decision making. Our draft decision underscored the need for further work by Jemena to ensure its expenditure proposals meet these objectives.

Jemena's revised capex proposal represented an increase in forecast capex compared to our draft decision. The revised proposal also included $32.9 million in new projects which were not included in its initial proposal, including additional replacements, ICT capex, fleet and innovation projects.

Our expectation is that DNSPs submit comprehensive and well-considered initial proposals at the start of the determination process. Initial proposals should not be considered drafts or works in progress.

The quality of proposals is even more critical when, as here, a revised proposal seeks to introduce material new expenditure that has not been subject to the same extensive period of assessment and consultation as initial proposals. Revised proposals are intended only as an opportunity for DNSPs to incorporate the substance of any changes required to address matters raised by our draft decision and our reasons for it. Any new or revised projects in

their revised proposals must be equally well-considered and justified with supporting information.

Consumer support alone does not guarantee any one or more of the assessment criteria have been met in respect of a DNSP's total capex or opex forecast, or of any individual projects or programs that have informed those forecasts. In developing proposals to address consumers' concerns, we expect DNSPs to identify, test (including through engagement), and choose from credible options and solutions that it can satisfy us will—when included in a total capex or opex forecast—reasonably reflect the expenditure criteria.

Where we are satisfied that a DNSP has achieved this, its forecasts of capex and opex for proposed options and solutions will form part of the total expenditure we approve.

Consumers are not well served by engagement that focuses on solutions that do not reflect those criteria, or by proposals that are not supported by rigorous and robust analysis, and which do not demonstrate that proffered options are prudent and efficient.

Where we are not satisfied, we must look to alternative options and solutions to approve total expenditure forecasts that will address consumers' concerns and deliver their preferred outcomes in a way that *is* prudent and efficient.

This is how we ensure that consumers are paying no more than necessary for safe, secure and reliable energy supply and a resilient network that meets their needs and delivers their preferred outcomes.

We make decisions on the total capex and total opex that DNSPs can recover from consumers for the 2026–31 period. While a proposal may be informed by a series of potential projects, we are not required to consider and individually approve the potential projects that have informed a DNSP's total capex or opex forecast. Ultimately, the DNSP will decide what projects it considers prudent and efficient to proceed with in the 2026–31 period.

Network augmentation and reliability

Augmentation expenditure (augex) is capital expenditure required to build or upgrade the network to address system constraints driven by changes in demand and network utilisation to enable the network service provider to comply with quality, safety, reliability, security of supply and greenhouse gas emission reduction target requirements. Jemena's augmentation consists of expenditure mainly on demand driven augex, connection enablement, reliability, compliance and safety.

The total forecast capex in our final decision includes $149.6 million in augex. This includes acceptance of its proposed capex for the East Preston Conversion Project, which will increase transfer capacity and flexibility for Jemena to manage its network during outage conditions, and for expansion and strengthening of its communications network to meet demand.

We have, however, included a smaller allowance for other demand driven augex than Jemena proposed. Our final decision does not include Jemena's proposed capex to establish a new Craigieburn zone substation and associated feeder works as well as a new Sunbury #15 feeder. Given the forecasts of demand and unserved energy in Jemena's revised proposal, we consider these works can be prudently deferred to the next period so that costs do not need to be recovered from consumers in 2026–31.

Our final decision also recognises the challenges in connecting new, large loads like data centres to the shared distribution networks. Our decision helps to ensure large customers like data centres are paying their own way when connecting to the distribution network. This includes paying for both the direct cost of connection that is only used by the data centre and a fair portion of the shared distribution network costs (the part of the network that consumers and data centres share).

We have carefully scrutinised demand forecasts, and targeted forecasting methodologies so that only net capex for data centre connections that are likely required in the forecast period are included in our decision. We have also removed cross-subsidisation of tax liability for these capital contributions by small customers. This helps ensure that the tax liability created by data centre and other large user contributions will not be unfairly subsidised by small customers.

Integration of consumer energy resources

CER include rooftop solar, energy storage devices, electric vehicles and other consumer appliances that can respond to demand or pricing signals. For distribution networks, CER integration expenditure is primarily for the purpose of accommodating the connection of additional rooftop solar to the network and maintaining the export service for rooftop solar customers.

Our final decision recognises that distribution networks play an important role in the facilitation and management of CER connected to their networks. Actions taken by distribution networks to support CER can benefit consumers, including through lower wholesale costs, lower network costs, and lower carbon emissions. We support Jemena's intentions to undertake beneficial CER expenditure.

We appreciate that this is a new and uncertain area where the quantification of costs and benefits is not straightforward. Our final decision includes $46.6 million for CER integration, informed by Jemena's proposed delivery of:

- dynamic voltage and power quality management to its network, which will allow Jemena . to maintain voltages within regulatory limits even with the proliferation of two-way power-flows from CER
- deployment of flexible service offerings to address increasing curtailment of exports (driven by CER)
- under-frequency load shedding upgrades which will improve Jemena's capability to maintain system security and meet compliance obligations
- improved data visibility and analytics, by creating a central data hub which can be used to enhance the efficiency of Jemena's other CER and augmentation projects.

Resilience

Resilience is the network's ability to continue to adequately provide network services and recover those services when subjected to disruptive events.[3] Submissions have emphasised the impact of prolonged outages following extreme weather events and the importance

[3] AER*, Network Resilience – A note on key issues,* April 2022, p 6.

consumers place on addressing this.[4] They have also highlighted the importance of ensuring any increase in investment is prudent and efficient.[5]

The total capex forecast in our final decision includes all $1.3 million ($2025–26) of Jemena's revised resilience proposal, which will fund network and community resilience programs to improve the resilience of its network.

Tariff structure statement

Network tariffs allow distributors to recover their approved revenue. Most customers pay network costs through network tariffs passed on to them through their electricity retailer.

Victorian distributors' tariff structure statements reflect an evolving tariff landscape and have responded to jurisdictional Government preferences, stakeholder consultation, and recent rule changes, such as the *Access, pricing and incentive arrangements for distributed energy resources rule change* (August 2021) that provided for two-way pricing. For example, the tariff structure statements include:

- new time-of-use tariffs for residential customers that include low network cost recovery during the middle of the day (solar soak tariffs) to incentivise and reward electricity use when there is generally abundant solar on the grid
- withdrawal of opt-in demand tariffs for small customers in recognition that retailers and small consumers generally find demand tariffs overly complex
- optional two-way tariffs for residential customers with CER that encourage export at times that benefit the grid
- innovative tariffs and tariff trials that send signals and rewards to large and flexible load/supply, including storage customers and kerbside electric vehicle charging.

The network tariff structures we have approved provide opportunities for consumers to benefit from using the network in ways that support efficient network outcomes and reduce network costs. They align with the Victorian Government's preference for cost reflective tariffs to remain optional. We also support Jemena's offer of tariffs to small customers that encourage them to opt-in to more cost-reflective options through their retailer.

DNSPs are incentivised to manage cost pressures without sacrificing performance

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. By only allowing efficient costs in our approved revenues, we promote achievement of the NEO and revenue and pricing principles and ensure consumers pay no more than necessary for the safe and reliable delivery of electricity.

We strengthen and balance those incentives by putting targeted incentive schemes in place at the start of each period. Our final decision is that in 2026–31 an opex Efficiency Benefit Sharing Scheme (EBSS) and Capital Expenditure Sharing Scheme (CESS) will apply to encourage businesses to pursue expenditure efficiencies. At the same time, a Service Target

4 Hon Lily D'Ambrosio MP, *Submission - Victorian electricity distribution proposals 2026–31*, January 2026.

5 Hon Lily D'Ambrosio MP, *Submission - Victorian electricity distribution proposals 2026–31*, January 2026.

Performance Incentive Scheme (STPIS) will provide financial incentives to maintain and improve reliability and customer service performance, so that costs are not reduced at the expense of service quality.

Feedback on our draft decisions highlighted strong support for Jemena's proposed Customer Service Incentive Scheme (CSIS), and the value of the CSIS in providing consumers with agency in identifying services that are most important to them. However, since its inception in our last determinations for Victorian DNSPs, the CSIS has been subject to significant compliance issues, including multiple suspensions and transitional arrangements since scheme implementation, as well as an observable decrease in the quality of proposals. As a result, the CSIS has attracted criticism from consumer representatives, DNSPs, and customers voicing concerns regarding redundancy, duplication of STPIS functions, and suggestions that the scheme might be replaced by non-incentivised reporting.

To deliver the intended benefits of a CSIS, its design must be robust, its intentions clear and its performance parameters measurable. We were not satisfied that Jemena's initial proposal was fit for purpose.

Jemena's revised proposal has not addressed the concerns our draft decision raised with its proposed CSIS. Our final decision will therefore not apply a CSIS in 2026–31. While not a long-term solution, our final decision delivers some incentivised customer service benefits in the absence of a CSIS by applying the customer service (telephone answering) component of the STPIS. Looking forward, the AEMC's Electricity Network Regulation Review is one opportunity for consideration of the role of incentive schemes in our distribution determinations and how the challenges encountered with the CSIS can be addressed.

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1 Our final decision

Our final decision allows Jemena to recover a total revenue of $2,000.3 million ($nominal, smoothed) from its consumers from 1 July 2026 to 30 June 2031.

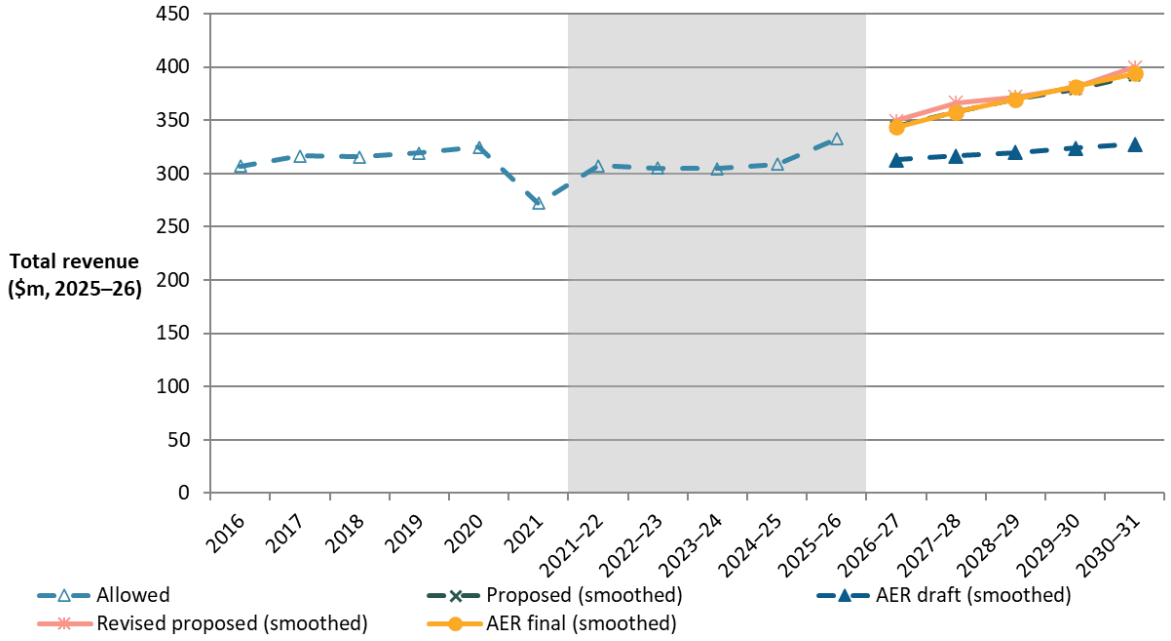
Our final decision revenue is $620.1 million (44.9%) more than Jemena's allowed revenue in the 2021–26 period in nominal terms. In the sections below we briefly outline what is driving Jemena's revenue.

1.1 What is driving revenue

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

In real terms, this final decision would allow Jemena to recover $1,846.5 million ($2025–26, smoothed) over the 2026–31 period. This is $287.9 million (18.5%) higher than the revenue we approved for Jemena in the current, 2021–26 period. Jemena's revenue over time is shown in Figure 1.

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



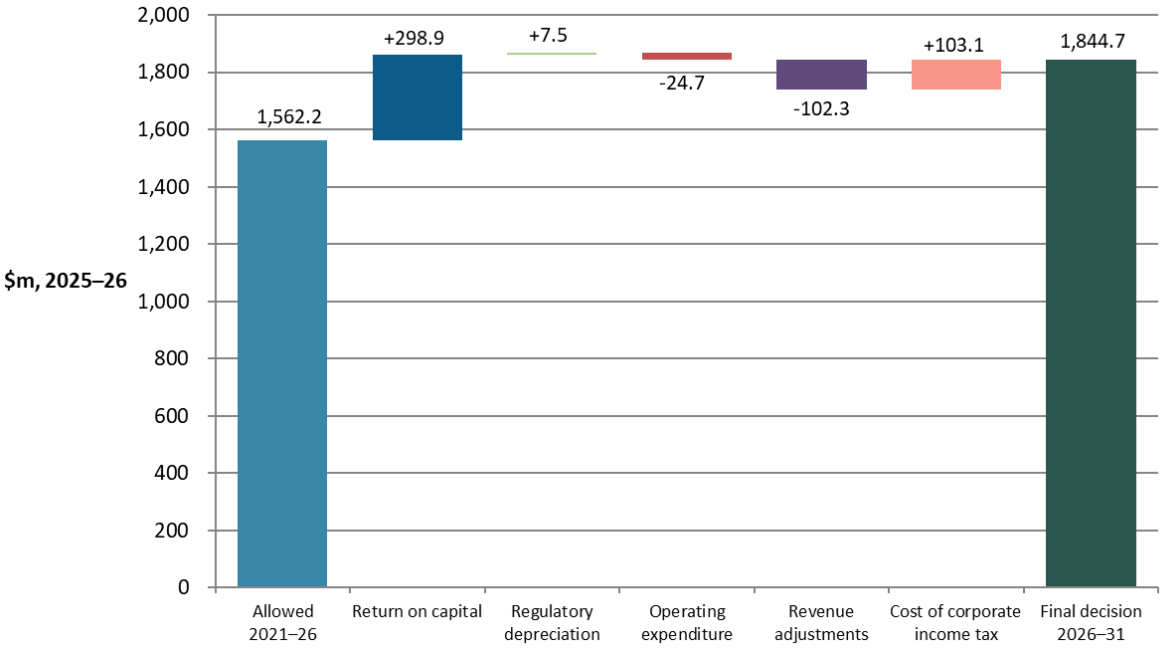
Source: AER analysis.
Note: For presentational purposes, the revenue for the half-year 2021 extension period has been doubled.

Figure 2 highlights the key drivers of the change between the revenue approved for Jemena for the 2021–26 period and in this final decision for the 2026–31 period. It shows that our final decision provides for:

- A return on capital which is $298.9 million (63.5%) higher than the 2021–26 period, driven by:

  - a higher rate of return being applied in the 2026–31 period, reflecting changes in financial market data, observed in accordance with the 2022 *Rate of Return Instrument*
  - actual regulatory asset base (RAB) growth in the current 2021–26 period due in part to higher actual inflation
  - higher forecast net capex in the 2026–31 period compared to the 2021–26 period, which is contributing to growth in Jemena's forecast RAB over the 2026–31 period.
- A return of capital (regulatory depreciation), which is $7.5 million (2.2%) higher than the 2021–26 period. This is due to an increase to straight-line depreciation driven by higher forecast capex in the 2026–31 period and higher opening RAB as at 1 July 2026.
- Forecast opex which, while higher than Jemena's actual opex in the 2021–26 period, is $24.7 million (3.9%) lower than the forecast we approved in the 2021–26 period.
- Revenue adjustments under AER expenditure incentive schemes, which are $102.3 million (121.9%) lower than the 2021–26 period, mainly due to CESS penalties in the 2026–31 period, and a reduction in EBSS benefits in 2026–31 period.
- A forecast cost of corporate income tax, which is $103.1 million (271.3%) higher than the 2021–26 period. This is due to a projected increase in capital contributions, and to a higher return on equity and regulatory depreciation than in the current period.

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



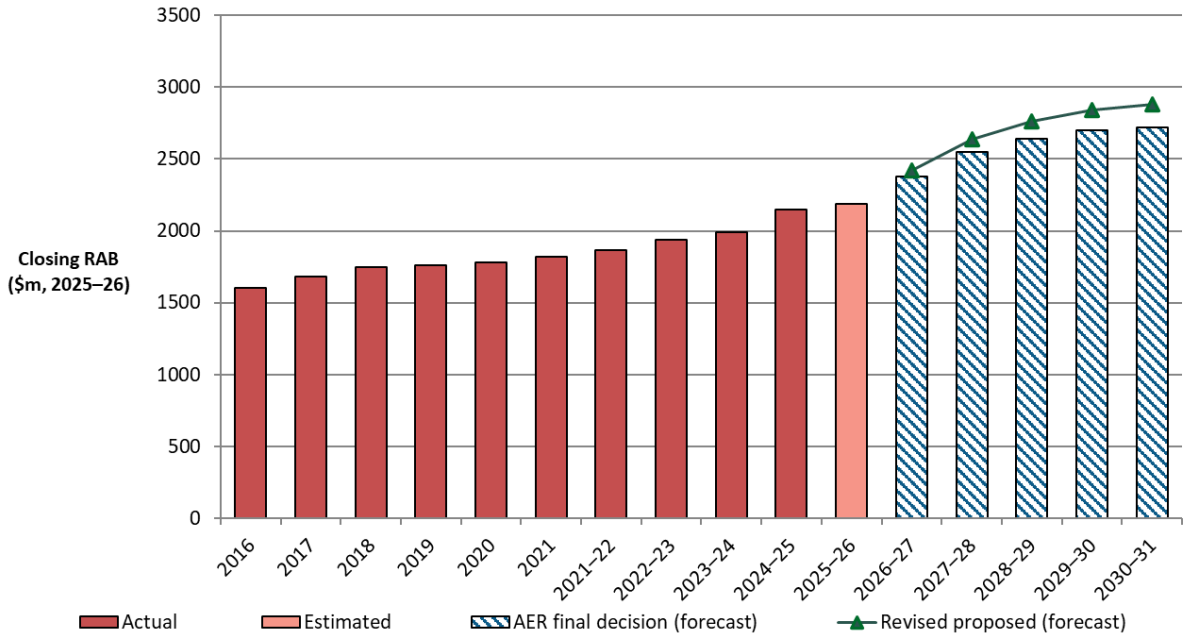
Source: AER analysis.
Note: This comparison is based on converting nominal forecast amounts to real dollar terms using lagged consumer price index (CPI). The 2021–26 building blocks and allowed revenue also excludes cost pass through amounts recovered through a C-factor mechanism as part of the annual pricing process.

Figure 3 shows the value of Jemena's RAB over time in real terms. After a RAB increase of 22.9% over the 2021–26 period, our final decision forecasts a RAB increase of $531.2 million (24.3%) 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, this increase is lower than what Jemena proposed, reflecting our final decision to reduce Jemena's revised proposed forecast capex.

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

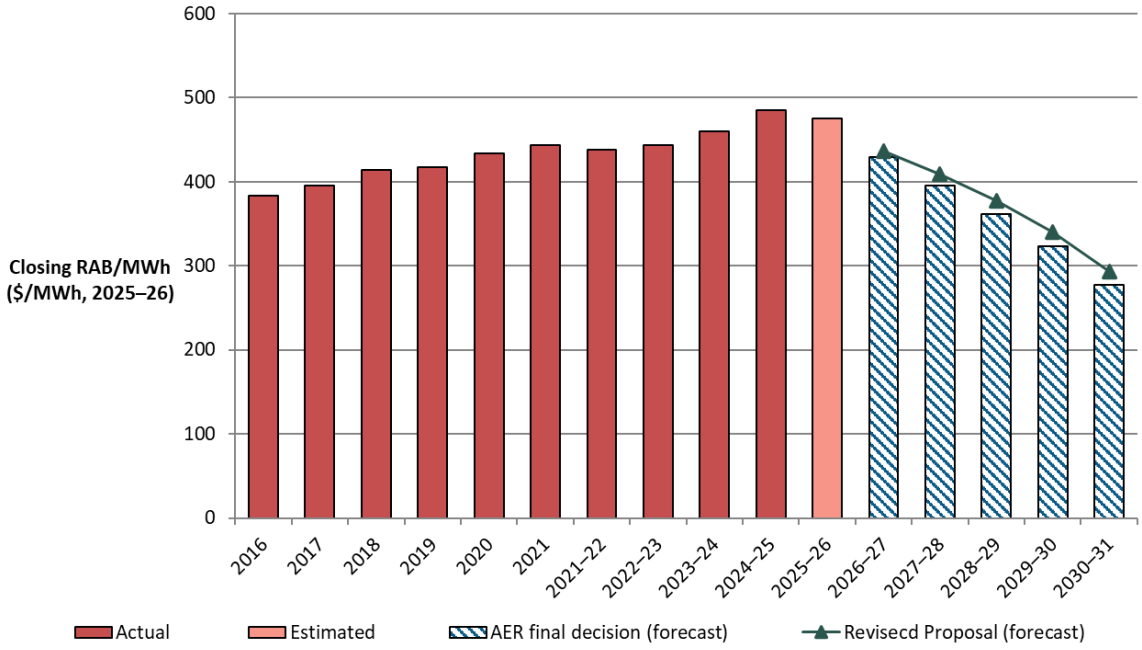
Figure 3 Jemena's RAB value over time ($ million, 2025–26)



Source: AER analysis.

We consider efficient investment in, and efficient operation and use of, electricity services are important to minimise the required capex and the RAB. In real terms, Jemena's RAB per unit of energy consumption (MWh) has increased steadily over the past 2 periods. As can be seen in Figure 4, this measure is expected to decline in 2025–26 based on consumption growth which will offset a small increase in the RAB in real terms. Over the 2026–31 period, Jemena's RAB per MWh continues to show a forecast decline driven by an increased rate of forecast energy consumption, which more than offsets the projected growth to the RAB. This is based on Jemena's forecast energy delivered and could change depending on the actual volume of energy delivered.

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



Source: AER analysis.

1.2 Expected impact of our final decision on electricity bills

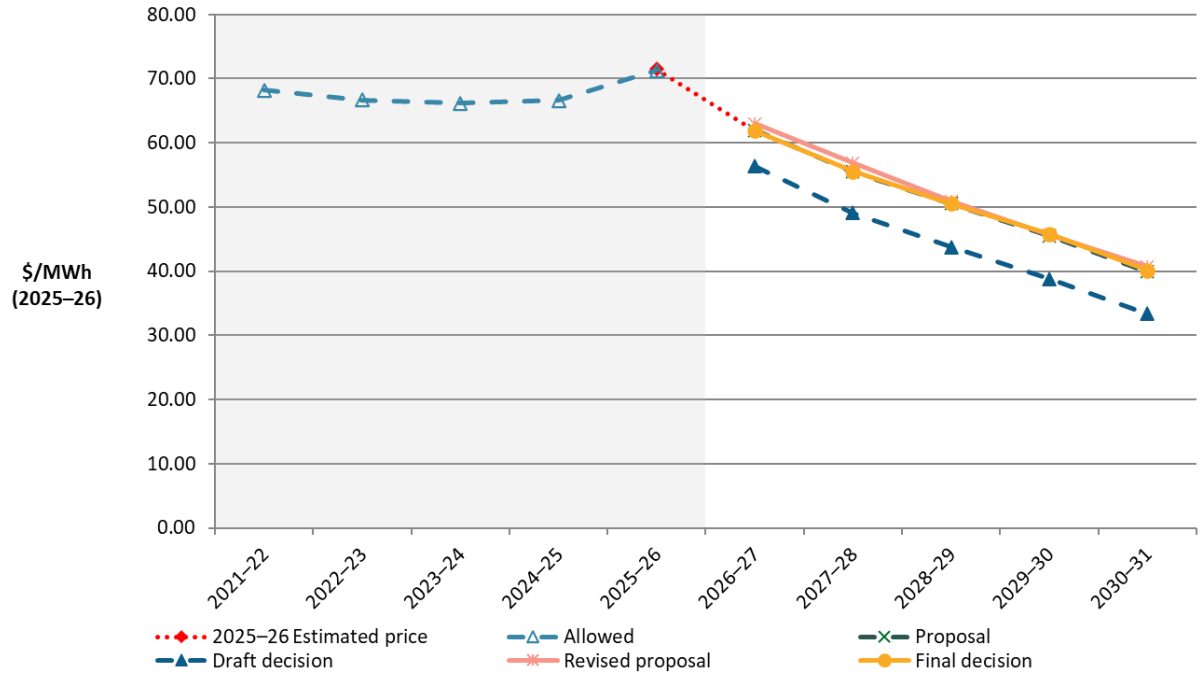
Our decision on Jemena's revised proposal sets the revenue allowance that forms the major component of its network charges for the next 5 years.

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 impact of this final decision would be a total reduction to Jemena's distribution charges of around 43.9% in real terms by 2030–31 compared to current, 2025–26 levels, or an average reduction of 10.9% per annum.[6] This estimate will be subject to ongoing revenue adjustments and changes in consumer energy consumption during the 2026–31 period. Figure 5 compares this indicative price path for the 2026–31 period to the 2021–26 period.

6 The average decrease to indicative network charges of 10.9% ($2025–26) per annum reflects 2 components: 1) The final decision smoothed revenue average increase of 3.6% per annum ($2025–26); and 2) Jemena's revised proposed forecast energy delivered in its distribution network area, which is expected to increase on average by 16.3% per annum.

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



Source: AER analysis.

1.2.1 Potential bill impact

Jemena's distribution charges make up around 29% of its residential consumers' electricity bills and 37% of its small business customers' electricity bills.[7] Our final 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 also contribute to the prices ultimately paid by consumers. These are the cost of purchasing energy from the wholesale market, core transmission network charges, environmental scheme costs and the costs and margins applied by electricity retailers.[8] These components of the bill sit outside the decision we are making here and will also continue to change throughout the period.

In nominal terms, which include the effect of expected inflation, the impact of this final decision would be a reduction to the distribution component of consumers' electricity bills. For illustrative purposes only, we estimate the impact of our final decision on the average annual electricity bill for a typical customer in Jemena's network area, as it is today ($nominal), would be:[9]

- A reduction of $189 (11.5%) by 2030–31, or an average reduction of $38 per annum for a residential customer. This reflects:
  - a $174 reduction for distribution standard control services charges

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

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

9 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.

  - a $14 reduction for metering.
- A reduction of $516 (13.9%) by 2030–31, or an average reduction of $103 per annum for a small business customer. This reflects:
  - a $498 reduction for distribution standard control services charges
  - an $18 reduction for metering.

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 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 to increase from 4,613 GWh in 2025–26 to 9,819 GWh in 2030–31, an increase of 5,206 GWh, or 112.9% over the period. This is the forecast that has informed the illustrative estimates of tariff and bill impacts in this final decision. A variance in energy consumption compared to that forecast by Jemena would lead to bill impacts that are higher or lower than what we have estimated.

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.

For example, if energy delivered were to increase over the period at only 40% of the rate forecast by Jemena, the modelled impact on average annual bills would be: [10]

- a smaller nominal reduction of $45 (2.7%) by 2030–31 for a residential consumer[11]
- a smaller nominal reduction of $105 (2.8%) by 2030–31 for a small business consumer.[12]

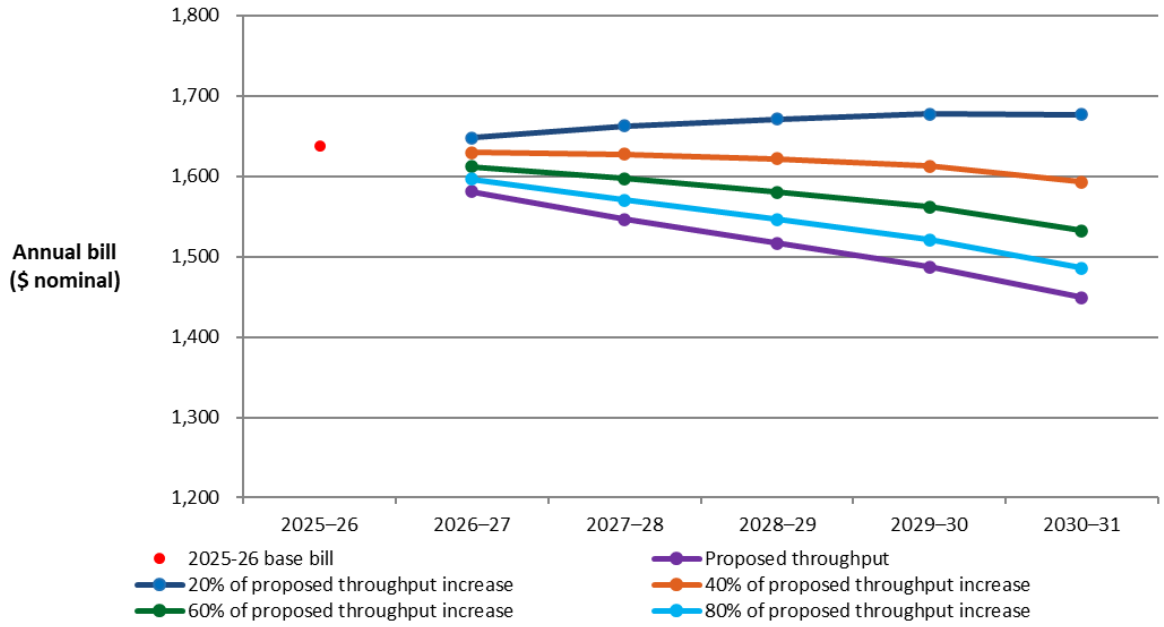
Figure 6 shows the average annual bill for a residential consumer for a range of alternative energy delivered forecasts.

[10] This would therefore reflect energy throughput of 2,082 GWh in 2030–31, or an increase in energy throughput over the period of 45.1% compared to the 112.9% increase proposed by Jemena.

[11] This reflects a reduction of $30 for distribution SCS, and a reduction of $14 for metering.

[12] This reflects a reduction of $87 for distribution SCS, and a reduction of $18 for metering.

Figure 6 Sensitivity of energy delivered on annual residential bills



Source: AER analysis.

1.3 Consumer engagement

Consumer engagement during the regulatory process is an important way to provide us with supporting evidence that proposals have been aligned with consumer interests and expectations.

We 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.

Feedback on our draft decision sought clarity as to the impact that engagement has had on our decision making, and our draft decisions to reduce proposed expenditure in areas that were of key interest to consumers.

Where consumers have been engaged on the outcomes a DNSP should seek to achieve, our role is to carefully assess the prudency and efficiency of the expenditure the DNSP has submitted is necessary to deliver them.

The framework under which we must assess forecast expenditure is set out in the NER.

A DNSP must, in its proposal to the AER, include the total forecast opex and capex it considers is required to achieve the opex and capex objectives.[13] These objectives include meeting or managing expected demand for services over the relevant period. They also include complying with all applicable regulatory obligations or requirements, including any

[13] NER, cls 6.5.6(a), 6.5.7(a).

service standards applicable to quality, reliability and security of supply. To the extent that there is no applicable regulatory obligation or requirement in relation to the quality, reliability or security of supply the objectives require that quality, reliability or security of supply are maintained over time.

We must accept the DNSP's proposed forecast if we are satisfied that, in total, it reasonably reflects each of the opex and capex criteria:[14]

1. the efficient costs of achieving the opex and capex objectives; and
2. the costs that a prudent operator would require to achieve opex and capex objectives; and
3. a realistic expectation of the demand forecast, cost inputs and other relevant inputs required to achieve the opex and capex objectives.

These criteria reflect and serve to support the NEO, to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity with respect to price, quality, safety, reliability and security of supply of electricity, and the reliability, safety and security of the national electricity system.[15]

All 3 criteria must be satisfied before we accept a proposal.

If we are not satisfied that the proposed forecast reasonably reflects costs that are efficient, and prudent, and a realistic expectation of forecast demand, cost and other inputs required to achieve the opex and capex objectives, we must not approve it.[16]

Consumer engagement and support is valuable both to DNSPs in the development of their proposals, and to us in assessing them and making decisions that are in consumers' long-term interests. The extent to which a proposed forecast of capex or opex "includes expenditure to address the concerns of consumers as identified by the DNSP in the course of its engagement with distribution service end users or groups representing them" is one of 12 non-exhaustive factors to which the AER must have regard in making the required assessment against the opex and capex criteria.[17]

Requirements for prudency and efficiency are not at odds with the intention that proposals include expenditure to address consumers' concerns. However, consumer support alone does not guarantee any one or more of the assessment criteria have been met in respect of a DNSP's total capex or opex forecast, or of any individual projects or programs that have informed those forecasts.

When considering the outcomes of a DNSP's consumer engagement, and consumers' responses to our decisions, we have regard to the consumer concerns the DNSP seeks to address (as put in our Better Resets Handbook, the outcomes consumers are seeking).

In developing proposals to address those concerns, and achieve those outcomes, we expect a DNSP to identify, test (including through engagement), and choose from credible options

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14 NER, cls 6.5.6(c), 6.5.7(c)(1).

15 NEL, s 7.

16 NER, cls 6.5.6(d), 6.5.7(d).

17 NER, cls 6.5.6(e)(8), 6.5.7(e)(3).

and solutions it considers will achieve the opex and capex objectives, and that it can satisfy us will reasonably reflect the opex and capex criteria.

Where we are satisfied that a DNSP has achieved this, its proposed options and solutions will form part of the total opex and capex we approve.

Where we are not satisfied, we must look to alternative forecasts of capex or opex to approve total expenditure forecasts that will address consumers' concerns and deliver their preferred outcomes in a way that does achieve the opex and capex objectives and satisfy the opex and capex criteria.

That may mean our total opex and capex forecasts assume the same (or similar) options or solutions that a DNSP has engaged on and subsequently proposed but at a more efficient cost, or at a volume that better reflects a realistic expectation of demand forecasts.

It may mean that our total forecast defers, or does not include for the period under assessment, expenditure on an option or solution we are not satisfied is needed at the time the DNSP has proposed, and which could instead occur later so that it is not necessary or appropriate to recover the costs from consumers yet.

It may mean that we do not include the option or solution the DNSP has proposed, in which case our total expenditure forecasts will be informed by alternative options we consider would address consumer concerns, and ultimately support the same outcomes in way that we are satisfied is prudent, and reflects a realistic expectation of demand forecasts and cost and other inputs.

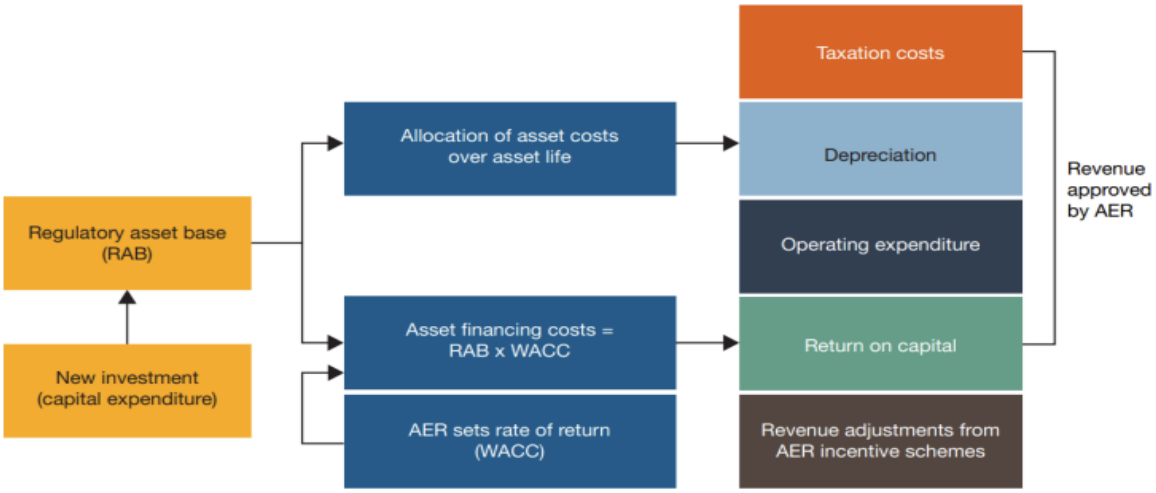
This is how we ensure that consumers are paying no more than necessary for safe, secure and reliable energy supply and a resilient network that meets their needs and delivers their preferred outcomes.

2 Key components of our final decision on revenue

Jemena's proposed revenue reflects its forecast of the efficient cost of providing distribution network services over the 2026–31 period. Its revenue proposal, and our assessment of it under the NEL and NER, are based on 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 Efficiency Benefit Sharing Scheme (EBSS) and Capital Expenditure Sharing Scheme (CESS)
- estimated cost of corporate income tax.

Figure 7 The building block model to forecast network revenue



Source: AER.

Revenue smoothing

Our final decision incudes a determination of Jemena's annual revenue requirement (unsmoothed revenue) and annual expected revenue (smoothed revenue) across the 2026–31 period. The smoothed revenues we set in this final decision are the amounts that Jemena

will target for its annual pricing purposes and recover from its customers for the provision of standard control services for each year of the 2026–31 period.[18]

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

For this final decision, we approved lower revenues than Jemena's revised proposal. This is mainly driven by our reductions to Jemena's forecast capex and opex. However, our final decision allows for higher revenues than those determined in the 2021–26 period.

However, our final decision allows for higher revenues than those determined in the 2021–26 period. In nominal terms, Jemena's unsmoothed revenue for the first year of the 2026–31 period (2026–27) is about 8.9% higher than its approved revenue for the last year of the 2021–26 period (2025–26). It then increases by an average of 5.0% per annum over the remaining 4 years of the period.

We are mindful of the impact these increases in revenue could have on network charges for Jemena's customers (in the event forecast energy growth is lower than expected). Consequently, we have smoothed the increase in expected revenues over the 2026–31 period for Jemena.

Our final decision results in nominal increases of 6.9% per annum to the smoothed revenues in the first 2 years of the 2026–31 period (2026–27 and 2027–28), followed by smaller increases of 6.0% per annum in the remaining 3 years of the 2026–31 period (2028–29 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.

We consider our final decision smoothing path is reasonable as our smoothed revenue profile reduces the large initial increase in year 1 and effectively smooths this over the remaining 4 years of the period.

2.1 Regulatory asset base

The RAB accounts for the value of regulated assets over time. To set the 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

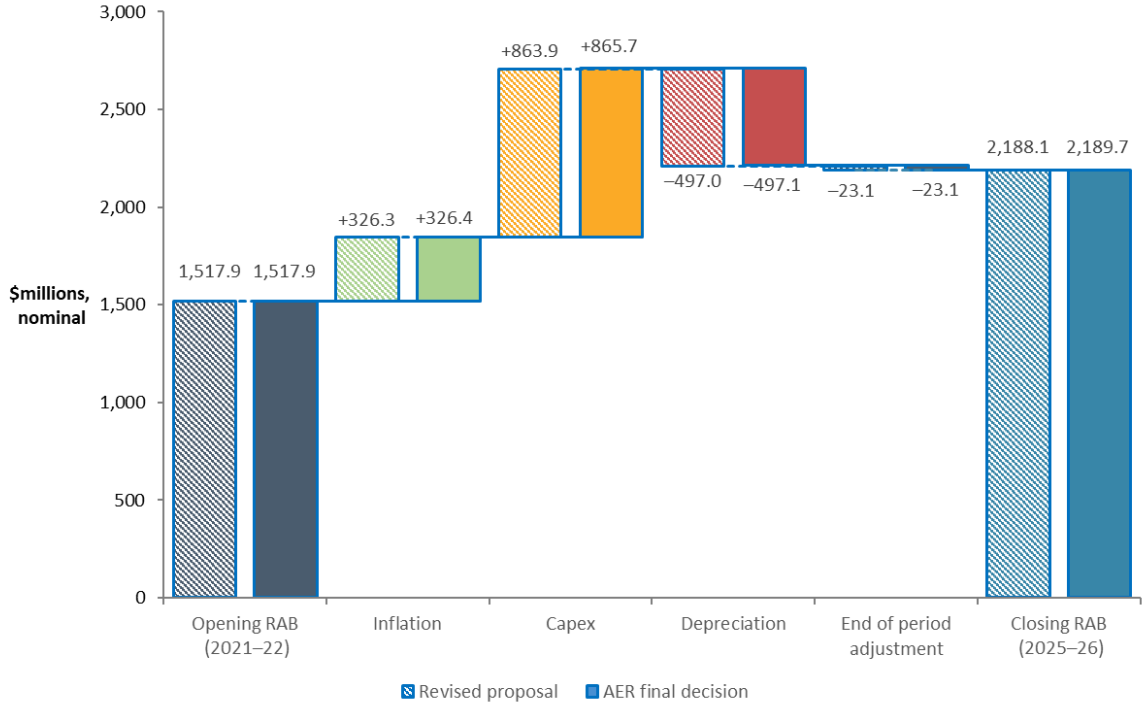
[18] Our final decision expected revenues have not factored in any changes arising from incentive scheme amounts, cost pass throughs or unders/overs reconciliation that usually occur in the annual pricing process to come up with the total allowed revenue.

things being equal, a higher RAB would increase both the return on capital and regulatory depreciation components of the revenue determination.

For this final decision, we have determined an opening RAB value of $2,189.7 million ($ nominal) as at 1 July 2026. This value is $1.7 million (0.1%) higher than Jemena's revised proposed opening RAB value of $2,188.1 million. This reduction is largely due to our update to the roll forward model for capital contributions to reflect revisions provided by Jemena after submission of its revised proposal.

Figure 8 shows the key drivers of change in Jemena's RAB over the 2021–26 period compared to its revised proposal.

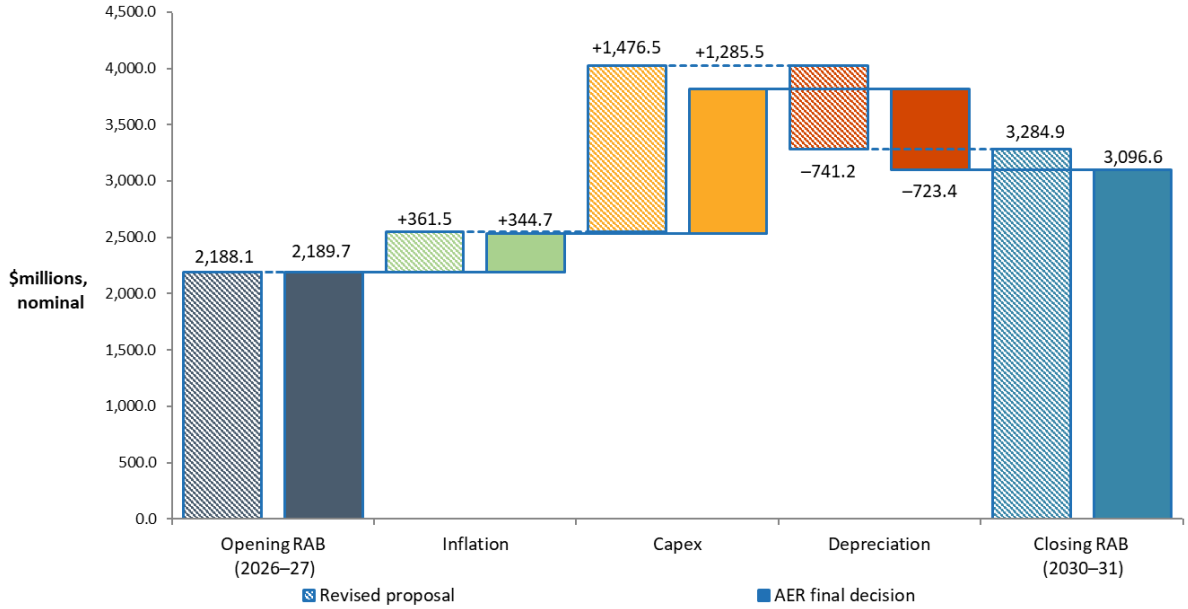
Figure 8 Key drivers of change in the RAB over the 2021–26 period – revised proposal compared with AER's final decision ($million, nominal)



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

Figure 9, likewise shows the key drivers ($nominal) of the change in Jemena's forecast RAB over the 2026–31 period compared to its revised proposal. Our final decision projects an increase of $906.8 million (41.4%) to the RAB by the end of the 2026–31 period compared to the $1,096.8 million (50.1%) increase in Jemena's revised proposal. We have determined a projected closing RAB of $3,096.6 million ($ nominal) as at 30 June 2031, which is $188.4 million (5.7%) lower than Jemena's revised proposal of $3,284.9 million. This lower value is mainly due to our final decision to reduce Jemena's forecast capex (section 2.4). It also reflects our final decisions on the opening RAB as at 1 July 2026, expected inflation (section 2.2) and forecast depreciation (section 2.3). The reasons for our final decision are discussed in Attachment 1.

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



Source: AER analysis.
Note: Capex is net of forecast disposals and capital contributions. It is inclusive of the half-year WACC to account for the timing assumptions in the 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.[19]

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

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

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

We are required by the NEL to apply the RORI to estimate an allowed rate of return.[20] For this final decision, we have applied the 2022 RORI.[21]

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

20 NEL, section 18H.

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

Jemena's revised proposal adopted the 2022 RORI.[22] Our final decision rate of return of 6.17% (nominal vanilla) is higher than the 6.02% placeholder in the revised proposal, principally due to an increase in the risk-free rate.

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 final decision accepts Jemena's proposed risk-free rate[23] and debt averaging periods[24] because they are consistent with the 2022 RORI.[25]

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

	AER's draft decision (2026–31)	Jemena's revised proposal (2026–31)	AER's final decision (2026–31)	Allowed return over the regulatory control period
Nominal risk-free rate	4.25%	4.25%	4.62%[a]	Constant (%)
Market risk premium	6.20%	6.20%	6.20%	Constant (%)
Equity beta	0.6	0.6	0.6	Constant
Return on equity (nominal post-tax)	7.97%	7.97%	8.34%	Constant (%)
Return on debt (nominal pre-tax)	4.72%	4.72%	4.73%[b]	Updated annually
Gearing	60%	60%	60%	Constant (60%)
Nominal vanilla WACC	6.02%	6.02%	6.17%[c]	Updated annually for return on debt
Expected inflation	2.55%	2.66%	2.62%	Constant (%)

Source: AER analysis; AER, *Overview - Draft decision - Jemena distribution determination 2026–31*, September 2025, p 14; Jemena, *JEN 2026–31 Revised Proposal*, December 2025, p 51; Jemena, *JEN - RP - Att 08-05M SCS PTRM,* December 2025.

(a) Calculated using Jemena's risk-free rate averaging period of 40 business days ending 30 December 2025.

(b) Calculated using Jemena's actual nominated return on debt averaging period.

(c) Applied to the first year of the 2026–31 regulatory control period.

22 Jemena, *JEN 2026–31 Revised Proposal*, December 2025, p 51.

23 Jemena, *JEN - Att 08-02 Averaging periods - 20250131 – Confidential*, 31 January 2025, p 1.

24 Jemena, *JEN - Att 08-02 Averaging periods - 20250131 – Confidential*, 31 January 2025, p 1.

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

Debt and equity raising costs

In addition to providing 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 operating expenditure (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 capital expenditure (capex) forecast because these costs are only incurred once and would be associated with funding particular capital investments. Our approach to forecasting debt and equity raising costs is set out in more detail in previous AER revenue determinations (for example, see our 2025–30 Directlink Electricity Transmission Determination final decision).[26] Jemena has proposed to use our approach to estimate debt and equity raising costs.[27]

Our final decision is to apply a debt raising cost of 8.70 basis points per annum, which has been used to calculate the debt raising costs included in total forecast opex.

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 $18.7 million.

Imputation credits

Our final decision applies a value of imputation credits (gamma) of 0.57 as set out in the 2022 RORI. Jemena's revised proposal also adopted this value.[28]

Expected inflation

As set out in Table 2, our estimate of expected inflation is 2.62%. It is an estimate of the average annual rate of inflation expected over a five-year period based on the outcome of our 2020 inflation review. Jemena's revised proposal also adopted our approach.[29]

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

	Year 1	Year 2	Year 3	Year 4	Year 5	Geometric average
Expected inflation	2.90%	2.60%	2.57%	2.53%	2.50%	2.62%

Source: AER Analysis; RBA, *Statement on Monetary Policy*, February 2026, Table 3.1: Detailed Forecast Table. See the *Statement on Monetary Policy*.

Our final decision uses the Reserve Bank of Australia's (RBA) February 2026 Statement on Monetary Policy which contains a consumer price index (CPI) forecast for the financial years ending 30 June 2027 and 30 June 2028. This means the first 2 years of the 2026–31 period are based on RBA forecasts and, thereafter, a linear glide path from year 3 to the mid-point of the RBA's inflation target band of 2.5% in year 5.

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26 AER, *Final decision - Attachment 3 - Rate of Return - Directlink Electricity Transmission Determination 2025 to 2030*, September 2024, pp 4–6.

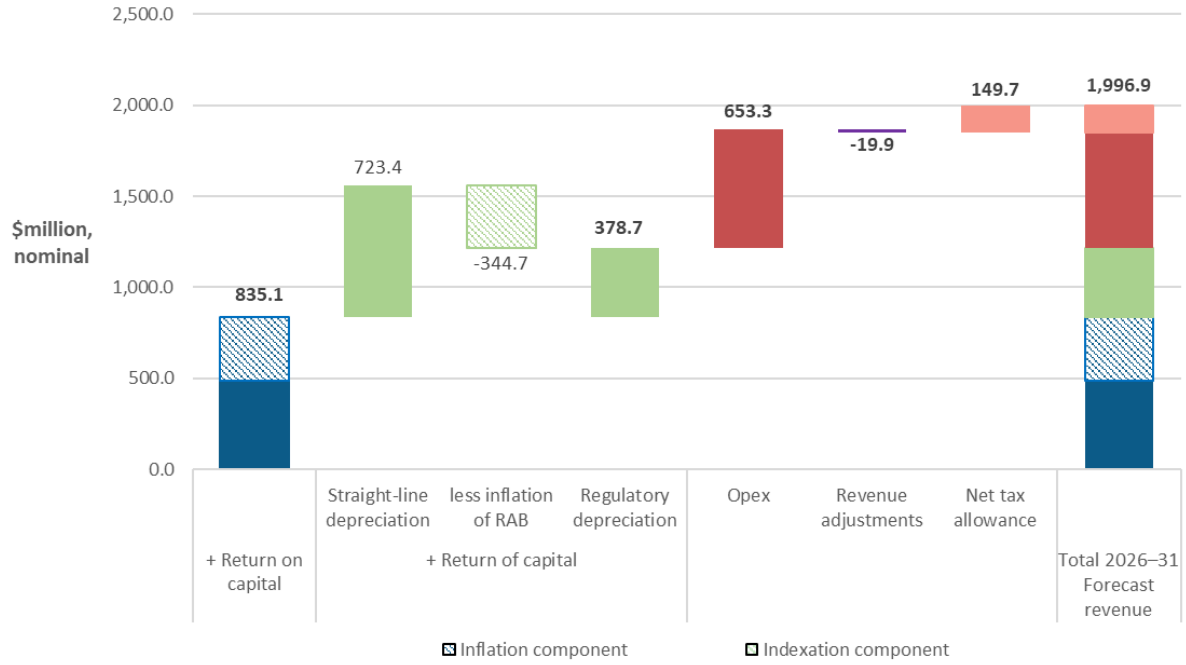
27 Jemena, *JEN - RP - Att 08-05M SCS PTRM,* December 2025.

28 Jemena, *JEN 2026–31 Revised Proposal*, December 2025, p 51.

29 Jemena, *JEN 2026–31 Revised Proposal*, December 2025, p 50.

Figure 10 isolates the impact of expected inflation from other parts of our final decision to illustrate its effect on the return on capital and regulatory depreciation building blocks, and the total revenue allowance. Where all other elements are held constant, lower expected inflation reduces the return on capital but increases regulatory depreciation.

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



Source: AER analysis.

2.3 Regulatory depreciation (return of capital)

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

Our final decision determines a regulatory depreciation amount of $378.7 million ($ nominal) for the 2026–31 period. This is a reduction of $1.0 million (0.3%) from Jemena's revised proposal of $379.6 million.

This reduction is primarily due to our final decision to reduce Jemena's forecast capex, which has reduced straight-line depreciation in the 2026–31 period. Our final decision to apply an expected inflation rate for the 2026–31 period that is lower than that in Jemena's revised proposal has partially offset the reduction in the regulatory depreciation building block.

2.4 Capital expenditure

Our final decision is to not accept the total forecast capex of $1,338.5 million ($2025–26) in Jemena's revised proposal. Our alternative forecast is $1,159.1 million, which is 13.4% below Jemena's forecast.

Our decision is based on a balanced consideration of various factors, including the revised capex proposal from Jemena, stakeholder submissions, investment need and service reliability performance. We consider our alternative forecast will sufficiently allow a prudent and efficient service provider in Jemena's circumstances to meet the capex objectives.

Table 3 compares our alternative estimate of forecast capex to Jemena's revised proposal.

Table 3 AER's final decision on Jemena's total net capex forecast ($ million, 2025–26)

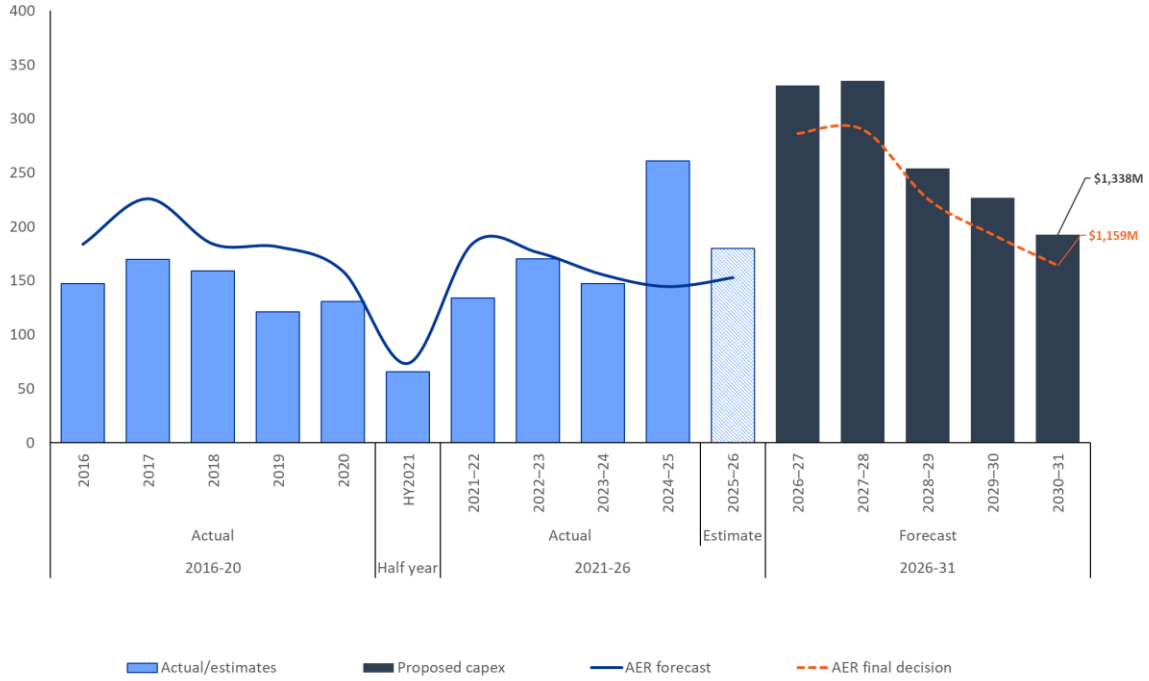
	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Jemena's revised proposal	330.6	334.8	253.9	226.8	192.3	1,338.5
AER's final decision	286.5	290.2	225.7	192.6	164.1	1,159.1
Difference ($)	**-44.1**	**-44.7**	**-28.2**	**-34.2**	**-28.3**	**-179.4**
Difference (%)	**-13.3%**	**-13.3%**	**-11.1%**	**-15.1%**	**-14.7%**	**-13.4%**

Source: Jemena's revised proposal, AER analysis.
Note: Jemena's revised proposal capex model included $18.5 million for a resilience project but Jemena's revised proposal noted that this was included in error, this amount is not included in the revised proposal figures above.
Jemena's revised proposal reflected a revised methodology for forecasting data centre connections capex, including only connections that are in flight or under a firm offer. After it submitted its revised proposal Jemena updated its forecast for data centre connections capex in line with this methodology - this updated forecast is reflected in the revised proposal figures above.
Jemena's revised proposal capex model included an error in calculating inflation adjustments to capitalised overheads. The revised proposal figures above reflect correction of this error and adjustment to reflect the impact of updated data centre connections and resilience capex on forecast overheads.

Figure 11 places our final decision capex forecast of $1,159.1 million in the context of historical capex. Our final decision capex forecast is:

- $344.5 million, or 42.3% higher than the capex forecast we approved in our final decision for the 2021–26 regulatory control period
- $266.8 million, or 29.9% higher than Jemena's actual (and estimated) capex for the 2021–26 regulatory control period.

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



Source: Jemena revised proposal and AER analysis
Note: Capex is net of capital contributions and disposals. Revised proposal figures reflect updates and corrections noted at Table 4.

Jemena's revised proposal forecast $1,338.5 million ($2025–26) of capex over the 2026–31 regulatory control period. This represented an increase of 50.0% compared to its actual and expected expenditure over the 2021–26 period.

Jemena's revised capex proposal represented an increase in forecast capex compared to our draft decision, driven by factors such as replacements, augmentations, and overheads. The revised proposal also included a large proportion of connections capex, representing 53% of its total forecast capex. The revised proposal also included $32.9 million in new projects which were not in its initial proposal, including additional replacements, ICT capex, fleet and innovation projects

In our draft decision, we asked Jemena to address the information gaps and/ lack of supporting information in its initial capex proposal. We asked Jemena to address data quality concerns and provide robust business cases in support of its proposed repex, including improved information on the risk and consequent cost of failure for high value, low volume asset replacements. We also asked Jemena to provide improved demand forecasts that would allow proper analysis of demand-driven augex, and improved cost-benefit analysis for other non-demand driven augmentation (including CER programs).

In responding to our draft decision, Jemena:

- Accepted our draft decision on property, other non-network capex, pole replacements, and some innovation programs, as well as some programs in Information and Communications Technology (ICT), CER integration, and resilience where we accepted Jemena's initial proposal forecast/

- Proposed connections capex in line with our draft decision methodology by including only forecasts data centre connections that are in-flight or under a firm offer and accepted our draft decision on other connections capex.

For this final decision, our assessment focused on the following unresolved issues:

- replacement capex
- augmentation capex
- capitalised overheads
- fleet
- CER programs for voltage and power quality management, and flexible services
- some ICT and innovation programs.

In this final decision we have not included capex for Jemena's proposed ICT project for end user computing. We consider that our forecast for recurrent ICT already incorporates an allowance for this expenditure.

We have also made reductions to Jemena's forecast in other categories because we were not provided with sufficient evidence that its forecast was prudent and efficient:

- Replacement capex for pole top structures, service lines, and zone substation locks and security systems.
- Demand driven augmentation.
- Capitalised overheads.
- Fleet.
- Recurrent ICT capex.
- CER integration capex for flexible services.
- Innovation expenditure.
- Escalation applied to contract labour.

Table 4 sets out our final decision for Jemena by capex category. Further detail and reasons for our final decision on forecast capex are set out in Attachment 2.

Table 4 AER's final decision by capex category ($million, 2025–26)

Category	Jemena's revised proposal	AER's final decision	Difference ($/%)	
Replacement	419.3	370.2	-49.1	-11.7%
Augmentation	203.9	149.6	-54.4	-26.7%
Connections	1,221.9	1,221.9	-	-
ICT	115.0	109.7	-5.2	-4.6%
Property	17.4	17.4	-	-

Category	Jemena's revised proposal	AER's final decision	Difference ($/%)	
Fleet	47.9	33.6	-14.3	-29.9%
CER integration	49.4	46.6	-2.8	-5.7%
Non-network - other	2.7	2.7	-	-
Capitalised overheads	240.9	204.3	-36.7	-15.2%
Gross total	**2,318.4**	**2,155.9**	**-162.5**	**-7.0%**
Less customer contributions	977.1	967.8	-9.4	-1.0%
Less disposals	2.8	2.8	-	-
Modelling adjustment		-26.2		
Net total	**1,338.5**	**1,159.1**	**-179.4**	**-13.4%**

Source: Jemena's revised proposal, AER analysis. Numbers may not sum due to rounding.
Note: Revised proposal figures reflect updates and corrections noted at Table 3.
Within these categories:

- Resilience: Jemena's revised proposal includes $1.3 million for network and community resilience, included in the non-network other category. This is the same amount of resilience expenditure included in our draft decision and $18.5 million (93%) lower than its initial resilience capex proposal.
- Innovation: Jemena's revised proposal includes a $3.4 million innovation allowance, included as augmentation capex. This is $1.9 million (116%) higher than our draft decision and $0.9 million (22%) lower than its initial proposal.
- Cyber security: Jemena's revised proposal includes $6.5 million cyber security within the ICT category. This expenditure was not included in Jemena's initial proposal or our draft decision.

2.5 Operating expenditure

Our final decision is to not accept Jemena's revised total opex forecast of $640.9 million ($2025–26), including debt raising costs, for the 2026–31 period. Our alternative estimate of $602.8 million, including debt raising costs, is $38.0 million or 5.9% lower than Jemena's revised proposal total forecast opex. We consider this is materially different to Jemena's revised proposal. Consequently, we consider that Jemena's total opex forecast does not reasonably reflect the opex criteria.

Our decision is based on a balanced consideration of various factors, including the revised opex proposal from Jemena and stakeholder submissions. We consider our alternative forecast will sufficiently allow a prudent and efficient service provider in Jemena's circumstances to meet the opex objectives.

Table 5 compares our final decision on Jemena's total forecast opex for 2026–31 to its revised proposal.

Table 5 Jemena opex for the period 2026–31 ($million, 2025–26)

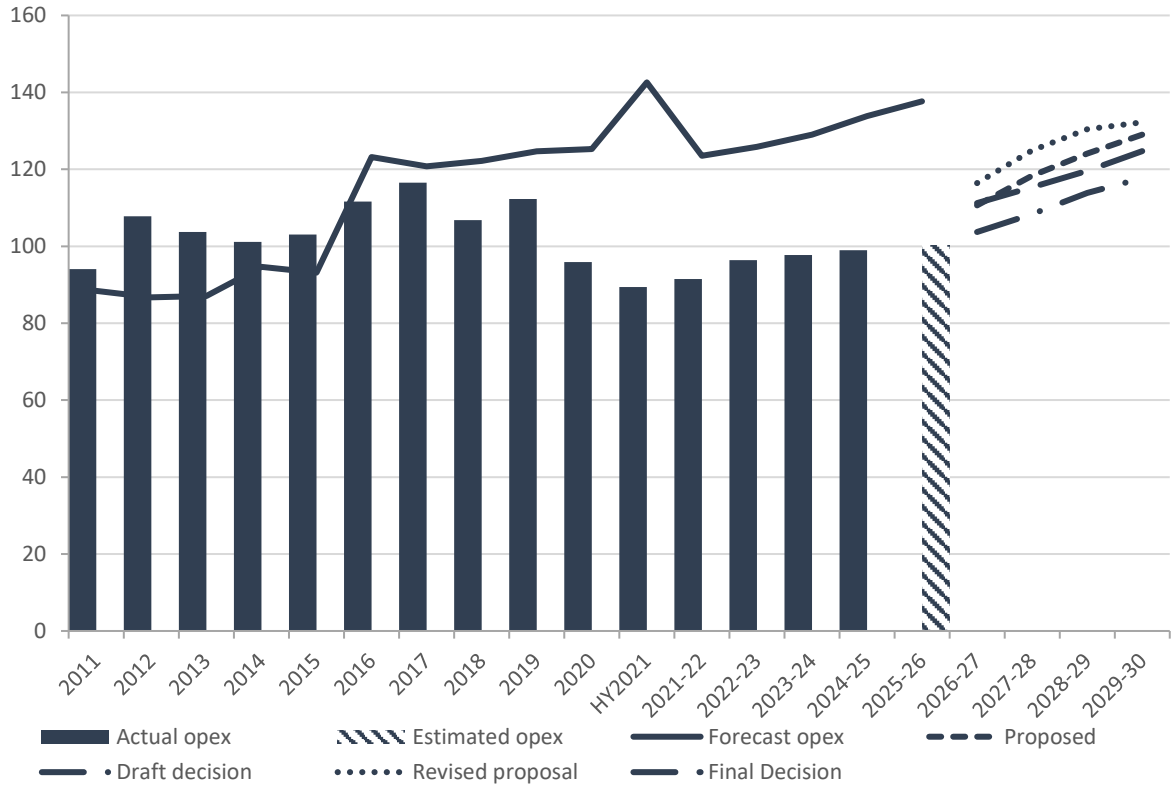
	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Jemena's revised proposal	116.4	124.9	130.4	132.2	136.9	640.9
AER's final decision	111.2	115.4	119.5	124.7	132.0	602.8
Difference ($)	**–5.2**	**–9.6**	**–10.9**	**–7.5**	**–4.8**	**–38.0**
Difference (%)	**–4.5**	**–7.7**	**–8.3**	**–5.7**	**–3.5**	**–5.9**

Source: Jemena, *JEN 2026–31 Proposal - 2025-02-11*; AER, *Attachment 3 - Operating expenditure - Draft decision - Jemena distribution determination 2026–31*, September 2025; Jemena, *JEN 2026–31 Revised Proposal*, December 2025; AER analysis.
Note: Numbers may not add up to total due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

Figure 12 places our final decision opex forecast of $602.8 million in the context of historical opex. Our final decision opex forecast is:

- $47.1 million, or 7.2% lower than the opex forecast we approved in our final decision for the 2021–26 regulatory control period
- $117.9 million, or 24.3% higher than Jemena's actual (and estimated) opex for the 2021–26 regulatory control period.

Figure 12 Jemena's historical and forecast opex ($million, 2025–26)



Source: Jemena, *JEN 2026–31 Proposal - 2025-02-11*; AER, *Attachment 3 - Operating expenditure - Draft decision - Jemena distribution determination 2026–31*, September 2025; Jemena, *JEN 2026–31 Revised Proposal*, December 2025; AER analysis.

Jemena's revised proposal included forecast opex of $640.9 million ($2025–26) over the 2026–31 regulatory control period. This represented an increase of 32.2% compared to its actual and expected expenditure over the 2021–26 period.

Jemena's revised opex proposal also represented an increase of 13.5% compared to our draft decision. In its revised proposal, Jemena:

- proposed a higher revised output growth forecast
- reproposed an increased Information and Communications Technology (ICT) step change
- did not accept our draft decision to not include the Hazard Tree step change
- did not accept our draft decision to include a negative insurance step change
- updated its estimated 2024-25 base year opex with a slightly higher actual amount.

The key differences between our alternative total opex forecast and Jemena's revised proposal are that we have:

- included a lower output growth forecast (–$13.2 million)
- included a lower estimate for the ICT services step change (–$23.8 million)
- not included an amount for the Safety – Low Bushfire Risk Area (LBRA) hazard tree management program step change (–$2.6 million)
- included a negative insurance step change (–$2.6 million).

Our final decision also includes a negative insurance step change (-$2.6 million) to ensure that forecast opex reflects the premiums Jemena will pay in 2025–26 (plus an amount for the rate of change) and meets the opex criteria. However, we note that we have changed our approach from the one we adopted in the draft decision in response to stakeholder feedback and further consideration of the regulatory framework.

Further detail and reasons for our final decision are contained in Attachment 3.

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 post-tax revenue model (PTRM).

Our final decision determines an estimated cost of corporate income tax amount of $149.7 million ($ nominal) for Jemena over the 2026–31 period. This is an increase of $19.2 million (14.7%) from Jemena's revised proposal of $130.5 million. This increase is primarily due to our final decision on higher forecast capital contributions (Attachment 2) paid to Jemena by customers connecting to its network.

Our final decision is to accept Jemena's revised proposal to change the tax treatment for type 1 capital contributions (cash) from large customer connections for the 2026–31 period. As discussed in section 4.4, we consider the change in tax treatment would apply to load customers connecting at 22 kV and above. This would mean that the net tax liability from these connections would be added to the capital contribution amount paid by the connecting

customer for the 2026–31 period. The net tax liability would, therefore, be borne by the connecting customer.

2.7 Revenue adjustments

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

Our final decision includes:

- A revenue adjustment of $13.5 million ($2025–26) under the EBSS. This is higher than Jemena's proposed adjustment (benefit) of $13.2 million ($2025–26). This difference reflects adjustments we have made to account for the latest updates for inflation and the weighted average cost of capital.
- A revenue adjustment of -$33.9 million from the application of the CESS in the 2021–26 period. This is -$0.7 million lower than Jemena's proposed revenue increment amount of -$34.5 million, and reflects that our final decision:
  - updates actual and forecast inflation and rate of return inputs
  - updates actual capital contribution figures to account for auditing
  - updates forecast capex to account for our decision on Jemena's 4 cost pass through applications relating to flexible trading arrangements, the Victorian Emergency Backstop Mechanism 2, accelerating smart meter rollout, and market interface technology enhancement.

Our final decision also includes:

- An allowance of $2.67 million ($2025–26) for the Demand Management Innovation Allowance Mechanism (DMIAM), which comprises a fixed allowance of $0.2 million ($2017), plus 0.075% of the annual revenue requirement for each regulatory year, as set out in our PTRM. Jemena will submit demand management projects for approval under the DMIAM. This allowance is included as a positive adjustment to revenue, and not as capex or opex. This allows any part of the total allowance that is not spent on an approved project to be returned to consumers in the subsequent period.
- A revenue adjustment of –$0.7 million ($ 2025–26) to return revenue earned from unregulated services using shared assets, compared to Jemena's revised proposal of zero. Our final decision sets lower expected revenues than Jemena's revised proposal, and we consider the materiality threshold is met in 2026–27 and 2027–28. This revenue adjustment returns a portion of the unregulated revenue that Jemena earns using shared assets to its consumers.

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.

2.8.1 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 NER prescribed cost pass through events, Jemena proposed to include 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). These 5 cost pass through events will continue to apply for the 2026–31 period.

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

3.1 Capital Expenditure Sharing Scheme

Our final 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.

We updated the CESS in August 2025 and introduced a mechanism which takes the potential for change in forecast connections volumes into account. We also updated the guidelines to allow adjustments to CESS penalties following an ex post review for any additional large bespoke connections, including data centres, that have not been included in a network's proposal. As these adjustments are new additions to the CESS, we sought Jemena's views in its revised proposal on how this adjustment can be applied.

We were not satisfied with Jemena's original revised proposal submission on the operation of the volumetric adjustment for business-as-usual connections. Our concern was that Jemena has not sufficiently disaggregated its connections volumes and expenditure for the purposes of volumetric adjustment. However, following constructive engagement with Jemena, our final decision includes an updated volumetric adjustment approach to make its revised proposal better reflect the intentions of the updated Capital Expenditure Incentive Guidelines. We consider this revised approach is reasonable given Jemena's data recording processes and accept it for the application of the CESS in 2026–31. Details of this updated volumetric adjustment can be found in Attachment 6 to this Final Decision.

We also consider Jemena's definition of large bespoke connections being 22kV and above is reasonable and accept it for the application of the CESS in 2026–31.

We consider the volumetric adjustments and ex post adjustment mechanisms are in the long-term interest of consumers as it reduces any windfall gains and losses associated with forecasting error. Therefore, consistent with our draft decision, we will apply the CESS as set out in the Capital Expenditure Incentives Guidelines (version 4) to Jemena in the 2026–31 regulatory control period.

3.2 Efficiency Benefit Sharing Scheme

Our final 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 standard control services opex and provide for a fair sharing of these between networks and network users.

Consumers benefit from improved efficiencies through lower opex in regulated revenues for future periods.

3.3 Customer Service Incentive Scheme

Our draft decision was to reject Jemena's proposed CSIS for the following reasons:

- insufficient evidence to show that that Jemena's customers strongly supported the adoption of the Jemena's scheme or attribute value to the service improvements specifically proposed by Jemena, and
- Jemena's limited application of its Energy Reference Group's (ERG) feedback on additional CSIS parameters.

In lieu of applying the CSIS, our draft decision was to apply the customer service (telephone answering and new connections) parameters of the Service Target Performance Incentive Scheme.

Jemena's revised proposal reproposed the same CSIS as its initial proposal, claiming that its ERG supported its proposed CSIS. Jemena also questioned the application of the new connections parameter, claiming that it would not apply to the majority of residential and small business customers.

Our final decision is to not apply the CSIS to Jemena as it has not addressed the concerns raised in our draft decision. Instead, we will apply the telephone answering component of the STPIS, but not the new connections parameter, for reasons explained in detail in Attachment 9. While the revised proposal confirmed some of our original assumptions when raising this parameter, based on stakeholder feedback, we will not activate the new connections parameter of the STPIS in the 2026–31 period.

3.4 Service Target Performance Incentive Scheme

Jemena accepted our draft decision to apply version 2.0 of the STPIS for the 2026–31 regulatory control period, but with several clarifications:[30]

- *Customer service component (telephone answering parameter):* Jemena proposed that the telephone answering parameter should not apply in the forthcoming regulatory period and that it should be replaced with the CSIS. Our final decision is to apply the telephone answering parameter. This is discussed further in section 3.4.1.
- *Customer service component (new connections parameter):* Jemena did not accept the application of the new connections parameter of the customer service component. Our final decision is to not apply the new connections parameter of the STPIS (see Attachment 9 to this final decision).
- *Revenue at risk:* Jemena proposed to apply revenue at risk of ±4.5% for the STPIS, reflecting the inclusion of its proposed CSIS. Our final decision is to set revenue at risk

[30] Jemena, *2026–31 Electricity Distribution Price Review - Revised Regulatory Proposal – Attachment 07-01*, December 2025, p 12.

within the default range of ± 5%, as we did not accept Jemena's CSIS. This is discussed further in section 3.4.3.

3.4.1 Telephone answering parameter

Given our final decision does not accept Jemena's proposed CSIS, we will instead apply the STPIS telephone answering component. While not a long-term solution, this parameter delivers some incentivised customer service benefits in the absence of a CSIS.

Table 6 and Table 7 show the STPIS customer service (telephone answering) performance target and incentive rate applicable to Jemena in the 2026–31 period.

3.4.2 Performance Targets and incentive rates for the 2026–31 period

Clause 3.2.1(a) of version 2.0 of the STPIS specifies that the performance targets to apply during the regulatory control period must not deteriorate across regulatory years.

In accordance with the scheme[31], our final decision is to set Jemena's performance targets based on average performance over the past 5 regulatory years. We have calculated these targets based on annual performance data provided by Jemena. We have also updated the incentive rates and Value of Customer Reliability (VCR) as a result of updates to the final revenue numbers and the CPI.

Table 6 and Table 7 present our final decision on the applicable performance targets and incentive rates that will apply to Jemena for the 2026–31 period. We have applied the VCR for urban and short rural network segments set out in Table 8 to calculate Jemena's incentives rates for the 2026–31 period.

Table 6 Final decision – Jemena's STPIS performance targets for 2026–31 period

	Urban	Short Rural	Telephone answering
SAIDI (minutes)[32]	44.2343	42.8786	N/A
SAIFI (interruptions)[33]	0.6963	0.6555	N/A
MAIFI (interruptions)[34]	1.0102	1.0137	N/A
Customer service - telephone answering (%)[35]	N/A	N/A	76.37

Source: AER analysis.

31 STPIS Version 2.0, cl 3.2.1.

32 System Average Interruption Duration Index (SAIDI).

33 System Average Interruption Frequency Index (SAIFI).

34 Momentary Average Interruption Frequency Index (MAIFI).

35 Percentage of total calls to the fault line answered in 30 seconds. Time to answer a call is measured from when the call enters the call centre telephone system and is answered by a human operator.

Table 7 Final decision – Jemena's STPIS incentive rates for 2026–31 period

	Urban	Short Rural	Telephone answering
ir – SAIDI	0.0679	0.0090	N/A
ir – SAIFI	2.8745	0.3946	N/A
ir – MAIFI	0.2300	0.0316	N/A
Customer service - telephone answering (%)	N/A	N/A	-0.04

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

Table 8 Value of customer reliability ($/MWh)

	Urban	Short Rural
VCR	35,857	35,857

Source: AER, Values of customer reliability – Final report on VCR values, December 2024, Table 20 NEM-wide and regional VCR.

3.4.3 Revenue at risk

Revenue at risk caps the potential reward and penalty for Jemena under the STPIS. As discussed above and in Attachment 9, our final decision is to not accept Jemena's proposed CSIS, and to instead apply the customer service (telephone answering) component of the STPIS.

Unless a DNSP proposes otherwise, the maximum revenue at risk for individual customer service parameters is ±0.5%. In the absence of the new connections parameter, our final decision is to apply a revenue at risk of ±0.5% for the customer service (telephone answering) component of the STPIS.[36]

3.5 Demand Management Incentive Scheme and Demand Management Innovation Allowance Mechanism

Our final decision is to apply the DMIS and DMIAM to Jemena in the 2026–31 regulatory control period. The DMIS provides network service providers with financial incentives for undertaking efficient demand management activities. The DMIAM funds research and development in demand management projects that have the potential to reduce long-term

[36] AER, STPIS Version 2.0, November 2018, clause 5.2(a) and (b)

network costs. This approach is consistent with Jemena's revised proposal,[37] and our draft decision on DMIS and DMIAM.[38]

3.6 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.[39] We will continue to adopt our current approach to give effect of the outcomes of the scheme as an 'I-factor' component within the price control formula.

37 JEN, *RP - Att 07-01 - Incentive mechanisms - 20251201 – Public,* December 2025, p iv.

38 AER, *Attachment 8 - DMIS and DMIAM - Draft decision - Jemena distribution determination 2026–31*, September 2025.

39 Victoria, *Gazette: General*, No G 51, 22 December 2016, p 3239.

4 Network pricing

4.1 Service classification

Our determination for Jemena separates the regulated distribution 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 Jemena in 2026–31 in our Framework and Approach paper in July 2024, 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.

In recognition of material changes in circumstances since the Framework and Approach paper was published, our final decision makes the following changes to the service classifications set out in the Framework and Approach:

- Type 9 metering services, if required to be provided by a Victorian DNSP upon request by a public lighting customer in relation to a public lighting asset pursuant to an Order made under sections 15A and 46D of the Victorian *Electricity Industry Act 2000*[40] as in force from time to time, will be classified as direct control services and then as alternative control services within the existing public lighting service group.
- Distribution asset rental for electric vehicle charging infrastructure, and the facilitation of distribution asset rental for this infrastructure, will be classified as negotiated distribution services. Facilitation of this new, negotiated distribution service will be excluded from the existing shared asset facilitation service that forms part of the standard control, common distribution service.

We do not directly regulate the prices, terms and conditions of access to negotiated distribution services. The effect of a negotiated service classification is that, for the 2026–31 period, negotiations between Jemena and parties seeking access to Distribution asset rental for electric vehicle charging infrastructure will be subject to:

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40 Consultation by the Victorian Department of Energy, Environment and Climate Action (DEECA) on amendments to the *Advanced Metering Infrastructure (Obligations to Install Meters) Order 2017* (made under sections 15A and 46D of the *Electricity Industry Act 2000*, gazetted on 10 October 2017) closed in February 2026. Publication of the *Advanced Metering Infrastructure (Obligations to Install Meters) Order 2026* is expected to occur in May 2026.

- 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 and outcomes, and must be applied by DNSPs in negotiating terms and conditions of access, including prices and access charges.

We will apply those same principles in arbitration of access dispute between a DNSP and a service applicant as to the terms and conditions of access to a direct control service or to a negotiated distribution service.

The Negotiating Framework and NDSC for the 2026–31 period are discussed in Attachment 17 to this final decision.

4.2 Tariff structure statement

Our final decision is to make 2 amendments to Jemena's revised TSS to make it compliant with the NER.[41] We are satisfied that with these amendments, Jemena's TSS complies with the pricing principles for direct control services and other applicable requirements of the NER.

Jemena's revised TSS for the 2026–31 period is its third since the AEMC's *Distribution Network Pricing Arrangements* rule change in 2014 that introduced the tariff structure statement framework.[42] This TSS is also Jemena's first since the AEMC's 2021 *Access, pricing and incentive arrangements* rule change that allowed for two-way pricing.[43] Together these rule determinations introduced several reforms to distribution pricing, including to progress cost reflective pricing and to support more CER onto the network. Jemena's 2026–31 TSS will apply from 1 July 2026 and remain in effect until the end of the regulatory period.

We assess TSSs against the requirements of the NER and NEL, including the pricing principles and other applicable requirements of the NER. The assessment includes whether the network tariffs progress towards better reflecting network costs,[44] or progress network tariff reform. Network tariff reform enables distributors to charge retailers in a manner which more closely reflects the cost of providing electricity network capacity to end-use consumers and can support the energy transition currently underway. Where price signals are passed through by retailers, 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.

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

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

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

44 NER, cl 6.18.5(a).

Our draft decision emphasised that Jemena should consider the extent that well-designed network tariffs can shift future demand growth out of peak periods and into low/minimum demand periods. Our final decision also flags that we expect Jemena to continue to consider the links between TSSs, expenditure and the capacity of network tariffs, along with non-network strategies like demand management and control, to permanently shape customer load and support efficient use of the network in its fourth TSS.

In making our final decision, we have considered that under the pricing principles, tariffs may vary from those complying with the economic pricing principles to the extent permitted by the NER.[45] That is, to consider the pricing principles relating to customer impacts and retailer ability to incorporate tariffs in a retail offer and/or customer understandability. Such tariffs comply with the NER and other applicable regulatory instruments. We are also required to make our decisions in a manner that will or is likely to contribute to the achievement of the NEO.

While an indicative pricing schedule must accompany the TSS, the price levels for each tariff for each year of the 2026–31 period are not set as part of this determination. Annual prices are subject to a separate, annual pricing process each year of the regulatory period.

4.2.1 Our final decision and its context

We approved many elements of Jemena's initial TSS in our draft decision. This included the introduction of a solar soak tariff for residential customers (a time-of-use tariff with very low consumption charges between 11am and 4pm) to replace its existing default time-of-use tariff, and the structure of Jemena's proposed individually calculated tariff. Attachment 13 of our draft decision sets out our reasons for approving those elements. We do not repeat them in our final decision. Rather, our final decision focuses on:

- Jemena's response to our draft decision – for example, we required Jemena's revised TSS to include better supporting information for its proposed 1kWh/day basic export levels and LRMC input forecasts based on at least a 10-year period
- any changes between Jemena's initial TSS and its revised TSS
- submissions in response to our draft decision and/or Jemena's revised TSS.

We consider that Jemena has largely responded to our draft decision. Our final decision is to amend Jemena's revised TSS only to the extent necessary to make it compliant with the NER.[46] We are satisfied that, with the following amendments, Jemena's TSS complies with the requirements of the NER, the NEL and contributes to achieving the NEO:[47]

- include information on the eligibility, assignment policies and tariff setting process for Jemena's site-specific tariffs (this information is currently in Jemena's tariff structure explanatory statement but not in its TSS)
- include further information on the eligibility and price setting process for Jemena's LV (low voltage) storage tariff

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45 NER, cl 6.18.5(c).

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

47 NER, cl 6.12.3(k) and NEL, s 7.

These amendments complement the changes Jemena made in its revised TSS in response to our draft decision. The changes included:

- providing additional information on how it had regard to network intrinsic hosting capacity in proposing 1 kWh/day basic export levels for its proposed two-way tariff
- including bill impact analysis demonstrating that most small customers will be better off by reassignment from withdrawn demand tariffs to time-of-use tariffs
- providing additional information on eligibility for the site-specific tariff (including the approach it will take in setting each site-specific tariff), assignment and pricing methodology
- extending the LRMC input forecasts to 10 years and providing further explanation of forecast demand driving expenditure
- changing the name of its unmetered supply tariff to 'public lighting and street furniture' tariff and clarifying that it would be available to both type 9 and 7 metered load, but only to load that is considered public lighting and street furniture.

Jemena proposed the following additional changes in its revised TSS (changes not in response to our draft decision):

- removal of the solar soak and export components of its proposed LV large business storage tariff.

Submissions covered a range of views on specific network tariff structures, assignment policies and progress on network tariff reform. Submissions generally supported the progress of network tariff reform in Victoria (including introduction of solar soak periods and optional two-way tariffs), noting that some submissions supported further consistency between the Victorian distributors' two-way pricing tariffs.[48] Submissions also noted that Victorian distributors are somewhat constrained in progressing tariff reform because the Victorian Government does not support the mandatory assignment of small customers to cost reflective tariffs. Multiple submissions also encouraged Jemena to introduce a 24-hr controlled load tariff trial.[49]

A number of submissions highlighted the need for considered and coordinated education on tariffs in the context of an evolving tariff environment in Victoria. For example, the CCP32's feedback supported a joint tariff information campaign between Victorian distributors, retailers and the Government.[50] Similarly, Jemena's Energy Reference Group (ERG) noted

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48 AGL, *Submission on Victorian electricity distribution proposals 2026–31*, January 2026, p 1; Hon Lily D'Ambrosio MP, *Submissions on Victorian electricity distribution proposals 2026–31*, January 2026, pp 1–2.

49 AGL, *Submission on Victorian electricity distribution proposals 2026–31*, January 2026, p 1; Jemena Energy Reference Group, *Feedback to AER on Jemena Electricity Networks distribution 2026–31 Draft Decision*, December 2025, p 5.

50 CCP32, *AusNet Revised Regulatory Proposal and Draft Decision Advice 2026–31*, January 2026, pp 22–23; CCP32, *Jemena Revised Regulatory Proposal and Draft Decision Advice 2026–31*, January 2026, p 11; CCP32, *CitiPower Revised Regulatory Proposal and Draft Decision Advice 2026–31*, January 2026, p 20; CCP32, *Powercor Revised Regulatory Proposal and Draft Decision Advice 2026–31*, January 2026, p 22; CCP32, *United Energy Revised Regulatory Proposal and Draft Decision Advice 2026–31*, January 2026, p 22.

and urged the AER to clarify who is responsible for this education.[51] While these submissions are aimed at Jemena and AusNet, we consider they are relevant to all Victorian distributors. This is discussed further in section 13.1.3 of our final decision Attachment 13.

Submissions on Jemena's proposed storage tariff were mixed. AGL supported Jemena's $/year fixed charges over CitiPower, Powercor and United Energy's proposed capacity charges to recover residual costs.[52] However, the Victorian Government submitted that Jemena's fixed charge ($3,585/annum), while slightly reduced since the initial TSS, remained high.[53]

There were also multiple submissions that commented on the Victorian distributors' kerbside EV tariff trials which they will run over the 2026–31 period. The submissions generally supported EV tariff trials but advocated for eligibility for the trials to be broadened, for example, submissions from Nexa Advisory, Evie Networks, AGL and the Victorian Government.[54] The Victorian Government also emphasised that any such trials should still be cost reflective.

While we do not have a role in approving or assessing tariff trials, our final decision Attachment 13 notes that if the Victorian distributors were to propose these trials as full tariffs in their TSSs for the 2031–36 period, we would then assess them against the pricing principles and other applicable requirements of the NER. We would only approve tariffs that complied with the NER's distribution pricing principles and other NER requirements. This is discussed in Appendix A of our final decision Attachment 13.

In consideration of submissions, our final decision:

- approves Jemena's proposed two-way tariff. We have not required further consistency between the Victorian distributors' two-way tariffs, for example requiring Jemena and AusNet to introduce seasonal components in their tariffs to match CitiPower, Powercor and United Energy's. We consider that the distributors have achieved *some* consistency by having the same basic export levels of 1/kWh per day and solar soak windows. However, we acknowledge that they have maintained differences to reflect differences in their networks
- amends Jemena's revised TSS to include further transparency on its storage and site-specific tariff. We have not required Jemena to decrease the *levels* of its fixed charge because Jemena's storage tariff is intentionally discounted relative standard business tariffs and its fixed charge appropriately recovers residual costs
- encourages Jemena to engage with the other Victorian distributors, retailers and the Victorian government to undertake communication and engagement to build customers'

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51 Jemena Energy Reference Group, *Feedback to AER on Jemena Electricity Networks electricity distribution proposals 2026–31*, January 2026, p 5.

52 AGL, *Submission on Victorian electricity distribution proposals 2026–31*, January 2026, p 1.

53 Hon. Lily D'Ambrosio MP, *Submission on Victorian electricity distribution proposals 2026–31*, February 2026, p 7.

54 Nexa Advisory, *Submission on Victorian Electricity distribution proposals 2026–31,* January 2026, pp 7–10; Evie Networks, *Submission on Victorian Electricity distribution proposals 2026–31,* January 2026, pp 3–6; AGL, *Submission on Victorian electricity distribution proposals 2026–31*, January 2026, p 3; Hon. Lily D'Ambrosio MP, *Submission on Victorian electricity distribution proposals 2026–31*, February 2026, pp 6–7.

understanding of tariffs. However, we consider that any joint engagement or communication should focus on how customers can understand, respond to and benefit from *retail* tariffs and signals, rather than network tariffs. This is because customers are not directly exposed to network tariffs, and it is the retail offer that customers can see and potentially respond to.

- explains the trial tariff framework and encourages the Victorian distributors to engage in tariff trials for a broader range of EV charging load during the 2026–31 period.

In our final decision Attachment 13 we describe our assessment of Jemena's revised TSS. Attachment 13 of our final decision is to be read alongside Attachment 13 of our draft decision, in which we approved (and explained the reasons for the approval of) many elements of Jemena's initial TSS. Alongside Attachment 13, we publish marked up and clean versions of Jemena's revised tariff structure statement.

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 did not accept Jemena's public lighting proposal. We made several adjustments, including for replacement cycles, the volume of smart lighting cells, pole inspection rates, labour rates, inflation and labour price growth. We also encouraged Jemena to consult further with stakeholders on its accelerated LED rollout and smart lighting services.

In its revised proposal, Jemena proposed to fully fund the accelerated LED rollout, removing the council-funded LED tariffs, and revised its approach for smart lighting services. Jemena also did not accept our draft decision to increase its pole inspection rate and provided additional information to justify this.

The Victorian Greenhouse Alliances' submission while supportive of the Victorian DNSP's accelerated LED rollouts raised some specific concerns in relation to Jemena. This included that some councils had already fully rolled out / funded their LED lights and under Jemena's revised proposal would be cross-subsiding other councils' LED rollouts. Additionally, the Victorian Greenhouse Alliance recommended Jemena introduce a separate 'Opt-in smart lighting' tariff for residential roads. This was so councils who do not choose to adopt residential road smart lighting do not cross subsidise councils who do make this choice.

In response to these concerns, and ongoing consultations, Jemena proposed to reintroduce the council-funded LED tariff and proposed separate opt-in LED tariffs for residential roads. Both changes were to minimise / remove any cross subsidisation between councils.

Our final decision is to not accept Jemena's public lighting proposal because although we consider the changes it has proposed are largely reasonable, there are some aspects where we consider require adjustments. In our final decision, we have made several mechanical changes related to update inflation, the weighted average cost of capital and labour price growth. We also maintain our draft decision for the pole inspection rate as we do not consider Jemena's method for its pole inspection is efficient. In addition, our final decision to

classify type 9 metering services as alternative control services means that the costs as proposed by Jemena are included in public lighting prices.

Our final decision public lighting prices for 2026–27 are, on average 0.5% lower compared to Jemena's updated revised proposal and 26.9% lower compared to Jemena's original revised proposal.

Our final decision on public lighting is discussed further in Attachment 14.

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 did not accept Jemena's metering proposal. We applied a different approach to replacing meters ending the end of their lives and made several adjustments to its forecast metering capex. We encouraged Jemena to consider and respond to these changes in its revised proposal and to incorporate the outcomes of any further stakeholder engagement it undertakes.

In its revised proposal Jemena did not accept our draft decision for metering services. While proposing proactive replacement of meter services, it proposed higher replacement volumes than in our draft decision. It also proposed increases for related activities such as meter disposals, for new activities including site scoping and outage notifications, wasted visits, and panel and wire remediation works, as well as for increased program support for the proactive replacement approach and the increased replacement volumes.

We received a submission from Jemena's Energy Reference Group, supporting the proposed proactive replacement approach for its operational efficiency and cost savings relative to the inspection-led approach from Jemena's original proposal.

Our final decision is to not accept Jemena's revised proposal on metering services. Our final decision reinstates our draft decision proactive replacement volumes, adjusts related activities for these volumes, removes panel and wire remediation works, and reduces the proposed program support capex. Our final decision also makes other changes to how expenditures are recovered and making mechanical changes related to updated inflation, the rate of return, and labour escalation inputs.

Our final decision on metering services is discussed further in Attachment 15.

4.4 Connection policy

As detailed in our draft decisions Victorian DNSPs' connection policies generally aligned with the requirements of the NER, with all DNSPs adopting enhancements following engagement on their initial proposals.

Our draft decisions recognised that the continued strong growth in data centre connections could lead to a growing cross subsidy of the tax costs associated with type 1 capital contributions from very large customers. We asked DNSPs to consider whether the net tax liability arising from type 1 capital contributions could be included as part of the upfront

connection cost paid directly by the customer, rather than recovered from all customers through distribution use of system charges.

In response to our draft decisions all 5 Victorian DNSPs agreed to recover tax associated with type 1 capital contributions upfront but considered it should apply to all customers above a defined threshold, not just data centres.

All DNSPs proposed the application of upfront tax recovery to all large customers above a given threshold. However, each proposed different thresholds above which a newly connecting customer would, in addition to its upfront capital contribution, be charged upfront the tax costs associated with the capital contribution.

Our final decisions adopt a consistent threshold of ≥22 kV for load customers. This threshold limits the currently tax cross subsidy that occurs when large connections, like data centres, connect to the distribution network. The threshold is fair, provides certainty and ensures alignment across Victorian DNSPs.

For consistency and neutrality between DNSPs we considered a threshold of 1.5MW should apply to embedded generators for upfront recovery of tax costs associated with type 1 capital contributions. This is consistent with our decision on AusNet's Connection Policy for the current, 2021–26 period.

5 Constituent decisions

In accordance with clause 6.12.1 of the NER, this final decision on the distribution determination that will apply to Jemena for the 2026–31 period is predicated on the following decisions by the AER (constituent decisions):

Table 9 Constituent decisions

NER cl 6.12.1	Constituent decision
6.12.1(a)	The AER's final decision is that the classification of services set out in Attachment 11 to this final decision will apply for the 2026–31 regulatory control period.
6.12.1(b)(1)	The AER's final 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 final decision on the annual revenue requirement for each regulatory year of the 2026–31 regulatory control period is set out in Attachment 1 to this final decision.
6.12.1(b)(2)	The AER's final decision is to approve the commencement and length of the regulatory control period as proposed in the building block proposal. The AER's final 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 final decision is not to accept the total of the forecast capital expenditure for the 2026–31 regulatory control period that is included in the current building block proposal. The AER's final decision therefore sets out an alternative estimate of the total of the required capital expenditure for the regulatory control period that the AER is satisfied reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors, of $1,159.1 million ($2025–26), and reasons for that decision, in Attachment 2 to this final decision.
6.12.1(c1)	The AER's estimate of the total of the required capital expenditure under clause 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 final decision is not to accept the total of the forecast operating expenditure for the 2026–31 regulatory control period that is included in the current building block proposal. The AER's final decision therefore sets out an alternative estimate of the total of the required operating expenditure for the regulatory control period that the AER is satisfied reasonably reflects the operating expenditure criteria, taking into account the operating expenditure factors, of $602.8 million ($2025–26), and reasons for that decision, in Attachment 3 to this final decision.

NER cl 6.12.1	Constituent decision
6.12.1(d1)	Jemena did not propose any contingent projects and therefore the AER has not made a decision under clause 6.12.1(d1) of the NER.
6.12.1(e)	The AER's final decision on the allowed rate of return for the 2026–27 regulatory year is 6.17% (nominal vanilla). 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.
6.12.1(e1)	The AER's final decision on the allowed imputation credits for each regulatory year or the 2026–31 regulatory control period is 0.57.
6.12.1(f)	The AER's final 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 $2,189.7 million ($nominal). The reasons for the AER's decision are set out in Attachment 1 to this final decision.
6.12.1(g)	The AER's final decision on the estimated cost of corporate income tax to Jemena for each regulatory year of the 2026–31 regulatory control period, in accordance with clause 6.5.3 of the NER, is set out in Attachment 1 to this final decision.
6.12.1(h)	The AER's final decision is not to approve the depreciation schedules submitted by Jemena. The AER has therefore determined depreciation schedules in accordance with clause 6.5.5(b) of the NER, as set out in Attachment 1 to this final decision.
6.12.1(i)	The AER's final decision on how applicable incentive schemes are to apply to Jemena in the 2026–31 regulatory control period is: • Version 2 of the Efficiency Benefit Sharing Scheme will apply, for the reasons set out in Attachment 5 to this final decision. • Version 4 of the Capital Expenditure Sharing Scheme will apply, for the reasons set out in Attachment 6 to this final decision. • Version 2 of the Service Target Performance Incentive Scheme (including the customer service component) will apply, for the reasons set out in Attachment 7 to this final decision. • Version 1 of the Demand Management Incentive Scheme will apply, for the reasons set out in Attachment 8 to our draft decision. • Version 1.01 of the Demand Management Innovation Allowance Mechanism will apply, for the reasons set out in Attachment 8 to our draft decision. • A small scale incentive scheme (Customer Service Incentive Scheme) will not apply, for the reasons set out in Attachment 9 to this final decision.
6.12.1(j)	The AER's final decision is that all other appropriate amounts, values and inputs are as set out in this final decision, including in supporting models and attachments.

NER cl 6.12.1	Constituent decision
6.12.1(k)	The AER's final decision on the form of the control mechanism (including the X factor) for standard control services is, in accordance with the Framework and Approach Paper, a revenue cap. The AER's final decision on the formulae that give effect to those control mechanisms is set out in Attachment 12 to this final decision.
6.12.1(l)	The AER's final 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 final decision on the formulae that give effect to those control mechanisms is set out in Attachment 12 to this final decision.
6.12.1(m)	The AER's final 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 to this final decision.
6.12.1(n)	The AER's final decision is that the following additional pass through events are to apply for the 2026–31 regulatory control period in accordance with clause 6.5.10: • insurance coverage event • insurer credit risk event • terrorism event • natural disaster event • retailer insolvency event. These events have the definitions set out in Attachment 4 to our draft decision.
6.12.1(n1)	The AER's final decision is to refuse to approve the tariff structure statement proposed by Jemena. In accordance with clause 6.12.3(l) our final decision therefore includes an amended tariff structure statement. Amendments and reasons for our final decision are set out in Attachment 13 of this final decision.

NER cl 6.12.1	Constituent decision
6.12.1(o)	The AER's final decision is that a variant of the negotiating framework as proposed by Jemena, as set out in Attachment 17 to this final decision, is to apply to Jemena for the 2026–31 regulatory control period.
6.12.1(p)	The AER's final decision is that the Negotiated Distribution Service Criteria set out in Attachment 17 to this final decision will apply to Jemena for the 2026–31 regulatory control period.
6.12.1(q)	The AER's final 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 of our draft decision.
6.12.1(r)	The AER's final decision is that depreciation for establishing the regulatory asset base as at the commencement of the following 2026–31 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 to this final decision.
6.12.1(s)	The AER's final decision on how Jemena is to report to the AER on its recovery of designated pricing proposal charges for each regulatory year of the 2026–31 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 to this final decision.
6.12.1(t)	The AER's final 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 2026–31 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 to this final decision. This final decision applies to each jurisdictional scheme under which Jemena has jurisdictional scheme obligations at the time of this final decision.
6.12.1(u)	The AER's final decision is that a variant of the connection policy as proposed by Jemena, set out in Attachment 16 to this final decision, is to apply to Jemena for the 2026–31 regulatory control period.
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',[55] the AER's final 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 to this final decision.

[55] Victoria, *Gazette: General*, No G 51, 22 December 2016, p 3239.

6 List of submissions

We received 11 submissions in response to our draft decision and Jemena's 2026–31 revised proposal.

	Date
AER Consumer Challenge Panel (CCP32)	January 2026
AGL	January 2026
Ausgrid	January 2026
Dean Lombard and Gavin Dufty	January 2026
Evie Networks	January 2026
Hon Lily D'Ambrosio MP	January 2026
Jemena Energy Reference Group	December 2025
Nexa Advisory	January 2026
Red Energy and Lumo Energy	January 2026
Save our Surroundings Riverina	January 2026
Victorian Greenhouse Alliances	January 2026

7 Shortened forms

Term	Definition
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
augex	augmentation expenditure
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
RBA	Reserve Bank of Australia
Repex	replacement expenditure

Term	Definition
RORI	rate of return instrument
SCS	standard control services
STPIS	Service Target Performance Incentive Scheme
TSS	tariff structure statement
WACC	weighted average cost of capital