Final decision

Jemena Gas Networks (NSW) access arrangement 2025 to 2030

(1 July 2025 to 30 June 2030)

Overview

May 2025

AUSTRALIAN ENERGY REGULATOR

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List of attachments

This Overview forms part of our final decision on the access arrangement that will apply to Jemena Gas Networks (JGN) (NSW) for the 2025–30 access arrangement period. It should be read with all other parts of this final decision.

For some issues that had draft decision attachments, and which were settled at the draft decision stage or required only minor updates, the reasons in the draft decision attachments and, where relevant, in the final decision Overview set out our reasons for our final decision on the issue.

In these circumstances, we have not prepared all attachments, and 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.

This final decision includes the following attachments:

Attachment 2 – Capital base

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 9 – Reference tariff setting

Attachment 10 – Reference tariff variation mechanism

Attachment 12 – Demand

Attachment 13 – Capital expenditure sharing scheme

Executive summary

The Australian Energy Regulator (AER) exists to ensure energy consumers are better off, now and in the future. Consumers are at the heart of our work, and we focus on ensuring a secure, reliable, and affordable energy future for Australia as we transition to net zero emissions. The regulatory framework governing gas transmission and distribution networks is the National Gas Law and Rules (NGL and NGR). Our work is guided by the National Gas Objective (NGO).

As a regulated business, the New South Wales (NSW) gas distribution network service provider, Jemena Gas Networks (JGN) must periodically apply to us for a ruling on network charges. This is submitted in the form of an access arrangement specifying the services it will provide, the tariffs for those services, and the other terms and conditions on which they will be provided. On 29 June 2024, we received JGN's proposal for the 1 July 2025 to 30 June 2030 access arrangement period (2025–30 period). We have now consulted on that proposal, our draft decision, and a revised proposal from JGN in response to our draft decision.

Our assessment of JGN's revised proposal

We do not approve JGN's revised access arrangement, and our final decision is to allow JGN to set gas network charges resulting in the recovery of an expected $3,106.7 million ($nominal, smoothed) in revenue from consumers over the 2025–30 period. This is a decrease of $139.7 million (4.3%) from JGN's revised proposal.

Compared to the current access arrangement period, the impact of our final decision is an increase of $394.2 million (16.0%) in real smoothed revenue. There are several drivers of this outcome. The return on capital over the 2025–30 period is higher than the 2020–25 period, providing JGN with an increase of $261.7 million (29.8%). This increase for our final decision is related to changes in market variables outside of JGN's control, including a higher rate of return and higher expected inflation compared to the 2020–25 period. JGN's corporate income tax allowance is $54.1 million higher than the 2020–25 period, primarily due to a higher return on equity and lower tax depreciation. Revenue adjustments are $254.5 million higher than the 2020–25 period, due to the expiry of a one-off large negative revenue adjustment for the 2015–20 remittal decision and the impact of capital and operating expenditure (capex and opex) incentive schemes.

Key elements of our final decision include:

- Reducing JGN's revised accelerated depreciation from $230 million to $115 million ($2024-25), determined by applying a 'base' real price increase limit of 0.5% for the 2025–30 period.[1]
- Reducing JGN's revised total capex to include a total capex forecast of $717.4 million ($2024–25), a reduction of $120.7 million (14%). We have not accepted JGN's revised forecast of $78.9 million to fund renewable gas connections.
- We have increased JGN's revised customer connections capex by $35.0 million, net of capital contributions (JGN proposed $276.5 million) driven by our forecast of a higher

[1] The 'base' price path means annual real price increases without accounting for the impact of incentive schemes.

rate of residential customer growth than JGN's forecast. While this leads to an expectation of more residential customer connections and more capex, it has a slight downward impact on bills, given it will increase forecast gas consumption.

- Approving total forecast opex of $1,144.9 million ($2024–25), including abolishment costs. This is slightly ($3.6 million) lower than JGN's revised proposal due to our lower estimate of socialised abolishment costs.
- Approving JGN's proposed hybrid tariff variation mechanism for its gas transportation reference service, incorporating elements of both weighted average price cap and revenue cap regulation. The hybrid mechanism reduces JGN's incentive to grow the volume of gas carried by its network while mitigating year-on-year tariff volatility associated with revenue caps.
- Approving JGN's proposed tariff changes to flatten its volume (small) customer declining block tariff structure for gas transportation. Our final decision on this issue and on JGN's hybrid tariff variation mechanism both reflect the updated NGO which now incorporates an emissions reduction element. We accept JGN's proposal to engage its demand customers and stakeholders on future reforms to its declining block tariff for demand (large) customers.
- Reducing JGN's proposed volume (small) customer abolishment tariff from $1,472 to $1,200.60 to align with other networks, and socialising most of that cost across all customers to reduce the tariff to $250. Reducing the price gap between temporary and permanent disconnection services is aimed at addressing safety concerns consistent with the view of the NSW safety regulator.
- Updates for movements in market variables such as interest rates, bond rates and expected inflation in recent months, the net effect being an increase to the return on JGN's capital base.

Future gas demand uncertainty

With the energy transition underway and given the Australian and NSW Governments' goals of reaching net zero emissions by 2050, there are complex questions about the future of gas networks. For example, our information paper *Regulating gas pipelines under uncertainty* asked whether developments in the energy transition mean that it may no longer be in gas consumers' long-term interest to allow further growth in the gas networks.[2]

The uncertainty for JGN about how the energy transition will impact its network means there are several options for managing its future. For example, JGN's proposal to invest in new renewable gas connections is one strategy it has taken to manage its changing operating environment.[3]

JGN's intention to maintain demand for its network is important. The March 2025 *Gas Statement of Opportunities* delivered by the Australian Energy Market Operator forecast falling demand for gas in NSW.[4] Declining demand for gas network services is the most significant expected driver of future rising gas network prices. As customers leave the gas network, there will be fewer customers to share the fixed costs of providing gas network services. Further new investments in the network for long-lived assets now, mean that if

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2 AER, *Regulating gas pipelines under uncertainty information paper*, November 2021, p. 59.

3 JGN, *Revised 2025 Plan,* January 2025, p. 13.

4 AEMO, *Gas Statement of Opportunities 2025*, March 2025.

customers continue to leave the network the financial burden carried by remaining customers will be exacerbated.[5]

We have heard from stakeholders on both sides of this issue, with industrial customers expressing support for investing now to developing renewable gas supply, while consumer advocates have expressed concern about the potentially worsening asset stranding risk, with that risk inherently being transferred to consumers.

After significant consideration, our final decision is to not accept JGN's revised capex for the 2025–30 period, and to substitute an alternative estimate of $717.4 million ($2024–25). This is $120.7 million or 14% lower than JGN's revised proposal. Our lower forecast is largely driven by reducing JGN's proposed meter replacement capex by $49.7 million and not accepting JGN's proposed $78.9 million in proposed renewable connections to connect biomethane production facilities to JGN's network. Partially offsetting those reductions is our final decision to increase JGN's customer connections capex, reflecting our higher forecast of residential customer connection growth.

Uncertainty in the external environment has been taken into account in our consideration of several elements of our final decision. For JGN's renewable connection projects, we accept that, if completed and supplied as specified, these projects are likely to provide a net benefit. However, we remain concerned there is significant commencement and completion risk for these projects. Our decision reflects that currently there is significant uncertainty relating to the investments, and an important question of who bears the risk of funding these investments.

We acknowledge the work undertaken by JGN to respond to our draft decision concerns on its proposed renewable connections. While we have not approved capex to undertake those connections, our decision does not prevent JGN from undertaking this capex in the access arrangement period, and seeking to either have the capex assessed as part of the opening capital base for the next period (2030–35), or by using the speculative capex account. Given the existing uncertainty around biomethane suppliers undertaking their own necessary investment to connect to JGN's network, we consider this approach better balances the risk faced by other customers of financing JGN's investment.

Accelerated depreciation of gas network assets

The national gas regime is not well equipped to deal with a network in decline and was developed at a time when the gas market was growing and was expected to continue to expand. Since then, the market has begun to evolve in ways unforeseen when the rules were developed. Stakeholders have indicated concerns regarding the current national gas regulatory framework, and the impact that it has in making decisions for the future.

As noted in our draft decision, addressing the broader issues in the gas sector requires a holistic policy response. While accelerated depreciation can be used as a tool for reducing asset stranding risk, it has limitations and on its own cannot resolve the issues faced by the gas networks and customers from anticipated declining demand. Declining demand is ultimately the key driver of rising future network prices. So long as demand continues to decline, no affordable amount of accelerated depreciation will achieve long-term price stability. We continue to encourage an open discussion between consumers, network businesses and governments regarding who should pay for the costs of stranded assets

5 AER, *Regulating gas pipelines under uncertainty information paper*, November 2021, p. 25.

associated with past and future capital investments, and when and how these costs are shared.

We have been challenged by some stakeholders who submitted that accelerated depreciation should not be allowed at all. For example, Justice and Equity Centre (JEC) submitted that:

> we regard use of accelerated depreciation as a measure to mitigate future stranding risk as fundamentally inappropriate and an inherent risk that consumers will pay an unreasonable share of stranding risk mitigation costs.[6]

However, we also recognise the potential stranded asset risk faced by JGN. Making a start on accelerated depreciation is necessary to ensure that JGN is not deterred from making efficient investments required to maintain safe and reliable services for an ageing network in the long-term interest of consumers.

Our decision to allow accelerated depreciation is also consistent with our decision for a declining demand forecast for the 2025–30 period, and lower alternative forecast capex, which does not contain any significant growth capex. We consider that accelerated depreciation and minimising capex are both necessary to reduce stranded asset risk.

Our final decision is to allow a measured start to accelerated depreciation, rather than none. However, any amount of accelerated depreciation must be balanced against price impacts and affordability. There is a real risk that adopting a policy of accelerating depreciation, without clearly defined limits, would be likely to result in large and repeated increases in future gas prices. This would not align with the long-term interests of customers, as it risks the use of the network (including the number of customers) to decline faster than anticipated, which further increases the risk of asset stranding and of costs being borne by an even smaller number of customers in the future. As such, in determining the amount of accelerated depreciation, we have applied a limit on the real price increase as a guardrail.

Our final decision is to not accept JGN's revised proposed accelerated depreciation amount of $230 million, and we have instead determined a reduced amount of $115 million for the 2025–30 period.

Compared to the draft decision, the final decision rate of return is higher, and the final decision expected inflation is lower. These updates have led to higher revenues and result in higher prices for the final decision. Considering this, our final decision applies a higher 'base' real price increase limit of 0.5% compared to the 0.0% determined at the draft decision. Despite this increased limit, our final decision determines a lower total accelerated depreciation amount of $115 million compared to the $156 million at the draft decision, offsetting some of the impact of increased revenues from changes in the rate of return and expected inflation being borne by JGN's customers. The higher rate of return and lower expected inflation alone has led to a $84 million (2.7%) increase in total revenue compared to the draft decision. We reduced the accelerated depreciation amount to limit the further upward pressure on prices from accelerated depreciation.

We consider the reduced accelerated depreciation amount strikes a balance between the need for a start of accelerated depreciation to promote efficient investment, and the need to limit the impact of accelerated depreciation on consumers, particularly at a time when energy

6 JEC, *JGN access arrangement 2025 to 2030 – Submission to AER,* February 2025, p.3.

affordability continues to be a key issue during the energy transition. This reduced amount also reflects the outlook and strength of policy signals surrounding the future role of JGN's gas network in NSW at the present time. We note that unlike Victoria[7] and the ACT[8], there is currently no statewide ban on new gas connections or a gas substitution roadmap in NSW. Even after the publication of a roadmap, there may still be a period of uncertainty regarding the speed of electrification and the materialisation of this impact on gas demand. As such, we consider more accelerated depreciation at this stage is not appropriate given the evolving policy environment in NSW.

Emissions reduction and safe disconnections

Our draft decision supported JGN undertaking tariff reform, to flatten its gas transportation tariff and to better align with the emissions reduction aspect of the NGO. JGN's revised proposal provided additional detail on how it will incrementally deliver this reform over the 2025−30 period, for volume (small) customers. Our final decision is to approve this reform. We also note, and agree with, JGN's proposal to engage its demand (large) customers during the 2025−30 period about reforming its declining block tariff structure in future.

We further support JGN's proposal to incrementally rebalance cost recovery between volume and demand customers, to alleviate residential and small business customers of some cost recovery burden. We consider it appropriate for large commercial and industrial customers to contribute more to JGN's cost recovery, reflecting their proportionally larger use of gas from JGN's network.

On customer disconnections, again, there is a balance to be struck between customers who trigger the necessary works paying the full cost of making their unused connection safe, versus the incentive properties of cost reflective pricing and safety risks associated with unused connections remaining in situ. Consistent with our draft decision, our final decision is to partially socialise across remaining customers the cost of abolishing a connection point, setting an upfront tariff of $250 for customers permanently leaving JGN's network.[9] However, for customers requesting abolishment with the intention of re-connecting, a fully priced abolishment tariff of $1,200.60 will apply.[10]A variable price will be available for customers in multi-tenancy properties, reflecting the more limited works required in most of those contexts. Noting that JGN requires time to work with retailers to establish appropriate systems and protocols to deliver these changes, we require these pricing changes to commence on 1 July 2026.

The energy transition and the tools to address ongoing uncertainty

The energy transition is an ongoing journey and for NSW, the upcoming Gas Decarbonisation Roadmap (the roadmap) will provide an opportunity to have further direction on the role of gas in the future of the energy system. For JGN, developments such as the

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7 The Victorian Government has banned natural gas connections in all new homes that require a planning permit in the state from 1 January 2024. This policy does not apply to existing homes or new homes that do not require a planning permit. Victorian Government: *Victoria's gas substitution roadmap*, September 2023.

8 The ACT Government has banned new gas network connections in certain circumstances since 8 December 2023; ACT Government: *Canberra's Electrification pathway*, accessed on 6 November 2024.

9 This tariff, like all ancillary network service tariffs, will be escalated annually by CPI.

10 To be escalated annually by CPI.

roadmap, or potential opportunities for investment in renewable sources of gas, or significant changes to demand, are all events that may impact it during the 2025–30 period.

The regulatory framework provides a range of tools to manage uncertainty, including cost pass throughs, the speculative capex account, our power to make an advance determination with regarding future capex under NGR rule 80, and our ability to include, in the opening capital base for 2030–35, conforming capex that we did not consider was forecast conforming capex in our 2025–30 decision. JGN's new hybrid tariff variation mechanism is an additional mechanism to manage demand uncertainty, both for JGN and its customers. Gas distributors have a further option to apply to us to reopen their approved access arrangement, should they consider their circumstances warrant it.

As contemplated by our draft decision, our final decision is to approve JGN's proposed hybrid tariff mechanism. This is the first time we have approved a mechanism incorporating elements of both weighted average price cap regulation and revenue cap regulation. We consider it strikes an appropriate balance in assigning some volume risk to JGN and some to its customers. We encourage other gas distributors to consider similar approaches.

As a further acknowledgement of the changing context for its network services, JGN also proposed changes to its Model Standing Offer (MSO) for new small customer connections. Following our approval, JGN can now require more small customers to make an up-front financial contribution to the cost of connecting to its network. While JGN's proposal and our assessment of the new MSO is a separate process to this access arrangement review, the close linkages warrant referencing it here. We note that there remain significant limitations in the new MSO arrangements, in that most new small customers will likely not face any connection charges, reflecting existing impediments to cost reflective connection charges embedded in the NGR. Nonetheless, JGN's initiative is a step in the right direction.

As noted in a recent rule change request from the ECA, the connection charge criteria in the NGR 'limit both the circumstances in which distributors may charge customers for new connections, and the amount they may charge'.[11]

Better resets handbook

As outlined in our draft decision, JGN is the first gas business to participate in our Better Resets Handbook's (the Handbook) early signal pathway.[12] We acknowledge JGN's genuine commitment to this process. In this case, the uncertainty of future of gas demand meant that it was difficult to provide early signals that the expectations in the Handbook had been met.

The expectations in the Handbook provide important guidance for businesses when engaging with their customers, as well as providing our expectations for areas of review such as forecast expenditure and depreciation.[13] While the complexity of the energy transition will make it difficult for businesses to engage with the early signal pathway, these expectations continue to be important considerations in our assessment.

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11 Energy Consumers Australia (ECA), *NGR rule change proposal*, March 2025.

12 AER, *Issues Paper - Jemena Gas Networks (NSW) – 2025–30 Access Arrangement*, August 2024, p. 7.

13 AER, *Better Resets Handbook,* December 2021.

Contents

1 Our final decision

Jemena Gas Networks' (JGN) (NSW) proposed access arrangement sets out the services it will provide in the 5 years from 1 July 2025 to 30 June 2030 (2025–30 period), the tariffs for those services, and the other terms and conditions on which they will be provided.

An access arrangement final decision is a decision to approve, or to refuse to approve, an access arrangement proposal.[14] If, in an access arrangement final decision, we refuse to approve an access arrangement proposal, we must propose an access arrangement or revisions to the access arrangement (as the case requires) for the relevant pipeline.[15] Because we have not approved JGN's revised proposal, our final decision is accompanied by a revised access arrangement and tariff schedule.

At the centre of our decision is the forecast total revenue requirement for the provision of the regulated haulage reference service over the next 5 years. Our final decision includes total revenue of $3,106.7 million ($ nominal, smoothed) compared to JGN's revised proposal of $3,246.4 million. This is a reduction of $139.7 million (4.3%) from JGN's revised proposal.

1.1 What is driving revenue?

Over time, inflation impacts the spending power of money. To compare revenue from one period to the next on a like-for-like basis, in this section we use 'real' values based on a common year (2024–25) that have been adjusted for the impact of inflation instead of the nominal values above.

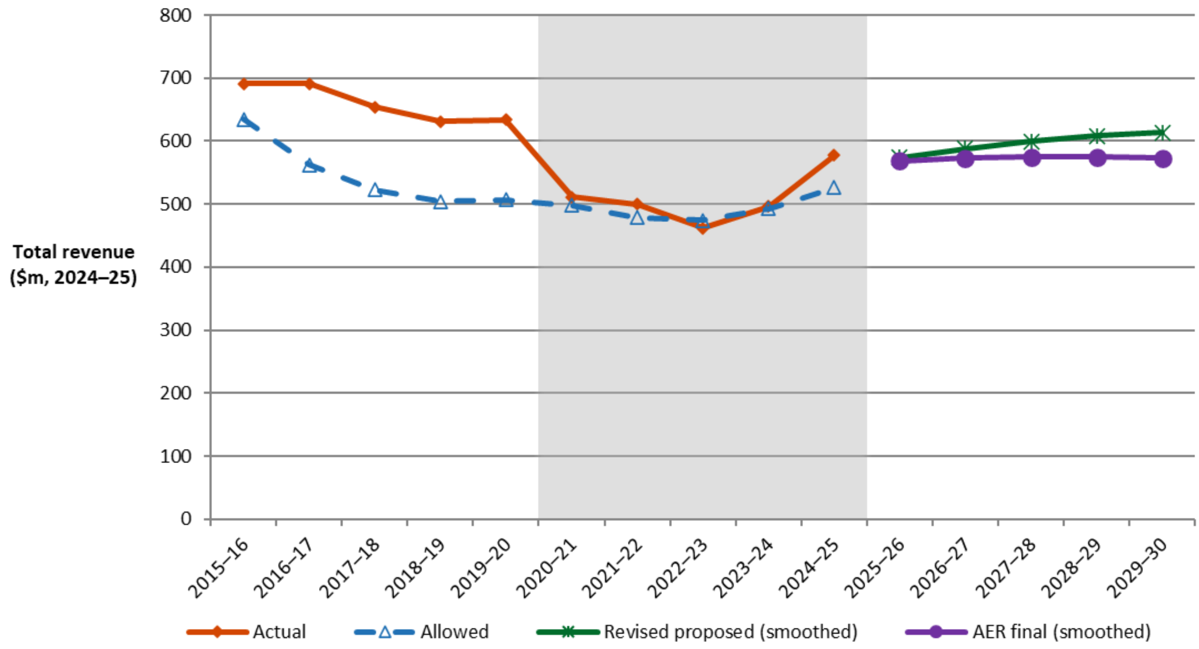
Where the assumptions in JGN's revised proposal would have resulted in total smoothed real revenue that was $513.4 million (20.8%) higher than approved for the current period, the modelled impact of our final decision is an increase of $394.2 million (16.0%).

Figure 1 shows how real revenue would change over the next 5 years under this final decision, compared to JGN's revised proposal.

14 NGR, r. 62(2).

15 NGR, r. 64(1).

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



Source: AER analysis.

There are several reasons for this increase in revenue. Figure 2 highlights the key drivers of the change between the expected real revenue approved for JGN's 2020–25 period and that approved in this final decision for the 2025–30 period. It shows that our final decision provides for increases in the building blocks for:

- return on capital, which is based on the opening capital base, forecast capex and rate of return. This is $261.7 million (29.8%) higher than the 2020–25 period. As shown in Figure 3, JGN's capital base is projected to decline in real terms over the 2025–30 period. Forecast capex is lower than in previous periods as the amount of capex required to meet growth in demand and new customer connections declines. Also contributing to the declining capital base is the measured start to accelerated depreciation of assets under this final decision, which increases the rate at which assets are 'removed' from the capital base. However, the rate of return over the 2025–30 period is higher than the 2020–25 period, offsetting what would otherwise be a downward impact on the return on capital building block.
- cost of corporate income tax, which is $54.1 million higher than the 2020–25 period, primarily due to a higher return on equity and a lower tax depreciation in the 2025–30 period compared to the 2020–25 period.[16]
- revenue adjustments, which are $254.5 million higher than the 2020–25 period, mainly due to the expiry of a one-off large negative revenue adjustment for the 2015–20 remittal decision included in the 2020–25 access arrangement.[17] To a lesser extent, it is also

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16 Return on equity is a component of revenue for tax purposes and tax depreciation is a component of tax expense. All else equal, a higher return on equity and lower tax depreciation means a higher taxable income and therefore a higher cost of corporate income tax amount.

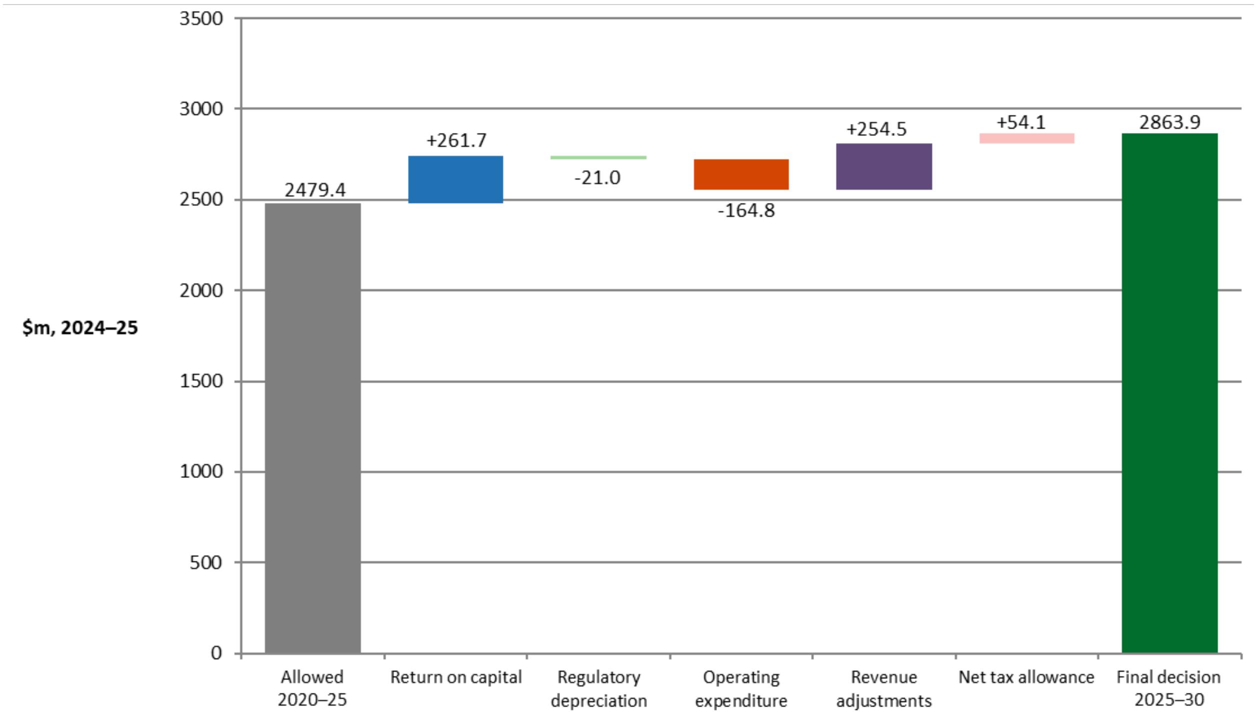
17 See AER, *Final decision - JGN access arrangement 2020–25 – Overview,* June 2020, p. 13.

driven by a higher carryover amount resulting from the opex Efficiency Carryover Mechanism (ECM), and a positive revenue adjustment resulting from the introduction of the Capital Expenditure Sharing Scheme (CESS).

Figure 2 also shows that our final decision provides for decrease in the building blocks for:

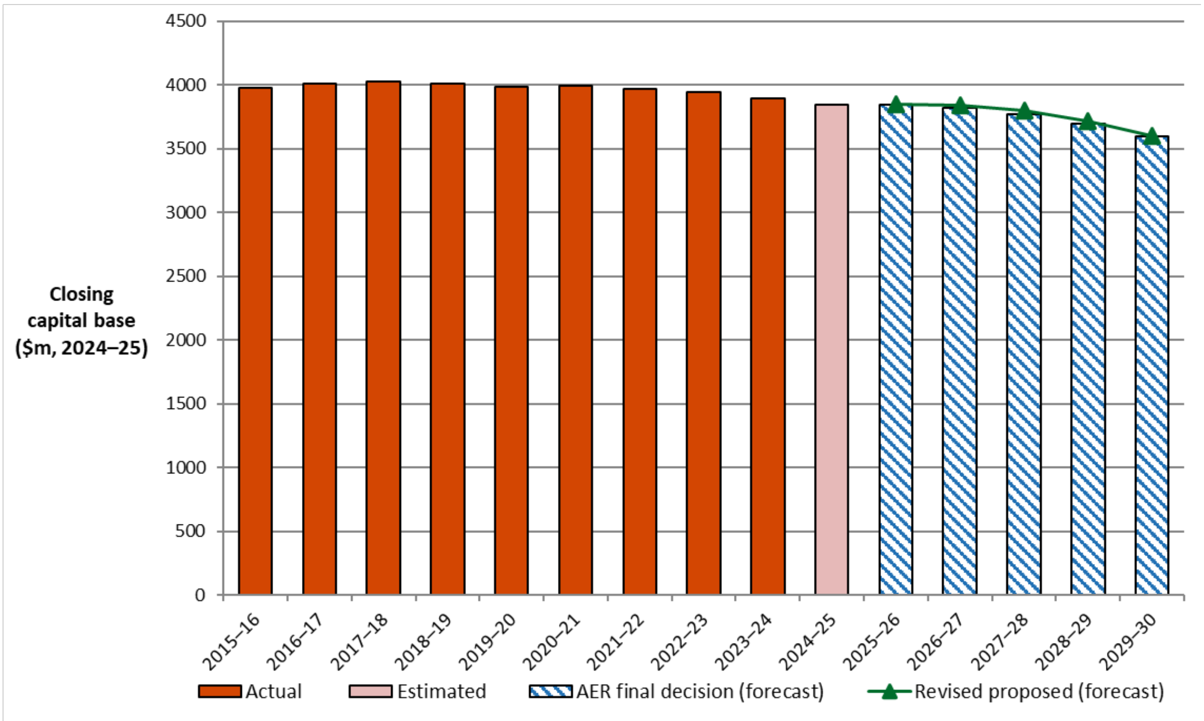
- return of capital (regulatory depreciation), which is $21.0 million (4.2%) lower than the 2020–25 period. This is primarily driven by the higher indexation of the capital base reflecting higher expected inflation rate for the 2025–30 period. This is also driven by lower straight-line depreciation associated with new capex reflecting a lower capex forecast for the 2025–30 period. Combined, this more than offsets the impact of the higher straight-line depreciation due to applying accelerated depreciation for the 2025–30 period.
- forecast opex for the 2025–30 period is $164.8 million (12.6%) lower than allowed in the determination for the 2020–25 period. The decrease in the forecast period is due to the removal of ancillary reference service costs from the opex forecast for the 2025–30 period and lower unaccounted for gas costs.

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



Source: AER analysis.
Note: Allowed revenue and proposed revenue in the chart are unsmoothed total revenue for the access arrangement period. The 2020–25 allowed revenues (including opex) are converted to real 2024–25 dollars using lagged consumer price index (CPI). The higher revenue adjustments are mainly due to the expiry of a one-off large negative revenue adjustment of $203.9 million for the 2015–20 remittal decision included in the 2020–25 access arrangement decision.

Figure 3 JGN's capital base value over time ($ million, 2024–25)



Source: AER analysis.

1.2 Key differences between this final decision and JGN's revised proposal

In real terms, this final decision allows JGN to recover a total building block revenue of $2,863.9 ($2024–25, unsmoothed) over the 2025–30 period. We have made amendments to core components of JGN's proposal which have led to a lower revenue outcome. For the 2025–30 period, the main areas of difference between our final decision and JGN's revised proposal include:

- Reducing forecast capex by $120.7 million ($2024–25)[18], primarily driven by reduction to JGN's meter replacement, other capex (which includes obsolescence expenditure), an adjustment to JGN's proposed scope factor allowance for capex projects, and not accepting the renewable connections proposal.
- Reducing accelerated depreciation by $115 million ($2024–25). While we allow a measured start of accelerated depreciation of JGN's existing pipeline assets, we do not accept the full $230 million proposed by JGN in its revised proposal.
- Our reduced opex forecast, primarily driven by a reduction to forecast costs for socialised small customer connection abolishment by $3.6 million ($2024–25).

Movements in market variables have also led to the different revenue outcome in our final decision compared with JGN's revised proposal, all else being equal. These include:

18 These figures are net of capital contributions, but inclusive of asset disposals.

- Our updated calculation of JGN's rate of return, which increased to 6.17% from JGN's placeholder estimate of 6.11%.[19] This resulted in a higher return on capital amount of $1,236.4 million ($ nominal) determined in this final decision compared with JGN's revised proposal of $1,231.0 million.
- Lower expected inflation, based on the Reserve Bank of Australia's (RBA) February 2025 Statement on Monetary Policy (2.72% per annum compared with 2.80% in JGN's revised proposal), has slightly increased the regulatory depreciation amount relative to JGN's revised proposal.

These updates in market variables are a standard part of our decision-making process and do not reflect areas of difference between us and JGN.

1.3 Expected impact of our final decision on tariffs and gas bills

We combine our forecast revenue requirement for JGN with forecast demand to determine its network tariffs. The forecast demand in this final decision is declining. In simple terms, tariffs are determined by dividing cost (total revenue requirement) by total demand. This means that for the same revenue amount, a decrease in forecast demand leads to an increase in tariffs.

The combined effect of rising revenue and declining demand over the 2025–30 period is that this final decision will increase JGN's tariffs relative to the current period. For illustrative purposes only, we estimate the modelled impact of this final decision would be a total increase to average tariffs of around 20.1% in nominal terms by 2029–30 compared to 2024–25 levels, or an average nominal increase of 3.7% per annum.[20]

Figure 4 shows the indicative tariff paths for JGN's gas transportation reference services across the 2025–30 period. It compares the tariff path under this final decision with that approved previously for the 2020–25 period, and with JGN's revised proposal. These are simple estimates only, calculated based on an aggregate level rather than individual zone level tariffs. While our decision establishes tariffs for year 1 (2025–26) directly, tariffs for years 2 to 5 will be set as part of the annual reference tariff variation mechanism reflecting actual inflation, updated return on debt and any cost pass throughs.[21]

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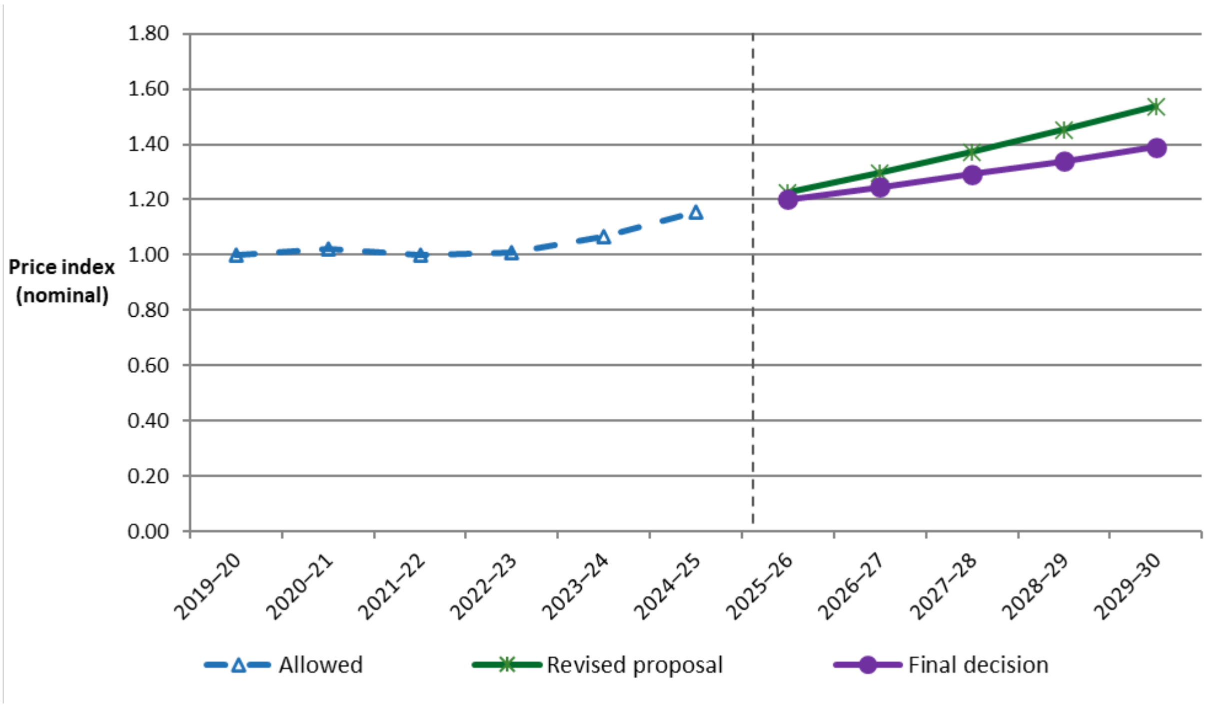
19 Average nominal vanilla WACC over the 2025–30 period.

20 In real ($2024–25) terms, the impact of this final decision on JGN's tariffs is an increase of around 3.7% by the end of the 2025–30 period, or an average real increase of 1.0% per annum.

21 The reference tariff variation mechanism is discussed in section 5.2 of this paper and in Attachment 10 of this final decision.

Figure 4 Indicative reference tariffs paths for JGN's reference services from 2025 to 2030 (Price index, nominal)



Source: AER analysis.

1.3.1 Potential bill impact

JGN's network charges make up around 39.6% of its residential customers' gas bills and 20.2% of its small business customers' gas bills. Other components of the gas supply chain—the cost of purchasing gas from the wholesale market, transmission network charges, and the costs and margins applied by gas retailers in determining the prices they will charge consumers for supply—also contribute to the prices ultimately paid by consumers. These sit outside the decision we are making here but will also continue to change throughout the period.

In nominal terms, which include the impact of expected inflation, this final decision would lead to an increase in the distribution component of gas bills for JGN's customers. We estimate that the modelled impact of our final decision on the average annual gas bill, as it is today, would be:[22]

- a nominal increase of $61 (8.0%) by 2029–30, or an average of $12 (1.5%) per annum for a residential customer
- a nominal increase of $634 (4.1%) by 2029–30, or an average of $127 (0.8%) per annum for a small business customer.

[22] Our estimated bill impact is based on the typical annual gas usage of 15 GJ and 500 GJ for residential and small business customers in JGN's network area, respectively, with a base bill of $771 for residential customers and $15,593 for small business customers as at 2024-25, based on data provided by JGN, *RIN – Att 15 – Workbook 5 – Bill Impacts*, June 2025.

1.4 JGN's consumer engagement

Our draft decision set out the extensive work that JGN undertook to establish its customer engagement program to support the development of its proposal.[23]

In its revised proposal, JGN acknowledged the feedback that it heard from us and stakeholders through our issues paper and draft decision, particularly in relation to its engagement on accelerated depreciation.[24] For example, it noted that the Consumer Challenge Panel, sub-panel 31 (CCP31) 'considered that this topic required further engagement, particularly with residential and small business customers and that such engagement should validate customers' understanding of what they are being asked.'[25]

JGN's Advisory Board agreed that further customer engagement should focus on accelerated depreciation. The Advisory Board noted:

> that this engagement should be quantitative in nature, for example a quantitative survey, to triangulate feedback from our Customer Forum and validated by the Sagacity and JG Insights Research.[26]

In response, JGN engaged Sagacity and JD Insights to conduct an online quantitative survey to understand customer preferences on accelerated depreciation:[27] They undertook two stages of research:

1. Cognitive testing: 8 iterative online in-depth interviews conducted with customers to gauge their understanding of accelerated depreciation, using informational videos and survey questions.
2. Online survey: conducted with 1,006 customers, with an effort to reflect JGN's customer base. JGN interviewed customers taking into account gender, age, geography, and language spoken at home.[28]

JGN submitted that the research sought to understand how well customers understood the topic of accelerated depreciation. Sagacity and JD Insights noted that, after watching the video, 71% stated they understood the topic 'extremely' or 'very' well. These results were similar amongst those who also spoke a language other than English (72%) and those without a degree (67%).

The survey presented customer bill impacts with 4 options, each with varying degrees of accelerated depreciation starting from a low amount of $100 million and up to an amount of $400 million. This information was presented to the customers in terms of the impact it would have on their bill. Customers were asked to rank these options in order of their preference.[29]

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23 AER, *Draft decision - JGN access arrangement 2025–30 – Overview,* December 2025, p. 6-10.

24 JGN, *Revised 2025 Plan,* January 2025, p. 7.

25 JGN, *Revised 2025 Plan,* January 2025, p. 7.

26 JGN, *KPMG - RP - Att 2.2 - Advisory Board - Detailed Record,* January 2025, p. 5.

27 JGN, *Revised 2025 Plan,* January 2025, p. 8.

28 JGN, *Sagacity - RP - Att 2.1 - Accelerated Depreciation Research Report,* December 2025, p. 5; JGN, *Revised 2025 Plan,* January 2025, pp. vi, 8.

29 JGN, *Sagacity - RP - Att 2.1 - Accelerated Depreciation Research Report,* December 2025, p. 9.

JGN indicated that the results from the survey reaffirmed the feedback that it had heard throughout its customer engagement:

> Over 70% of customers surveyed ranked the two highest price levels of accelerated depreciation—which correspond to $400 million and $300 million over the 2025–30 period—as their first preference, recognising the trade-off between short versus long-term bill impacts and the impacts on customers unable to transition away from the gas network.[30]

CCP31 commended JGN for acting on the recommendation from its Advisory Board to gather quantitative evidence of customer support for its proposal.[31] However, CCP31 still retained concerns about the survey evidence used to support JGN's accelerated depreciation proposal.

CCP31 commented specifically on the survey scope, methodology and interpretation of the results. It noted that educated and relatively affluent customers are overrepresented in the sample relative to JGN's customer base, constituting sample bias towards people with greater capacity to pay higher bills.

In contrast, CCP31 considered low-income households, including renters, would likely opt for lower rates of accelerated depreciation. CCP31 confirmed with JGN that this overrepresentation of higher income customers was not accounted for during the sample size weighting process.[32]

JEC and Energy Consumers Australia also noted concerns about engagement undertaken on accelerated depreciation.[33] JEC acknowledged the difficulty in engaging between proposals, however noted that consumer stakeholders (including JGN's customer panel, which JEC is a member of) had little to no input in the design, development or assessment of the content and findings of this survey.[34] JEC submitted:

> We do not consider JGN's follow-up survey sufficiently robust and recommend its results be discounted in their contribution to any assessment of the validity of consumer preferences in relation to accelerated depreciation. Given the materiality of the decision and its long-term impacts on consumers, we consider it reasonable and appropriate to set a high bar for the level of engagement required to demonstrate proposals are well grounded in consumer preferences.[35]

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30 JGN, *Revised 2025 Plan,* January 2025, p. vi.

31 CCP31, *Advice to the AER - JGN 2025–30 revised access arrangement and draft decision,* February 2025, p. 15.

32 CCP31, *Advice to the AER - JGN 2025–30 revised access arrangement and draft decision,* February 2025, p. 15.

33 See ECA, *Submission on JGN's 2025–30 revised proposal and draft decision*, February 2025, p. 6; JEC, *Submission on JGN's 2025–30 revised proposal and draft decision*, February 2025.

34 JEC, *Submission on JGN's 2025–30 revised proposal and draft decision*, February 2025, p. 6.

35 JEC, *Submission on JGN's 2025–30 revised proposal and draft decision*, February 2025, p. 6.

Our conclusions on JGN's consumer engagement

The energy transition is creating challenges that require gas networks to think about how key components of an access arrangement proposal may impact customers now and in the future. We acknowledge the challenges of communicating to consumers the complex topic of accelerated depreciation and stranded asset risk to achieve meaningful engagement. Overall, we consider JGN has shown genuine commitment to listening to its customers through its willingness to continue to engage on complex issues.

It is important that customers understand the interconnected nature of the different components of the gas network's proposal and the short-term and long-term impact of those key components. For example, how new capex investments, or increased accelerated depreciation may impact or benefit customers now and in the future during the energy transition. It is only through understanding all options that consumers can fully make an informed decision.

While JGN at a high level invested heavily in its consumer engagement activities, on topics such as renewable gas connections and accelerated depreciation, we consider JGN could have provided more detailed context or broader range of options to consumers to fully inform their views. In this respect our views align with views expressed by CCP31 and JEC, that JGN could have done more to help surveyed consumers understand the full breadth of the issues and potential approaches going forward.

The extent to which stakeholder submissions were influenced by JGN's engagement is unclear. Stakeholder submissions generally expressed that JGN's proposal for accelerated depreciation should be rejected, citing a lack of adequate information provided to consumers to enable informed decision-making, and submitting that JGN's proposal is not aligned with the long-term interests of consumers. However, views expressed in submissions on renewable gas connections were mixed. Some stakeholder submissions outright opposed JGN's renewable gas connection proposal.[36] In contrast, we received a number of submissions from renewable gas proponents and large commercial customers who offered strong support for JGN's proposed renewable gas connections.[37]

As noted above, we acknowledge the inherent complexity of communicating issues such as new capital investment, accelerated depreciation and stranded asset risk. However, it remains critical that consumers are provided with a clear understanding of how these elements—alongside capital investment and demand forecasts—interact to shape pricing outcomes.

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36 City of Sydney, *AER draft decision – JGN access arrangement 2025–30*, February 2025; Energy Consumers Australia, *JGN access arrangement 2025 to 2030 – Submission to AER*, February 2025.

37 Optimal Renewable Gas, *Submission and attachment on JGN's 2025–30 revised proposal and draft* decision, January 2025; Opal, *Submission on JGN's 2025–30 revised proposal and draft decision*, February 2025; Sojitz, *Submission on JGN's 2025–30 revised proposal and draft decision*, February 2025; Gwydir, *Submission on JGN's 2025–30 revised proposal and draft decision*, February 2025; Australian Pipelines and Gas Association, *Submission on JGN's 2025–30 revised proposal and draft decision*, February 2025; A2EP, *Submission on JGN's 2025–30 revised proposal and draft decision*, February 2025; Bioenergy, *Submission on JGN's 2025–30 revised proposal and draft decision*, February 2025; GreenPower, *Submission on JGN's 2025–30 revised proposal and draft decision*, February 2025.

In Attachment 4 to this final decision, we provide additional guidance around our engagement expectations on the topic of accelerated depreciation and stranded asset risk for the network businesses to consider when engaging with their customers and stakeholders for future access arrangement reviews.

While we maintain our overall positive view of JGN’s consumer engagement, including its commendable tariff engagement, we note some areas of further improvement on critical issues with large revenue impacts. On those issues, we consider a more fulsome explanation of options, and of the pros and cons of JGN’s proposals, would have been beneficial for its customers.

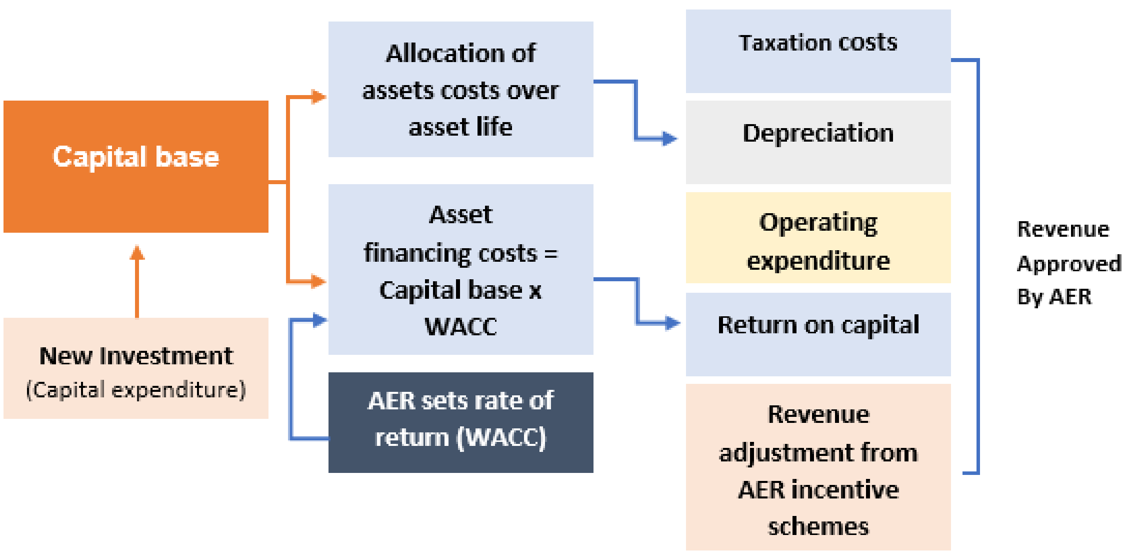
2 Total revenue requirements

The foundation of our regulatory approach is a benchmark incentive framework to setting revenues: once regulated revenues are set for the 5-year period, a network that keeps its actual costs below the regulatory forecast of costs retains part of the benefit. Service providers have an incentive to become more efficient over time, as they retain part of the financial benefit from improved efficiency. Consumers also benefit when efficient costs are revealed, and a lower cost benchmark is set in subsequent access arrangement periods.

JGN's proposed revenue requirement, and our assessment of it under the NGL and NGR, is based on six cost components or building blocks, illustrated in Figure 5:

- return on the capital base – to compensate investors for the opportunity cost of funds invested in this business
- depreciation of the capital base – or return of capital, to return the initial investment to investors over time
- capex – the capital costs and expenditure incurred in the provision of network services, which directly affects the size of the capital base and, therefore, the revenue generated from the return on capital and depreciation building blocks
- 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 ECM and CESS
- estimated cost of corporate income tax.

Figure 5 The building block approach to determining total revenue



Source: AER.

2.1 Final decision on total revenue

The total revenue requirement is a forecast of the efficient cost of providing gas distribution services over the access arrangement period. We determine annual revenue, and the total revenue requirement, in nominal terms that take expected future inflation into account. We use 5-year inflation expectations to convert revenues to nominal values.

Our final decision on JGN's total revenue requirement is $3,106.7 million ($ nominal, smoothed). This is a reduction of $139.7 million (4.3%) from JGN's revised proposal.

Table 1 sets out our final decision on JGN's total revenue requirement (by building block) for each year of the 2025–30 period, the total revenue after equalisation (smoothing), and the X factors that we have determined for use in the tariff variation mechanism.

Table 1 AER's final decision on JGN's smoothed total revenue and X factors for the 2025–30 period ($ million, nominal)

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
Return on capital	233.1	240.7	247.9	254.8	259.9	1,236.4
Regulatory depreciation	84.3	93.3	103.4	113.4	123.9	518.4
Operating expenditure	239.7	240.5	246.3	251.7	263.4	1,241.6
Revenue adjustments	37.5	5.0	–16.4	6.3	7.7	40.0
Net tax allowance	11.6	12.6	13.8	15.2	17.0	70.3
Total revenue - unsmoothed	606.1	592.1	595.1	641.4	671.8	3,106.6
Forecast revenue – smoothed	**583.6**	**604.9**	**622.7**	**640.3**	**655.2**	**3,106.7**
X factors[a]	—0.99%	–0.98%	–0.98%	–0.98%	–0.98%	n/a

Source: AER analysis.
n/a: not applicable.
(a) Under the CPI–X form of control, a negative X factor is an increase in price (and therefore, in revenue). The X factor for 2025–26 is indicative only. Our decision establishes 2025–26 tariffs directly, rather than referencing a change from tariffs for 2024–25. The X factors for 2026–27 to 2029–30 will be revised to reflect the annual return on debt update.

2.2 Revenue smoothing and tariffs

JGN currently operates under a weighted average price cap as its tariff variation mechanism. Our final decision approves a hybrid mechanism, incorporating elements of both weighted average price cap regulation and revenue cap regulation, for the 2025−30 period.

The hybrid mechanism does not change how we determine JGN's gas transportation tariffs ahead of the 2025−30 period. The revenue cap elements of the hybrid mechanism will apply during the period, to partially true-up revenues in the event that actual volumes significantly diverge from forecasts used to derive JGN's gas transportation tariffs. Ahead of the period beginning, our approach to set tariffs is unchanged from our approach under JGN's existing weighted average price cap.

This means we must determine the weighted average tariff change each year such that the net present value (NPV) of unsmoothed and smoothed revenue is equal across the 2025–30 period. This average tariff change is known as the 'X factor'.

Our final decision on JGN's access arrangement proposal includes a determination of JGN's total building block revenue (unsmoothed revenue), and a smoothed revenue profile across the 2025–30 period.

The X factors represent the weighted average real change in tariffs. As part of the annual reference tariff variation process applying from 2026–27, we combine the X factors we have determined in our decision with actual inflation to create nominal reference tariffs for the coming year. This means that the prices paid by consumers, and therefore the revenues received, change with actual inflation, plus the annual X factor rate.

By smoothing the revenues, we aim to minimise price volatility between and within access arrangement periods by keeping the difference between smoothed and unsmoothed revenue in the final year of each period as close as possible, and to provide price signals across tariffs that reflect JGN's underlying, efficient costs of providing services. Our standard approach has been to keep a divergence of up to +/–3% between the smoothed and unsmoothed revenues for the last year of the period if this can achieve smoother price changes across the access arrangement periods.

In this final decision, we approve lower revenues than JGN's revised proposal. This is mainly driven by our reduction to JGN's revised proposed accelerated depreciation. However, our final decision allows for higher revenues than those determined in the 2020–25 period. The rising revenues and declining demand mean that prices are increasing over the 2025–30 period.

We have smoothed the increase in forecast revenues to achieve a more stable price path for the 2025–30 period. We have maintained our standard approach to the final year difference between the smoothed and unsmoothed revenues. In the present circumstances, we have determined that the final year revenue difference is about –2.5%. We are satisfied that the final decision tariff path effectively balances the aims of price path stability within the 2025–30 period and across periods.

The average annual tariffs in year 1 (2025–26) determined in our final decision are 2.1% lower in nominal terms than JGN's revised proposal. While our decision establishes tariffs for year 1 (2025–26) directly, tariffs for years 2 to 5 will be set as part of the annual reference tariff variation mechanism reflecting actual inflation, updated return on debt and any cost pass throughs.[38]

[38] The annual reference tariff variation mechanism is discussed in Attachment 10.

3 Key elements of our final decision on revenue

The components of our final decision include the building blocks we use to determine the total revenue requirement. The following sections summarise our revenue decision by building block. Where relevant, attachments to this final decision provide a more detailed explanation of our analysis and findings.

3.1 Capital base

The capital base accounts for the value of regulated assets over time. To set revenue for a new access arrangement period, we take the opening value of the capital base 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 capital base at the end of each year of the access arrangement period. The value of the capital base is used to determine the return on capital and depreciation building blocks.

In this final decision, we determine an opening capital base value of $3,846.7 million ($ nominal) as at 1 July 2025 for JGN. This value is $6.4 million (0.2%) lower than JGN's proposed opening capital base of $3,853.1 million ($ nominal) as at 1 July 2025.[39] This reduction is due to the update we made to the consumer price index (CPI) input for 2024–25 to reflect the actual outcome in the roll forward model (RFM).[40] For our final decision, we adopt actual CPI value of 2.42% for 2024–25, compared to JGN's revised proposed of 2.60%.

Figure 6 shows the key drivers ($ nominal) of the change in JGN's capital base over the 2020–25 period under this final decision compared to its revised proposal

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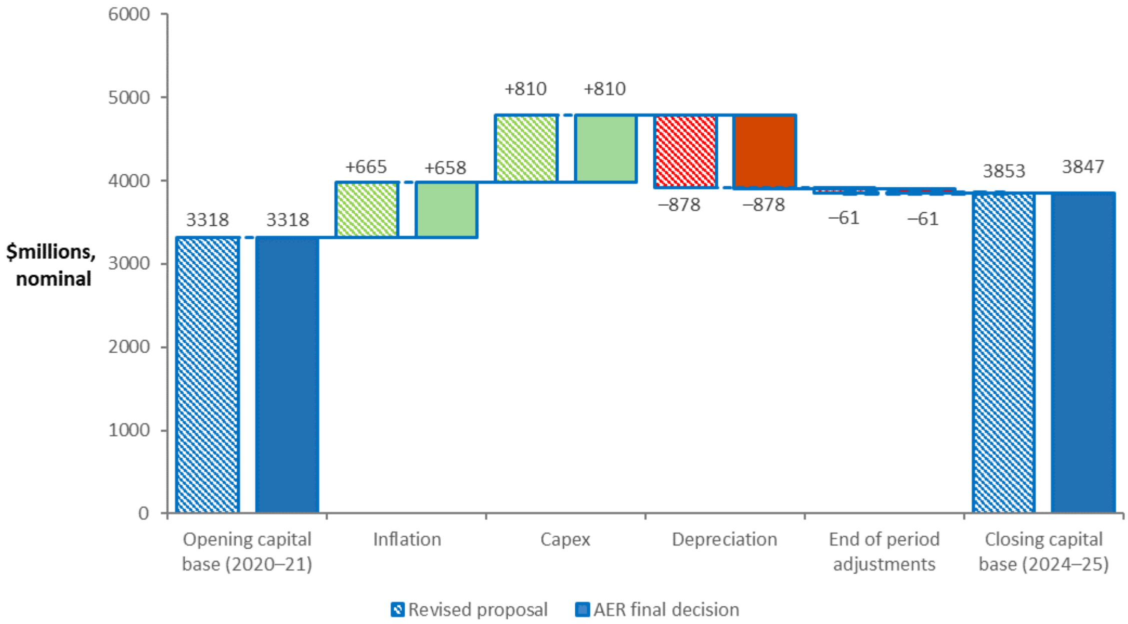
39 JGN, *2025 access arrangement revised proposal Plan, attachment JGN - RP - Att 7.6M - Roll Forward Model*, 15 January 2025.

40 Australian Bureau of Statistics (ABS), *All groups CPI December 2024,* released 29 January 2025.

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



Source: AER analysis.

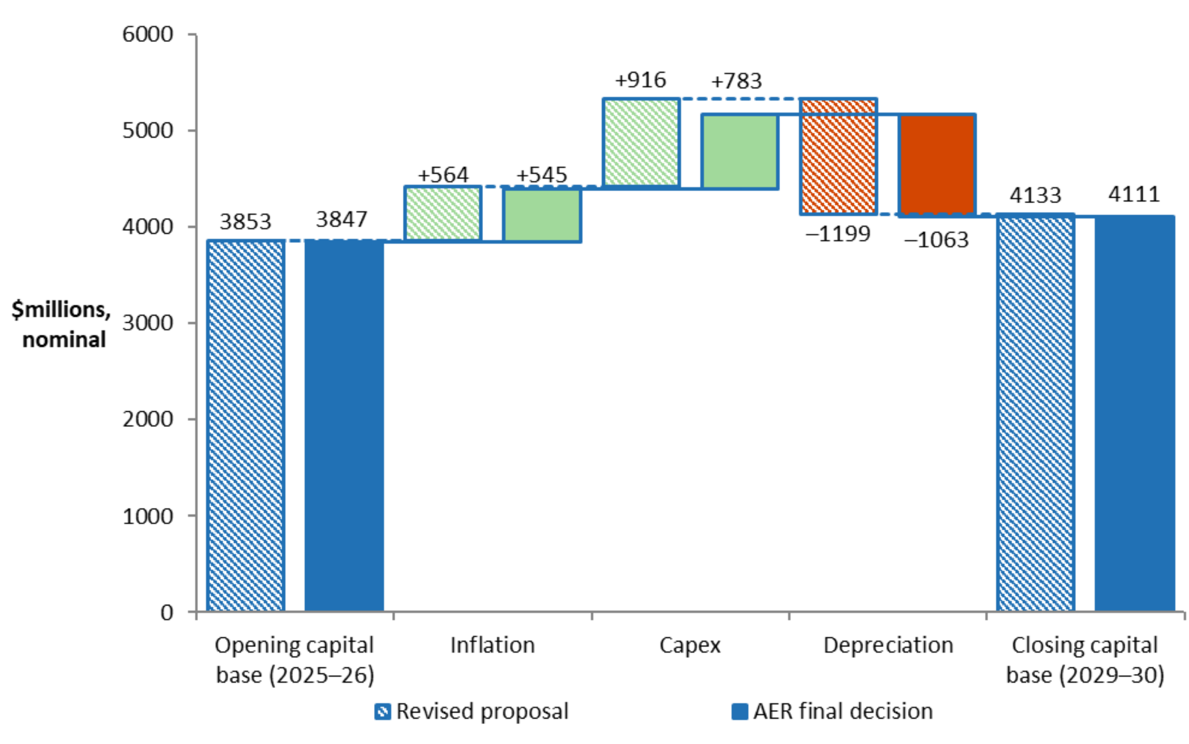
Note: Capex is net of disposals and capital contributions. It is inclusive of the half-year weighted average cost of capital (WACC) to account for the timing assumptions in the RFM.

Figure 7 likewise shows the key drivers ($ nominal) of the change in JGN's forecast capital base over the 2025–30 period in its proposal compared to our final decision. Our final decision projects an increase of $264.3 million (6.9%) to the capital base by the end of the 2025–30 period compared to the $280.3 million (7.3%) increase in JGN's revised proposal.

We determine a projected closing capital base of $4,111.1 million ($ nominal) as at 30 June 2030, which is $22.4 million (0.5%) lower than JGN's proposed $4,133.5 million. This lower value is mainly due to our final decision on a lower forecast capex (discussed in Attachment 5). It also reflects our final decision on the opening capital base as at 1 July 2025, forecast depreciation and expected inflation (discussed in sections 3.3 and 3.2).

The reasons for our decision on JGN's capital base are discussed in Attachment 2.

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



Source: AER analysis.

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

3.2 Rate of return and value of imputation credits

Our 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.[41]

The return each business is to receive on its capital base, 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 capital base.

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

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

We are required by national energy laws and rules to apply the RORI to estimate an allowed rate of return. For this final decision, we have applied the 2022 RORI.[42]

JGN's revised proposal adopted the 2022 RORI.[43] The 6.06% (nominal vanilla) rate of return in this final decision is lower than the 6.09% placeholder in the revised proposal, principally due to a decrease in interest rates.

Our calculated rate of return in Table 2 applies to the first regulatory year of the 2025–30 period. A different rate of return may apply for the remaining years of the period. This is because we will update the return on debt component of the rate of return each year, in accordance with the 2022 RORI, to use a 10-year trailing average portfolio return on debt that is rolled-forward each year. Hence, only 10% of the return on debt is calculated from the most recent averaging period, with 90% from prior periods.

In this final decision, we accept JGN's proposed risk free rate[44] and debt averaging periods[45] because they are consistent with the 2022 RORI.[46] We have also adopted the confidential appendix that we previously issued with our draft decision which sets out the averaging periods.

Table 2 Final decision on JGN's rate of return (nominal)

	AER's draft decision (2025–30)	JGN's revised proposal (2025–30)	AER's final decision (2025–30)	Allowed return over the regulatory control period
Nominal risk-free rate	3.95%	4.56%	4.48%[a]	
Market risk premium	6.20%	6.20%	6.20%	
Equity beta	0.6	0.6	0.6	
Return on equity (nominal post-tax)	7.67%	8.28%	8.20%	Constant (%)
Return on debt (nominal pre-tax)	4.58%	4.63%	4.63%[b]	Updated annually
Gearing	60%	60%	60%	Constant (60%)
Nominal vanilla WACC	5.81%	6.09%	6.06%[c]	Updated annually for return on debt
Expected inflation	2.85%	2.80%	2.72%	Constant (%)

Source: AER analysis; AER, *Draft Decision Attachment 3 - Rate of return - JGN – 2025–30 Distribution revenue proposal*, November 2024, p. 2; JGN, *RP - Att 7.9M - Rate of return model*, January 2025.

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

43 JGN, *Revised 2025 Plan*, January 2025, p. 46.

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

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

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

(a) Calculated using JGN's risk-free rate averaging period of 41 business days from 1 November 2024 to 31 December 2024.
(b) Calculated using JGN's actual nominated return on debt averaging period.
(c) Applied to the first year of the 2025–30 regulatory control period.

Debt and equity raising costs

In addition to compensating for the required rate of return on debt and equity, we provide an allowance for the transaction costs associated with raising debt and equity. We include debt raising costs in the opex forecast because these are regular and ongoing costs which are likely to be incurred each time service providers refinance their debt. On the other hand, we include equity raising costs in the capex forecast because these costs are incurred once and would be associated with funding the particular capital investments. Our approach to forecasting debt and equity raising costs is set out in more detail in our draft decision.[47] JGN has proposed to use our approach to estimate debt and equity raising costs.[48]

Our final decision is to apply a debt raising cost of 8.50 basis points per annum, which has been used to calculate the debt raising cost forecast set out in the opex attachment (Attachment 6).

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

Imputation credits

Our final decision is to apply a value of imputation credits (gamma) of 0.57, as set out in the 2022 RORI.[49] JGN's revised proposal also adopted this value.[50]

Expected inflation

As set out in Table 3, our estimate of expected inflation is 2.72%. It is an estimate of the average annual rate of inflation expected over a five-year period based on the outcome of our 2020 inflation review.[51] JGN's revised proposal also adopted our approach.[52]

Table 3 Final decision on JGN's forecast inflation (%)

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

Source: AER Analysis; RBA, *Statement on Monetary Policy*, February 2025, Table 3.1: Detailed Forecast Table.

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

48 JGN, *RP - Att 7.4M - PTRM - Step 1,* January 2025.

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

50 JGN, *Revised 2025 Plan*, January 2025, p. 47.

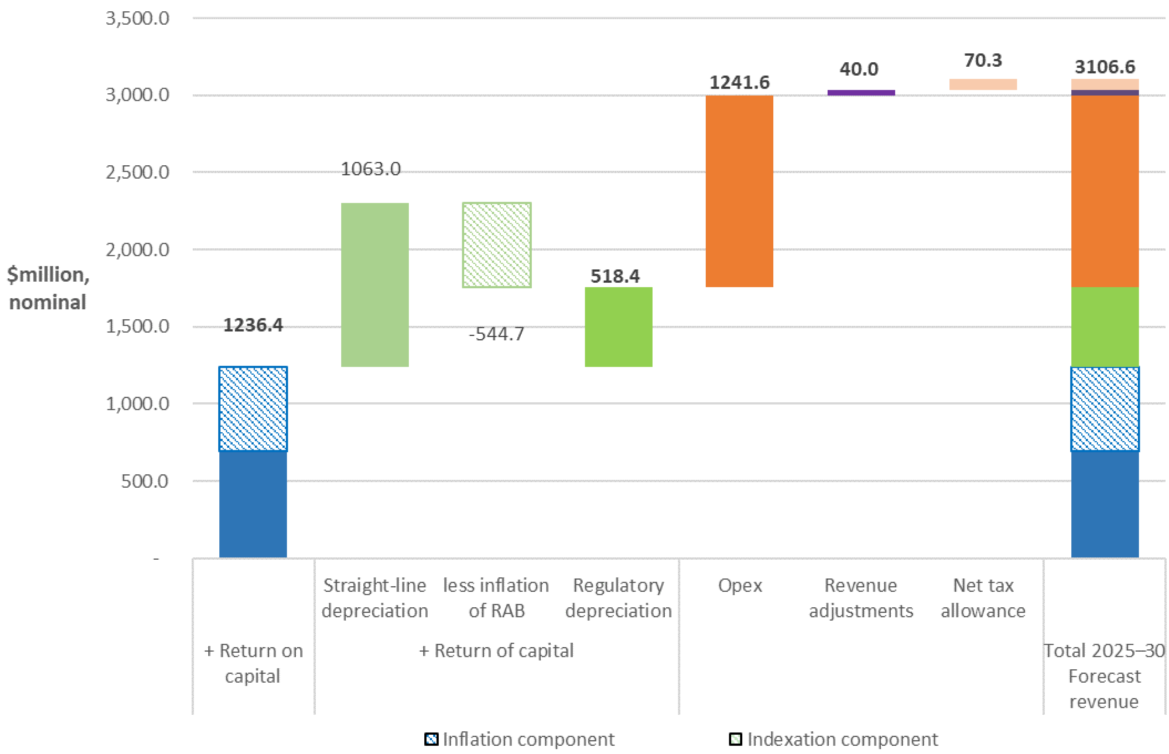
51 AER, *Final position, Regulatory treatment of inflation*, December 2020.

52 JGN, *RP - Att 7.4M - PTRM - Step 1,* January 2025.

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

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

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



Source: AER analysis.

3.3 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 the total revenue for JGN, we include an amount for the depreciation of the projected capital base.[53] Under the building block framework, regulatory depreciation consists of the net total of the straight-line depreciation less the indexation of the capital base.

Our final decision includes a regulatory depreciation amount of $518.4 million ($ nominal). This is $117.0 million (18.4%) lower than from JGN's revised proposed $635.4 million ($

53 NGR, r. 76(b).

nominal). This reduction is primarily due to our final decision to approve a lower accelerated depreciation amount.

It is also driven by our final decision on other components of JGN's proposal which further contributed to the reduction to the regulatory depreciation amount. These amendments include a lower opening capital base at 1 July 2025 and a lower forecast capex.

3.3.1 Accelerated depreciation due to stranded asset risk

Consistent with our draft decision, our final decision applies a measured start to accelerated depreciation for reducing stranded asset risk associated with long term demand uncertainty. However, we do not accept JGN's revised proposed accelerated depreciation amount of $230 million ($2024-25), and instead determine a reduced amount of $115 million ($2024-25) for the 2025–30 period.

We have been challenged by some stakeholders submitting that accelerated depreciation should not be allowed at all. Despite this, our final decision is to allow a measured start to accelerated depreciation, rather than none, in recognition of the potential stranded asset risk faced by JGN. This is necessary to ensure that JGN is not deterred from making efficient investments required to maintain safe and reliable services for an aging network in the long-term interest of consumers.

Our decision to allow accelerated depreciation is also consistent with our decision for a declining demand forecast for the 2025–30 period, and lower alternative forecast capex, which does not contain any significant growth capex. We consider that accelerated depreciation and minimising capex are both necessary to reduce to stranded asset risk.

Our final decision is to apply a modified 'base' real price increase limit approach from that applied in our draft decision, resulting in a total accelerated depreciation amount of $115 million for the 2025–30 period. This amount is calculated by summing up the following two components:

- A baseline accelerated depreciation of $77 million from shortening the economic lives of multiple long-lived asset classes for new capex for the 2025–30 period and the opening capital base as at 1 July 2025, consistent with NGR rule 89(1)(b) and (c).
- An additional accelerated depreciation amount $38 million by reducing the capital base of the 'Medium pressure services' asset class (as it faces greater stranded asset risk) to set an overall 'base' real price increase limit as a guardrail. This additional accelerated depreciation provides flexibility to promote efficient growth (including negative growth) in the market for reference services, consistent with NGR rule 89(1)(a). In our final decision, we have applied a 'base' real price increase limit of 0.5% to determine the additional accelerated depreciation amount.

3.3.1.1 Expected economic lives of JGN's assets for the 2025–30 period

JGN's standard asset lives (and remaining asset lives) reflect the period over which the assets are expected to be used until the end of their technically designed lives (technical lives). Instead of their technical lives, we may determine shorter asset lives for assets that are subject to increased stranding risk to reflect the period in which they are expected to be in economic use (expected economic lives).

We consider that the expected economic lives of JGN's pipeline assets have been affected to some extent by NSW Government's 2050 net zero emissions target. However, as NSW government policy regarding the future role of gas is still evolving, there is still a considerable degree of uncertainty about the extent to which the economic lives of JGN's assets have been affected.

Notwithstanding a legislated target date of 2050 in NSW, there is currently no evidence to suggest JGN will be decommissioned or retired completely by this date. In addition, there is also no evidence that all JGN's assets face the same level of stranding risk at the present time. As such, we consider that the reasonable approach at the present time is to assign economic lives which are longer than the 2050 target but shorter than the technical lives of the assets which vary between different asset classes.

Based on current evidence, we consider a reduced expected economic life of 50 years for JGN's high pressure (HP) pipeline asset classes[54] and 30 years for the medium pressure (MP) pipeline asset classes[55] to be reasonable for the 2025–30 period:

- Currently, there is stronger evidence for electrification and more limited evidence suggesting the long-term viability of hydrogen and/or renewable gases for residential use during the energy transition to net zero in many jurisdictions in Australia. This is also supported by early policy indications from some local councils within JGN's network area on banning new gas connections.[56] As such, we consider a reduced economic life of 30 years for MP pipelines to be reasonable, as it reflects the higher likelihood of electrification as the pathway for residential customers to transition to net zero by 2050.
- The pathway for large industrial customers is less clear. As such, we consider a reduced economic life of 50 years for HP pipelines, which is about the midpoint between 2050 and the 2105 technical life end-date, to be more reasonable.

We will reassess these shortened asset lives in the future access arrangement reviews if the gas substitution pathways or actual demand turn out to be different than expected.

3.3.1.2 The 'base' real price increase limit approach as a guardrail

As a starting point, reducing these economic lives results in $77 million of accelerated depreciation which is about 2.0% of JGN's opening capital base. This is lower than the 4.5% in the draft decision and the aggregated proportion of 6.4% for the Victorian distributors. As such, we consider an additional amount of accelerated depreciation is required so that JGN is not deterred from making efficient investments required to maintain safe and reliable services for an ageing network in the long-term interest of consumers.

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54 We determine a reduced economic life of 50 years for the 'Trunk Wilton-Sydney', 'Trunk Sydney-Newcastle', 'Trunk Wilton-Wollongong' and 'HP mains' asset class.

55 We determine a reduced economic life of 30 years for the 'Fixed-Plant Distribution', 'MP mains' and 'MP Services' asset class.

56 Waverly Council, City of Sydney, Parramatta, Canterbury-Bankstown have all proposed or implemented bans on new gas connections. See JGN, *2025 Plan*, June 2024, p. 51.

In the final decision, we determine an additional accelerated depreciation amount of $38 million to the 'Medium Pressure Services' asset class, determined by limiting the 'base' real price increase at 0.5% as a guardrail.[57]

We consider the amount of accelerated depreciation must be balanced against price impacts and affordability. There is a real risk that adopting a policy of accelerating depreciation, without clearly defined limits, would be likely to result in large and repeated increases in future gas prices. This would not align with the long-term interests of customers, as it risks the use of the network (including the number of customers) to decline faster than anticipated, which further increases the risk of asset stranding and of costs being borne by an even smaller number of customers in the future. As such, in determining the additional amount of accelerated depreciation, we have applied a limit on the real price increase as a guardrail.

We consider that this approach allows flexibility for the depreciation schedule (and in turn prices) to be adjusted in a way that better promotes efficient growth (including negative growth) in the market for reference services, consistent with NGR rule 89(1)(a). Under this approach, the short-term price impact of accelerated depreciation is limited when other costs are high (such as high interest rates). This ensures better stability of prices over time, promoting efficient use of reference services. Conversely, more accelerated depreciation can be applied when other costs are low (such as low interest rates), which would help offset some of the price impact from accelerated depreciation. This increases the likelihood of cost recovery, providing incentives for efficient investment.

Compared to the draft decision, the final decision rate of return is higher and the final decision expected inflation is lower. These updates have led to higher revenues and in turn prices for the final decision. Considering this, our final decision applies a higher 'base' real price increase limit of 0.5% compared to the 0.0% determined at the draft decision. Despite this increased limit, our final decision determines a lower total accelerated depreciation amount of $115 million compared to the $156 million at the draft decision, offsetting some of the impact of increased revenues from changes in rate of return and expected inflation being borne by JGN's customers. The higher rate of return and lower expected inflation alone has led to a $84 million (2.7%) increase in total revenue compared to the draft decision. We reduced the accelerated depreciation amount to limit the further upward pressure on prices from accelerated depreciation.

We consider our final decision accelerated depreciation amount of $115 million strikes a balance between the need for a start of accelerated depreciation, to promote efficient investment, and the need to limit the impact of accelerated depreciation on consumers, particularly at a time when energy affordability continues to be a key issue during the energy transition. This reduced amount also reflects the outlook and strength of policy signals surrounding the future role of JGN's gas network in NSW at the present time. We note that

[57] We calculate the additional accelerated depreciation amount using a 'base' real price increase limit to exclude the impact of incentive schemes, in order to preserve the intended objectives of these schemes. Any rewards from these schemes effectively reduce the accelerated depreciation amount under our price constraint approach. This may create perverse incentives for networks to not pursue efficient expenditure in the current period in return for potential higher accelerated depreciation (if any) in the subsequent regulatory period. After determining the accelerated depreciation amount, we have then added the incentive schemes amounts back to unsmoothed revenue for revenue smoothing to determine an overall real price increase of 1.0% for each year of the 2025–30 period.

unlike Victoria[58] and the ACT[59], there is currently no statewide ban on new gas connections or a gas substitution roadmap in NSW. Even after the publication of a roadmap, there may still be a period of uncertainty regarding the speed of electrification and the materialisation of this impact on gas demand. As such, we consider more accelerated depreciation at this stage is not appropriate given the evolving policy environment in NSW.

As noted in our draft decision, addressing the broader issues in the gas sector requires a holistic policy response. While accelerated depreciation can be used as a tool for reducing asset stranding risk, it has limitations and on its own cannot resolve the issues faced by the gas networks and customers from anticipated declining demand. Declining demand is ultimately the key driver of rising future network prices. So long as demand continues to decline, no affordable amount of accelerated depreciation will achieve long-term price stability.

We continue to encourage an open discussion between consumers, network businesses and governments regarding who should pay for the costs of stranded assets associated with past and future capital investments, and when, and how these costs are shared. The reasons for our decision on JGN's regulatory depreciation are discussed in Attachment 4.

3.4 Capital expenditure

Capital expenditure (capex)—the capital costs and expenditure incurred in the provision of network services—mostly relates to assets with long lives, the costs of which are recovered over several regulatory control periods. Forecast capex directly affects the size of the capital base and the revenue generated from the return on capital and depreciation building blocks.

Our final decision is to include a total capex forecast of $717.4 million ($2024–25) for the 2025–30 access arrangement period, including overheads and net of capital contributions. Our final decision approves a lower total forecast capex than JGN's revised proposed $838.1 million ($2024–25). This a reduction of $120.7 million ($2024–25) or 14%.[60]

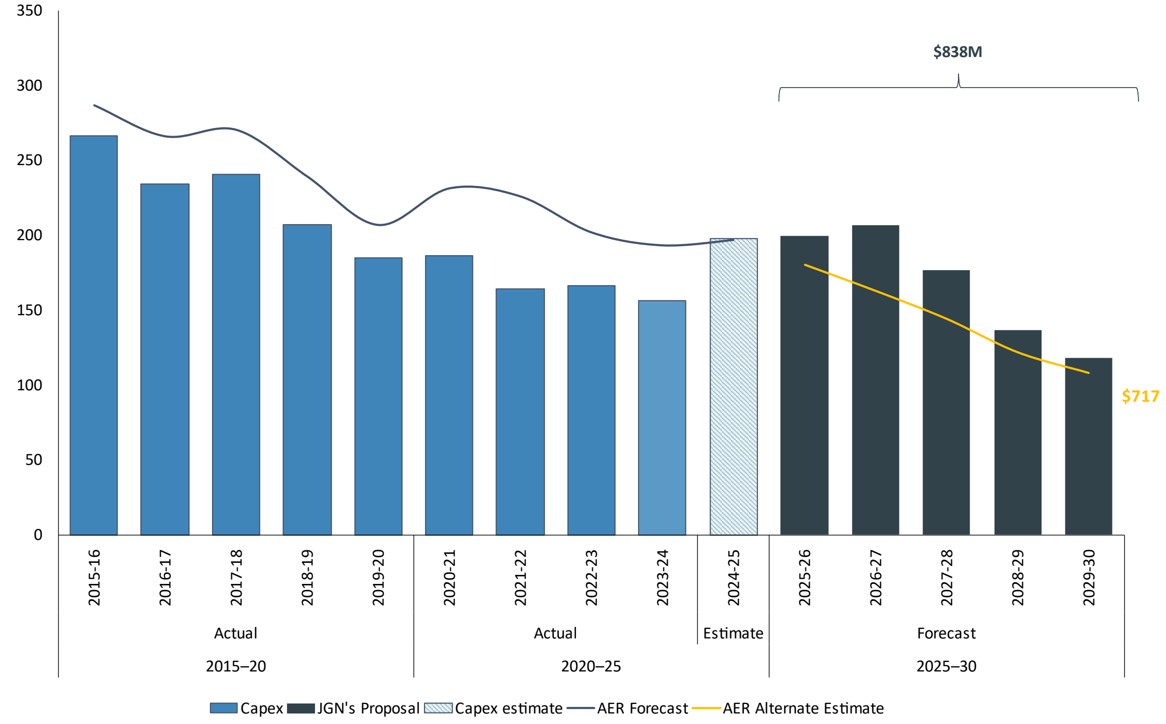
Figure 9 compares JGN's actual and forecast capex with our previous capex decisions and our final decision for the 2025–30 period.

58 The Victorian government has banned natural gas connections in all new homes that require a planning permit in the state form 1 January 2024. This policy does not apply to existing homes or new homes that do not require a planning permit. Victorian Government: *Victoria's gas substitution roadmap*, September 2023.

59 The ACT Government has banned new gas network connections in certain circumstances since 8 December 2023; ACT Government: *Canberra's Electrification pathway*, accessed on 6 November 2024.

60 These figures are net of capital contributions but inclusive of asset disposals.

Figure 9 Comparison of actual and forecast capex ($million 2024–25)



Source: AER analysis

Key drivers of our final decision alternative forecast are:

- We have not included JGN's proposed $78.9 million to fund renewable connection projects. While we accept that, if completed and supplied as specified, these projects are likely to provide a net benefit, we remain concerned there is significant commencement and completion risk for the projects. In particular, biomethane production facilities seeking connection to JGN's network are required to make significant investments in order to supply gas to customers, and there is no firm commitment from these parties to invest at this time. We considered the uncertainty surrounding these projects means that the capex proposed for these investments is not forecast conforming capex. In its revised proposal JGN proposed a fixed principle to address this issue.

  The fixed principle, if it functioned as envisaged, would require JGN to return revenue received for these projects if they did not commence in the 2025–30 access arrangement period or if the AER determined, in the 2030–35 access arrangement decision, that capex spent on these projects is non-conforming. We consider the uncertainty surrounding these projects cannot be alleviated by the fixed principle proposed by JGN as the fixed principle is inconsistent with provisions in the NGR and, therefore, the NGR would operate to the exclusion of the fixed principle.[61] We have therefore proposed the deletion of the fixed principle from the access arrangement.

- This decision does not prevent JGN from undertaking the capex in the access arrangement period and seeking to either have the capex assessed as part of the calculation of the opening capital base for 2030, or by using the speculative capex

61 NGR, r. 99(4)(b).

account. We have provided guidance that JGN may consider if it wishes to pursue these options, and this is outlined in Attachment 5 of this decision.

- We have increased JGN's proposed customer connections capex by $35.0 million, net of capital contributions (JGN proposed $276.5 million).[62] This increase is driven by our final decision on JGN's demand.[63] We forecast a higher rate of residential customer growth than JGN. This will lead to more residential customer connections. While this does increase capex, it is estimated to have a slight downward impact on bills, given it will increase forecast gas consumption.
- We have reduced JGN's proposed meter replacement capex by $49.7 million (JGN proposed $171.1 million). JGN has not demonstrated that its existing meter fleet is deteriorating at the rate forecast in its proposal. JGN has assumed that when certain families of meters pass 35 years of age, the failure rate will increase exponentially. This assumption has driven JGN's strategy to proactively replace meters over 35 years old. We acknowledge that since its initial plan, JGN has conducted meter accuracy testing which show two lots of 30-year-old meters failing. However, JGN has not been able to provide sufficient data to support the assumption that meters over 35 years of service face an exponential increase in failure rates, particularly because the sample size of meters older than 35 years is small. Our alternative estimate of $121.4 million is more in line with its historical expenditure in the current period of $111.1 million.
- We have removed JGN's scope factor allowance, which reduces total capex by $26.1 million.[64] We consider that this type of forecasting risk premium is inconsistent with the application of the CESS. In particular, JGN used a scope factor allowance in its last access arrangement and achieved a significant CESS benefit from spending less than the approved forecast. Using a scope factor allowance again risks undermining the one of the key benefits of the CESS, in that revealed information and efficiency gains should be embedded in future forecasts and shared with customers. The 2020–25 access arrangement period was the first time the CESS applied to JGN's network, meaning it was the first opportunity to observe and carry forward capex efficiencies to future access arrangement periods. It is important that revealed outcomes from the CESS are used as a basis for future decisions as a way of embedding efficiency gains in future forecasts. Removing the scope factor allowance risk allocation has resulted in a reduction across several of JGN's capex categories, including those categories we otherwise accept.

We discuss the difference between our alternative estimate and JGN's revised proposal in more detail in Attachment 5.

3.5 Operating expenditure

Opex is the operating, maintenance and other non-capital expenses incurred in the provision of pipeline services.

62 "Customer connections" here means all JGN's connections other than renewable connections.

63 Refer to Chapter 4 Forecast Demand and Attachment 12 for more detail.

64 This figure does not include the risk allocation for projects we removed entirely from our alternate estimate. In its revised proposal, JGN's total proposed scope factor allowance was $38.7 million.

Our final decision is to include a total opex forecast of $1,144.9 million ($2024–25)[65] for the 2025–30 access arrangement period, excluding ancillary reference services and including debt raising costs[66] and socialised customer abolishment costs (see section 5.2).

We are satisfied that JGN's revised opex forecast, excluding socialised customer abolishment costs and debt raising costs, of $1,122.6 million[67] satisfies the opex criteria[68] and the criteria for forecasts and estimates. [69] This is because our alternative estimate of these elements of JGN's total forecast opex, excluding socialised abolishment costs, is not materially different (0.3% or $3.6 million lower) from JGN's revised proposal. This difference from the revised proposal is mainly driven by mechanical updates to reflect current forecasts, including:

- a more recent inflation forecast from the RBA[70]
- an updated rate of change – in calculating output growth and labour price growth forecasts we have relied on customer number and Wage Price Index forecasts from our consultants, ACIL Allen and Deloitte Access Economics, respectively.
- updated forecasts of unaccounted for gas costs to reflect the demand forecast set out in Attachment 12 of this final decision.

We have therefore included JGN's revised opex forecast, excluding socialised customer abolishment costs and debt raising costs, of $1,122.6 million in our total opex forecast. We have also included $9.7 million of debt raising costs based on our final decision post tax revenue model (PTRM) calculation as discussed in Attachment 6 of this final decision.

We are not satisfied that JGN's forecast of $16.3 million for socialised customer abolishment costs meets the opex criteria and for the reasons discussed in Attachment 9 of this final decision we have determined a lower cost to be socialised per abolishment. This means that a lower forecast opex amount meets the opex criteria. Our final decision total opex forecast therefore includes a forecast of $12.7 million to reflect the approved socialised customer abolishment costs.

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65 All numbers are in $2024–25 unless otherwise indicated.

66 JGN proposed to split its current reference service into the Transportation Reference Service and Ancillary Reference Service. This section relates only to opex for gas transportation. For more details, please see: AER, *Final decision – Jemena Gas Networks (NSW) Ltd Access Arrangement 2020–25 – Attachment 1: Services covered by the access arrangement*, June 2020, pp. 5–6.

67 This is JGN's total opex forecast excluding socialised customer abolishment costs and debt raising costs.

68 Under rule 91 of the National Gas Rules (NGR), opex 'must be such as would be incurred by service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.' Where opex satisfies the test in rule 91, we say it satisfies the opex criteria.

69 Under rule 74 of the NGR, information in the nature of the forecast or estimate must be supported by a statement of the basis of the forecast/estimate. Further, forecasts and estimates must be arrived at on a reasonable basis and must represent the best forecast or estimate possible in the circumstances. Where a forecast or estimate meets the requirements of this rule, we say it satisfies the forecasts and estimates criteria.

70 RBA, *Statement on Monetary Policy – Appendix: Forecast*, February 2025.

Table 4 sets out JGN's revised proposal for opex forecast and our alternative estimate, excluding the socialised costs of small customer connection abolishments, and the difference between these forecasts.

Table 4 AER's alternative estimate compared to JGN's proposed opex forecast, excluding socialised abolishments opex ($million, 2024–25)

	JGN revised proposal	AER alternative estimate	Difference
Based on reported opex in 2023–24	**1,245.3**	**1,244.1**	**–1.2**
Base year adjustment New IFRS treatment - SaaS implementation costs in base year	–10.5	–10.5	–
Base year adjustment Incremental ICT project opex	–10.7	–10.7	.0.0
Total base year adjustments	**–21.2**	**–21.2**	0.0
2023–24 to 2024–25 increment	**22.5**	**22.5**	**–0.0**
Remove category specific forecasts	**–388.6**	**–388.3**	**0.4**
Trend: Output growth	15.3	10.4	–5.0
Trend: Price growth	17.1	15.9	–1.2
Trend: Productivity growth	–23.2	–23.2	0.0
Total trend	**9.2**	**3.1**	**–6.1**
Step change: ICT services for new recurrent projects	14.6	14.6	–
Step change: Emissions measurement – Picarro leak detection services	15.3	15.0	–0.4
Step change: Pipeline Integrity Management Program	17.0	17.0	–
Step change: License fees	–	24.1	24.1
Total step changes	**46.9**	**70.7**	**23.8**
Category specific forecast: UAG	139.3	143.0	3.7
Category specific forecast: License fees	24.1	–	–24.1
Category specific forecast: customers experiencing vulnerability	2.7	2.7	–
Total Category specific forecasts, excluding socialised abolishment costs	**166.1**	**145.6**	**–20.5**
Total opex, excluding debt raising costs and socialised abolishment costs	**1,122.6**	**1,119.0**	–3.6
Debt raising costs	9.6	9.7	0.1
Total opex, including debt raising costs, excluding socialised abolishment costs	**1,132.2**	**1,128.7**	–3.6

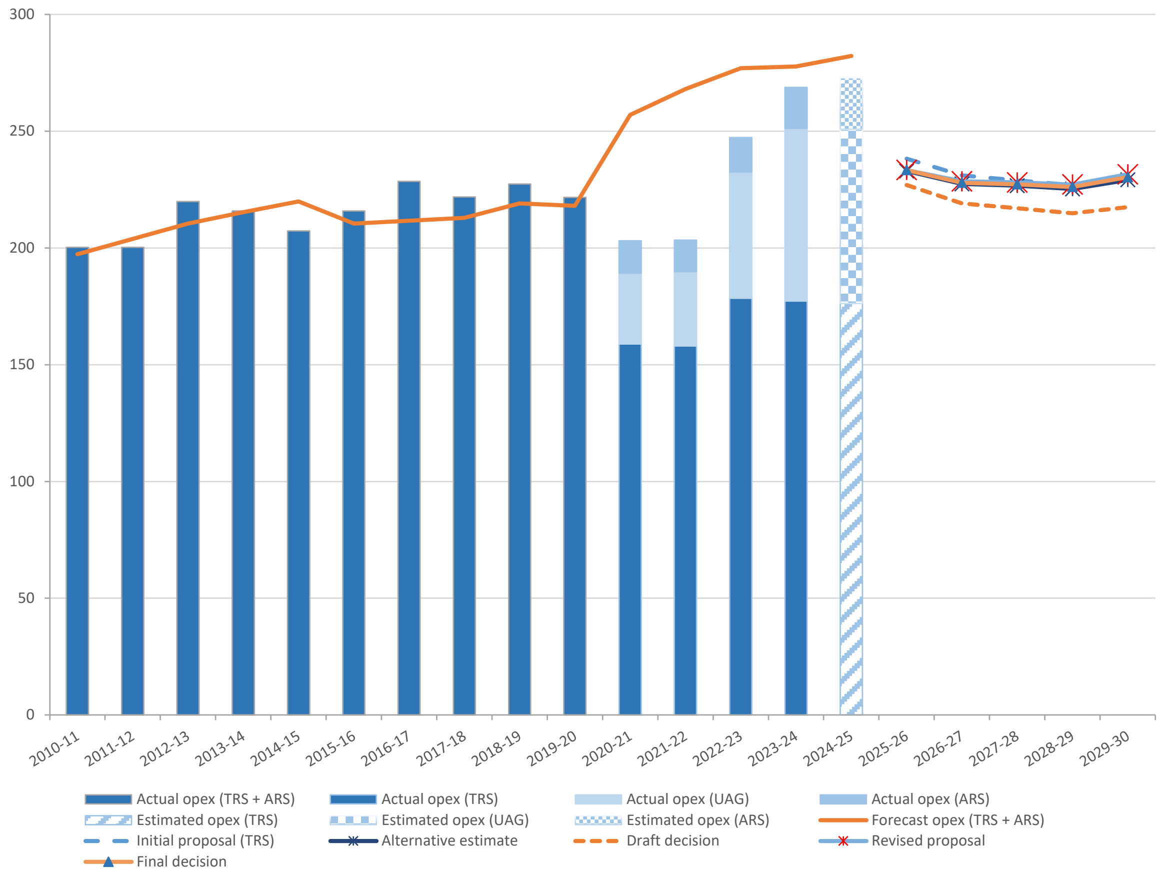
Source: JGN, *2025–30 Access arrangement revised proposal - Att 5.2M – Operating expenditure forecasting model*, January 2025; AER analysis.

Note: Numbers may not add up to total due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

Figure 10 compares our alternative estimate of opex (including socialised abolishment costs) to JGN's proposal.[71] We also show the forecasts we approved for the last two access arrangement periods and JGN's actual and estimated opex.

71 JGN's proposed opex did not include abolishments opex. It proposed abolishments as an ancillary reference service, which we have not accepted. This is further discussed in Attachment 9 of this determination.

Figure 10 Comparison of actual and forecast opex ($million, 2024–25)



Source: JGN, *Regulatory accounts*, 2010 to 2023; JGN, *2025–30 Access arrangement proposal - Att 6.3M - Operating expenditure forecasting model,* June 2024; JGN, *2025–30 Access arrangement revised proposal - Att 5.2M - Operating expenditure forecasting model*, January 2025, JGN, *Access arrangement, PTRM (multiple periods*: 2010–15, 2015–20, 2020–25); AER analysis.

Note: Includes debt raising costs and movements in provisions.

A key difference between our final decision and our draft decision is that we have included JGN's revised step change for emissions measurement – Picarro leak detection in the final decision. We are satisfied that JGN has sufficiently justified the inclusion of this step change in its revised proposal.

We discuss our assessment of JGN's revised opex forecast, and the difference between our alternative estimate and JGN's revised proposal in more detail in Attachment 6.

3.6 Revenue adjustments

Our calculation of total revenue for JGN includes adjustments under the opex ECM and CESS in its access arrangement. These mechanisms provide a continuous incentive for JGN to pursue efficiency improvements in opex and capex and provide for a fair sharing of these between JGN and users.

In our final decision, we have included a positive adjustment of $33.574 million under the CESS. Our decision is broadly consistent with JGN's revised proposal of $33.567 million, as we have only updated inputs such as CPI and weighted average cost of capital.

We have also included positive carryover amounts totalling $4.8 million ($2024–25) from the application of the ECM in the 2020–25 access arrangement period. This is the same amount that was included in JGN's revised proposal.[72]

We have also approved JGN's proposal that the ECM and CESS continue to apply during the 2025–30 period.

JGN proposes to continue excluding non-renewable connections capex from the CESS. We accept this exclusion for the same reasons we did in our draft and final decision for the 2020–25 access arrangement period, namely that customer connections expenditure is primarily driven by market forces and so is largely outside JGN's control.[73]

In our draft decision, we did not accept JGN's proposed exclusion of renewable connections. We considered renewable connections projects are not analogous to regular customer connections, because we consider JGN has greater discretion to control its spending on these projects.

However, in our final decision, we accept the exclusion of renewable connections, because these will not be funded via JGN's approved capex forecast. JGN may choose to undertake the capex in the 2025–30 access arrangement period, and to seek to have the capex assessed at part of the calculation of the opening capital base for 2030, or by using the speculative capex account. If JGN pursues these renewable gas connections, JGN is not guaranteed that this will be conforming capex[74] and included in its future opening capital base.

We consider this is sufficient incentive for JGN to approach these potential investments prudently and efficiently. Applying the CESS to this spending would discourage JGN from exploring renewable gas connections, while not providing a meaningful additional incentive for prudency and efficiency.

In our draft decision, we required JGN to include the new tiered sharing factor as described in our updated CESS guidelines to the CESS in the 2025–30 period.[75] In its revised proposal, JGN accepted our decision and has included the updated sharing factor in its access arrangement.[76]

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72 JGN, *Att 7.9M – ECM model*, June 2024.

73 AER, *JGN 2020–25 - Draft decision - Attachment 13 - Capital expenditure sharing scheme*, November 2019; AER, *Final decision - JGN access arrangement 2020–25 - Attachment 13 - Capital expenditure sharing scheme*, June 2020.

74 JGN has no assurance that we will determine its renewable connections capex is conforming. However, Appendix B of Attachment 5 provides guidance on the circumstances in which the AER may consider that the capex is conforming in a future access arrangement review. However, it is open to the AER to reach a different conclusion at that future point based on the available evidence before it.

75 AER, *Final decision - Capital expenditure incentive guideline*, 28 April 2023, pp. 4-5. Note that the new tiered sharing factor would only apply to the CESS mechanism as it applies in the 2025–30 period. It would not affect revenue increments from the CESS as it was applied in the 2020–25 period.

76 JGN, *RP – 2025–30 - Access Arrangement*, January 2025, pp. 28-9.

3.7 Corporate income tax

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

Our final decision determines an estimated cost of corporate income tax amount of $70.3 million ($ nominal) for JGN over the 2025–30 period. This is a reduction of $14.1 million (16.8%) from JGN's revised proposal of $84.4 million. The decrease is mainly driven by our final decision on a lower regulatory depreciation amount resulting from our final decision for a lower accelerated depreciation amount. Our adjustments to the return on capital (sections 3.1, 3.2 and 3.4) and the regulatory depreciation (section 3.3) building blocks affect revenues, which in turn impacts the tax calculation.

The reasons for our decision on JGN's corporate income tax are discussed in Attachment 7.

4 Forecast demand

Forecast demand plays an important role in JGN's access arrangement:

- Demand is an important input into the derivation of tariffs under the hybrid tariff variation mechanism in the 2025–30 access arrangement.[77]
- Forecast demand is also a driver of opex and capex (new connections), which inform our decision on the total revenue requirement.

The NGR require demand forecasts and estimates that are arrived at on a reasonable basis and represent the best forecast or estimate possible in the circumstances.[78]

Our final decision does not accept JGN's demand forecast for the 2025–30 period. Our alternative forecast differs from JGN's proposal by having:

- for residential customers, a higher number of new connections and a higher forecast usage per connection
- for commercial/small business customers, a slower decline in usage per connection, consistent with the historical trend, and an increased number of customers by correcting an error in the modelling (which double counted the net decline in connections).

However, our final decision is to accept JGN's demand forecast for industrial customers.

Our draft decision did not accept JGN's demand forecast, and we substituted an alternative forecast that better met the NGR requirements. In particular, our alternative forecast included:

- a lower rate of disconnections and abolishments for residential customers
- a slower decline in usage per customer.

In response to our draft decision, JGN's revised proposal updated its demand forecast. JGN forecasts a decrease in connections for residential customers (down by 0.6% over the access arrangement period) and commercial customers (down 4.9% over the access arrangement period). In its revised proposal, JGN:[79]

- updated its forecast for residential customers to include up-to-date dwelling construction data from the Housing Industry Association (HIA).
- forecast a fall in the number of new customers connecting of 15,910 from its initial proposal.
- forecast a fall in gas use per customer for each year of the access arrangement period, which was close to the rate of change the AER included in its draft decision.

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77 JGN's tariff variation mechanism allows it to vary tariffs if volumes (demand) are above or below a certain bound. Consequently, tariffs may be rebalanced using updated demand during the access arrangement period. See Attachment 10 of the draft decision for more information on the tariff variation mechanism.

78 NGR r 74

79 JGN, *RP - Att 6.1 - Demand forecast*, January 2025.

- updated the starting point for its demand forecast, based on the most recently available weather corrected demand data.
  - JGN's new starting point is 4.3% lower than the figure used in its initial proposal and the AER's draft decision. This reflects a higher-than-expected fall in demand for 2023–24.

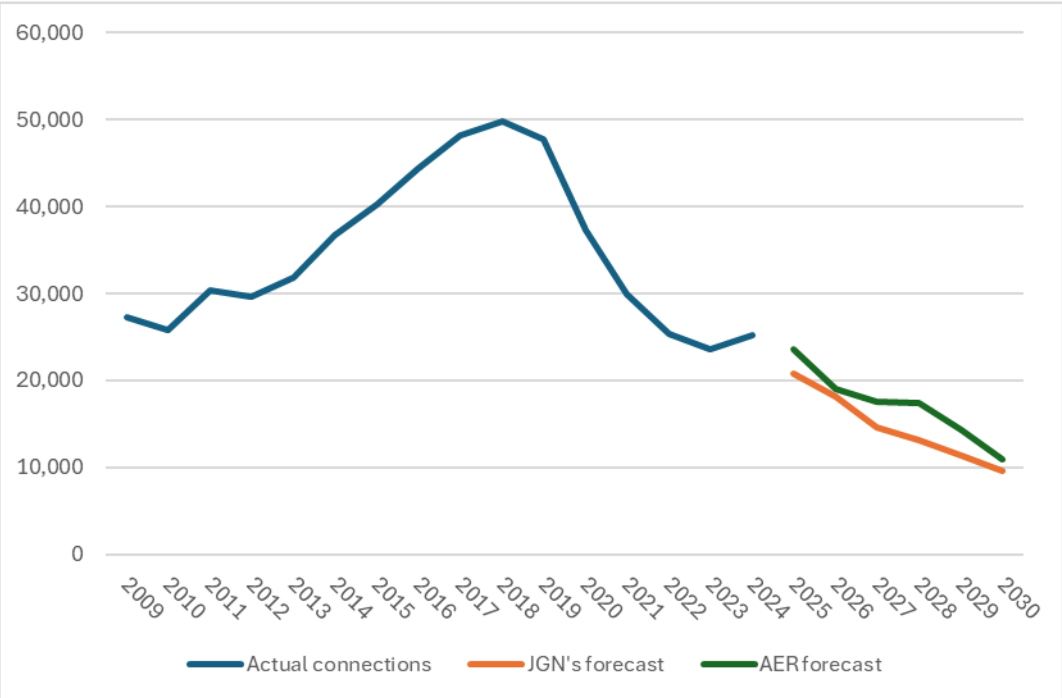
For small business customers, JGN considers the lower forecast in its revised proposal compared with the draft decision is due to different assumptions of electrification.[80]

For industrial customers, JGN has reduced its forecast due to the upcoming termination of activity by a large customer that was not known at the time of the initial proposal.[81] JGN has also adjusted its base forecast to address expected structural changes in future consumption, and provided further information on how its consultant, CORE, developed this forecast.

Residential connections

We do not consider JGN's forecast of new residential connections was arrived at on a reasonable basis, nor represents the best forecast in the circumstances. Figure 11 shows the annual number of connections for residential customers from 2009 to 2023 and the forecast from 2024 to 2030. This chart shows that the total number of connections grew year on year until 2018, after which they have fallen year on year, with a slight increase expected in 2024. It also compares JGN's forecast to our final decision, which is higher than JGN's.

Figure 11 JGN's actual and forecast new gross residential connections and AER final decision - 2009 to 2030



Source: AER analysis. JGN, *CORE Energy - RP - Att 6.2 - Demand Forecast – public*, January 2025.

80 JGN, *RP - Att 6.1 - Demand forecast*, January 2025, p. vi.

81 JGN, *RP - Att 6.1 - Demand forecast*, January 2025, p. 21.

For the draft decision, we noted that the proportion of new dwellings connecting to the network had been in decline over the long-run, and that JGN's forecast was a continuation of this trend. We accepted JGN's approach in the draft decision.

For the revised proposal, JGN's proposed reduction in new connections was higher than can be explained by applying the latest HIA dwelling commencement data. That is, the fall in new connections was disproportionate to the fall in new dwelling activity. This represents a change in the expected penetration rate (i.e. the proportion of new dwellings connecting to gas) than was considered in the draft decision. JGN noted that the difference between its forecast and the AER's alternative was that it had incorporated lag factors beyond one year to account for observed market conditions.[82] We do not consider JGN made a compelling case in support of this change, and we consider that based on the available evidence the rate of connection in the initial proposal represents a better forecast in the circumstances.

When the rate of connection in the initial proposal is applied to the latest HIA data, we forecast 12,318 additional new connections would be included in the demand forecast.

We did not accept JGN's residential disconnection forecast in the draft decision. We considered a forecast of around 78,000 disconnections was a better forecast in the circumstances. In its revised proposal, JGN has forecast approximately 78,000 residential disconnections over the access arrangement period. This is in line with our draft decision. We consider JGN's revised forecast disconnection volume for residential customers is reasonable and based on sound analysis.

Small commercial connections

We consider JGN's forecast of new commercial connections was arrived at on a reasonable basis, and represents the best forecast in the circumstances. For commercial connections, we note that there was an average of 700 per year from 2018–23. However, there is a distinct downward trajectory in new connections from 2019, where 821 new customers connected, down to 581 new connections in 2024. We consider that the forecast average of 538 new connections over the access arrangement period is reasonable, as it is in line with a long-run trend of fewer commercial customers choosing to connect gas at their place of business.

JGN's forecast for commercial/small business disconnections is largely unchanged from the draft decision. We consider JGN's forecast is reasonable, and in line with historical rates of disconnection. Consequently, we have included JGN's forecast in our final decision.

Residential demand

JGN has updated its demand forecast to include the latest weather corrected actual demand from 2023–24. In the initial proposal, residential demand per user in 2023–24 had been forecast at 19.05 GJs per customer, whereas actual weather corrected demand was 17.97 GJs per customer, or 6% lower than forecast. This observation, in turn, forms the starting point for JGN's demand forecast, and results in a lower forecast of demand than JGN included in its initial proposal.

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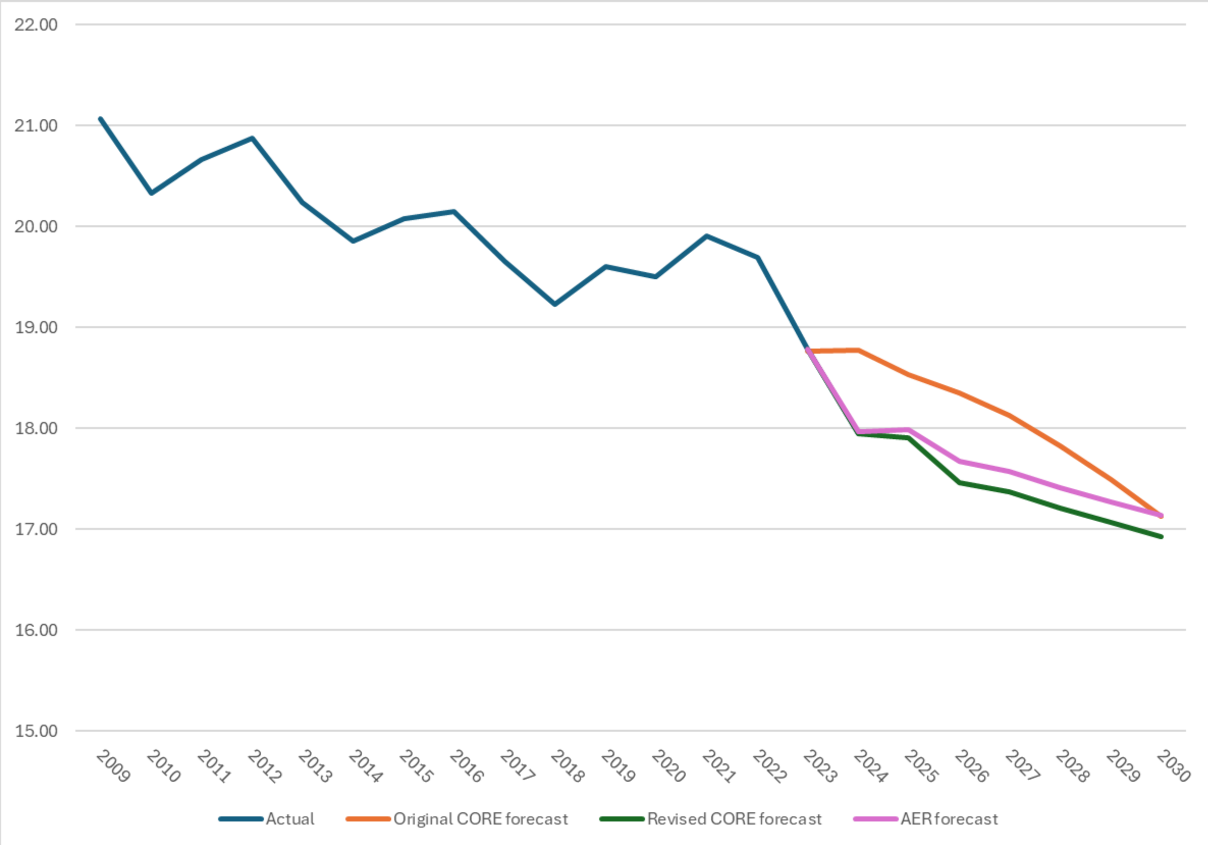
[82] JGN, *Response to IR034 demand model calculations and connections capex forecast*, April 2024, p. 3.

We consider there are likely to be structural effects (e.g. appliance switching) and transitory effects (e.g. cost of living pressures affecting customer usage) driving the lower value in 2023–24. Adopting a mid-point between the longer-term trend and actual demand from 2023–24 balances potential structural changes with transitory changes. We consider this is a better forecast than JGN's and is reasonable in the circumstances.

Consequently, we have adopted the higher starting point in our final decision, which has resulted in a higher forecast of demand per customer than proposed by JGN. Figure 12 compares the initial and revised residential demand per connection forecast from JGN's consultant CORE to our final decision.

Figure 12 Residential demand per connection, CORE Energy's original and revised forecast, and the AER's final decision



Source: AER analysis; ACIL Allen, *Review of Jemena Gas Network's revised demand forecasts*, April 2025; JGN, *CORE Energy - RP - Att 6.2 - Demand Forecast Report*, January 2025; JGN, *Core Energy - Att 8.2 - Demand Forecast Report*, April 2024.

JGN has forecast residential demand per customer to fall by 1.1% per year during the 2025–30 period. This compares with an average decline over the last 14 years of 1.0%. JGN's initial proposal forecast a faster fall in residential demand per customer of 1.6% per year.

In our draft decision, we considered a decline of around 1% a year was a more reasonable forecast in the circumstances. We consider JGN's updated assumptions for its revised proposal around usage per customer are more in line with our draft decision. We have adopted JGN's updated assumption from the revised proposal in our final decision regarding the trajectory of demand. However, due to the higher starting point described in the previous section, our final decision in each year of the access arrangement period is higher than proposed by JGN.

Small commercial demand

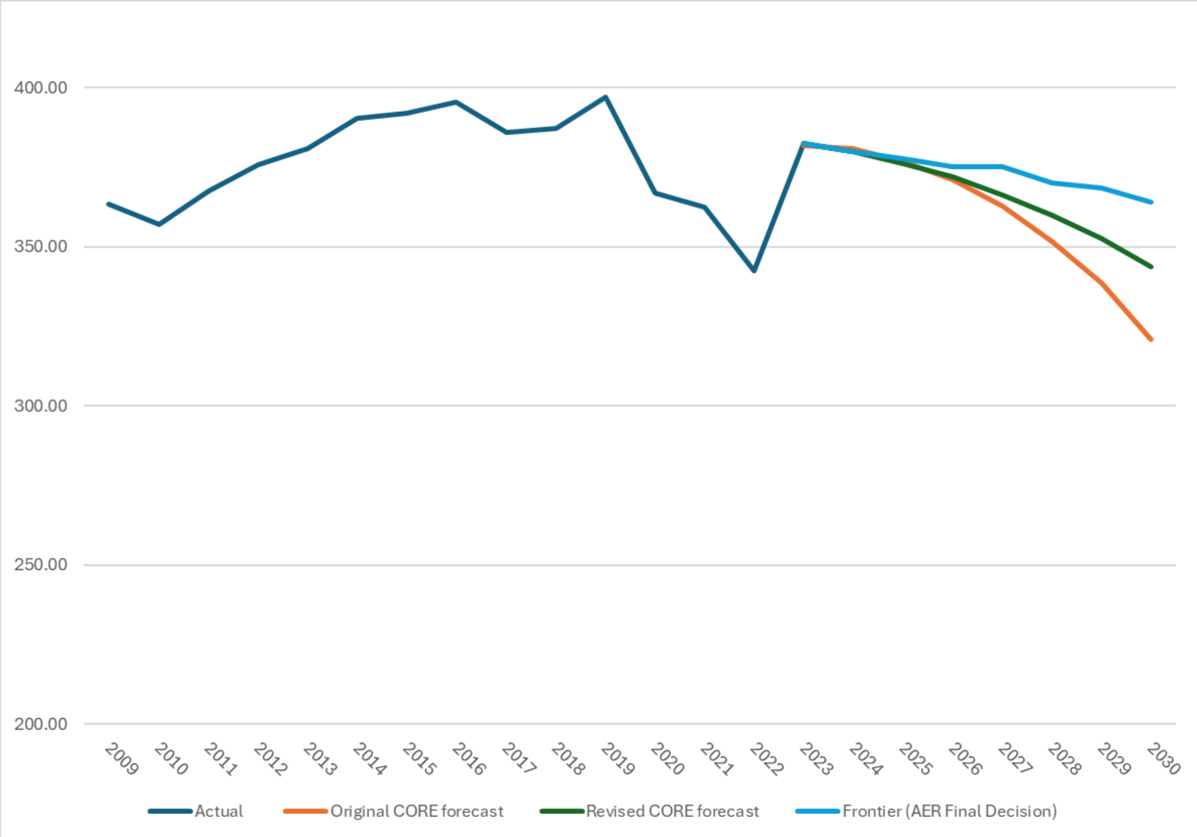
JGN has forecast commercial demand per customer to fall by 1.8% per year during the 2025–30 period. This compares with an average increase over the last 14 years of 0.3% per year. JGN's initial proposal forecast a faster fall in commercial demand per customer of 3.2% per year.

In its revised proposal, JGN (via its consultant CORE) revisited its initial forecast upwards in response to our draft decision. Between 2025 and 2030, JGN's revised small business demand per connection forecast shows an annualised rate of decline of 1.8% per annum compared to its original forecast which was projected to decline at an annualised rate of 3.2% per annum over the same period.

Separate to CORE's revised forecast, on which JGN based its small commercial demand forecast, JGN engaged Frontier Economics to review our draft decision of JGN's demand forecasts. As part of this review, Frontier reviewed and compared our draft decision alternative forecasts to CORE's and provided a set of alternative forecasts. JGN noted that the Frontier model was based on simplistic assumptions, and did not include post model adjustments to account for downward factors such as electrification.[83] JGN's revised proposal for commercial demand per customer is based on CORE's revised forecast.

[83] JGN, *Response to IR034 demand model calculations and connections capex forecast,* April 2024, p. 2.

Figure 13 Small commercial demand per connection, CORE Energy's original and revised forecast, and Frontier's forecast



Source: AER analysis. ACIL Allen, *Review of Jemena Gas Network's revised demand forecasts*, April 2025; JGN *CORE Energy - RP - Att 6.2 - Demand Forecast Report*, January 2025; JGN, *Core Energy - Att 8.2 - Demand Forecast Report*, April 2024; JGN, *Frontier Economics - RP - Att 6.7 - Demand technical note - Public*, January 2025.

We consider that the demand trajectory in Frontier's model[84] represents a better forecast than JGN's and is reasonable in the circumstances, and have used this in our forecast of demand. While we note JGN's concern that the Frontier analysis did not take into account possible downward trends in usage, we also note that demand per connection in the commercial/small business sector has been more stable over time than residential demand, which supports the proposition that any decline in demand is likely to be more gradual, and appears less sensitive to unmodelled factors, than residential demand. We also note that there has not been a dramatic fall in the latest data of the kind that has been seen in residential demand.

We accept that there is likely to be a fall in demand over the access arrangement period, but consider that this will be more gradual than JGN's forecast, in line with recent observations. The trajectory of Frontier's model best reflects recent changes in demand for this sector. Consequently, we have adopted Frontier's alternative forecast trajectory, which has resulted in a higher forecast of demand per customer than proposed by JGN.

84 JGN, *Frontier Economics - RP - Att 6.7 - Demand technical note – Public, January 2025*, p. 20.

Commercial and industrial demand

We are satisfied that JGN's forecasts for commercial and industrial Tariff D demand forecast represents the best forecast under the circumstances.

In the draft decision, we noted that this analysis was conducted outside of JGN’s demand forecasting model, and the basis for the extent of the departure was unclear. On this basis, we did not accept JGN’s industrial demand forecast and invited it to provide further information in the revised proposal.

JGN, through its consultant CORE, provided detailed information on the initiatives being undertaken in various industries that it based its demand adjustments on.[85] It also revised its analysis and reduced the annual fall in volumes from 2.15% in the initial proposal to 1.76% in the revised proposal.

We consider JGN has addressed the concerns raised in the draft decision, and its forecast of industrial demand has been arrived at on a reasonable basis.

85 JGN, *CORE Energy - RP - Att 6.2 - Demand Forecast Report*, January 2025, pp. 34-35.

5 Reference services and tariffs

JGN's access arrangement specifies the reference services it will provide, the tariffs for those services, and the other terms and conditions on which it will be provided.[86]

5.1 Services covered by the access arrangement

Determining a service to be a reference service, as compared to it being a non-reference service, makes a significant difference to how the service is regulated. Reference services are subject to our determined maximum prices, or price caps.

Services we determine to be non-reference services are not subject to price regulation, so gas networks set their own charges for non-reference services. We may be called upon to determine the tariff and other conditions of access to non-reference services if an access dispute arises.[87]

Our draft decision accepted the reference services set out in JGN's 2025−30 access arrangement proposal. Our final decision maintains those services as reference services, because they remain unchanged from our November 2023 decision to approve JGN's initial reference service proposal.[88] Our November 2023 decision set out our detailed assessment against the NGR reference service factors in the NGR.[89]

Our final decision accepts JGN's proposal to establish three customer categories, each with their own tariffs, for its small customer abolishment service. This is discussed further in section 5.2.

At a high level, JGN proposed to separate its existing single reference service into 2 reference services from 1 July 2025:

- gas transportation (haulage) including metering
- ancillary reference service.

This facilitates the application of different tariff variation mechanisms to the newly separated reference services. JGN's new ancillary reference service comprises the following separate individual services, each with its own reference tariff:

- special meter reads
- disconnection (volume customer)

86 NGR, r. 48(1).

87 NGL, Chapter 5.

88 NGR, r. 47A and 48(1)(c). JGN's resubmitted October 2023 proposal incorporated additional details not included in its June 2023 proposal, but key elements were identical across the two iterations. AER, *Final decision - JGN reference service proposal 2025–30*, November 2023.

89 NGR, r.47A(15). Under r 47A of the NGR, gas network service providers like JGN are required to submit a reference service proposal to the AER 12 months ahead of the scheduled date for submitting an access arrangement revision proposal. The AER is required to assess the reference service proposal and release its decision no later than 6 months ahead of receiving the service provider's access arrangement revision proposal.

- reconnection (volume customer)
- disconnections and reconnections (demand customers)
- abolishment
- hourly charge – non-standard requests
- expedited reconnection.

JGN proposed to continue offering an interconnection service and a negotiated service as non-reference services.

Naming of temporary and permanent disconnection services

In our draft decision, we considered there may be benefit in re-naming JGN's disconnection and abolishment services to more clearly describe the nature of those services.[90] JGN disagreed, submitting that it could result in both services being misinterpreted as disconnections, which could be confusing. [91] JGN submitted that it adopted 'abolishment' as its naming convention for the 2020−25 period, moving away from 'decommissioning and meter removal', in response to customer and retailer views. JGN submitted that using 'abolishment' is important for clarity to avoid confusion with temporary disconnections, and that it prefers to retain its current naming convention for that reason.

We remain of the view that renaming the abolishment service, to make it clear that it is a permanent disconnection, would be beneficial. However, the advent of multiple tariffs for the small customer abolishment service, with customers intending to re-connect paying the full cost and other customers paying a partially socialised tariff, adds a new dimension to this issue. We accept that it would be confusing for customers to name abolishment 'permanent disconnection' when they may intend to re-connect. At present, we understand this is the majority of customers seeking the abolishment service.

While over time we expect more customers to permanently disconnect from JGN's network, given the ancillary network service and tariff arrangements for the 2025−30 period, we accept that retaining the 'abolishment' service name remains appropriate for now.

Model standing offer changes[92]

While not part of JGN's access arrangement, it is worth noting, in this context, that JGN's recently amended model standing offer (MSO) for basic connection services has now removed 3 of its 4 residential basic connection services (new home, existing home, and residential path valve connection types). These connection services are now negotiated connections, which means that the connecting customer might now incur an upfront

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91 JGN, *Revised 2025 Plan,* January 2025, p. 63.

92 JGN's connection policy is considered in its model standing offer. The review of the model standing offer is a separate process to the review of a gas access arrangement, However, JGN submitted its model standing offer for approval along with its access arrangement proposal for the 2025–30 period, because a number of the proposed changes aligned with considerations for its model standing offer. A decision on the model standing offer was made separately.

connection charge. Previously, JGN's policy had been not to charge for small customer connections, so these MSO amendments are a step towards cost reflectivity.

We received one submission in response to our draft decision on JGN's amended MSO. In the submission the CEO of the City of Sydney stated:

> Jemena proposes revisions to their Model Standing Offer so that fewer customers qualify for a free connection, with the specific aim to reduce the growth in their asset base and lower the risk of asset stranding. This is a very welcome initiative as it would be a disincentive for some new customers to connect.[93]

We approved JGN's revised MSO as it complies with the NGR requirements for basic connection services. However, while the move towards greater direct recovery of costs from the connecting customers is a positive step, the existing requirements of the NGR limit our ability to require truly cost reflective pricing of upfront gas connections.

We note recent initiatives to reform the NGR to address some of the limitations associated with the connection charge criteria.[94] It is important that JGN ensures a positive consumer and retailer experience for the changes arising out of the updated MSO. We expect JGN to continue to work towards this.

5.2 Reference tariff setting and variation mechanism

This section first discusses the tariff structures and tariff variation mechanism proposed by JGN for gas transportation, then for ancillary reference services.

Gas transportation tariffs

Our final decision approves JGN's proposed changes to its gas transportation reference tariffs. Although we approved JGN's proposed changes in our draft decision, this was on the condition that JGN:[95]

- Provide more evidence explaining how it proposes to make further incremental changes during the 2025−30 period. This includes how far or how fast these changes will be implemented and how much additional revenue JGN intends to incrementally recover from its demand customers.
- Provide additional bill impact modelling and potential implementation pathways to achieve flat tariffs for gas transportation, for both volume and demand customers.
- Consider a tariff structure that retains a relatively high priced first price block with a single flat per-unit charge for volumes beyond that first block.

We are satisfied that JGN met these conditions in its revised proposal, where it proposed to retain the higher-priced first block and gradually transition the blocks 2 to 4 prices to a flatter

93 City of Sydney, *Submission on JGN's 2025–30 revised proposal and draft decision*, February 2025, p. 6.

94 ECA, *NGR rule change proposal*, March 2025.

95 AER, *Draft decision - JGN access arrangement 2025–30 – Overview*, November 2024, p. 31.

structure. This will occur over the course of the 2025−30 period through the annual tariff variation proposal process.[96]

JGN's revised proposal also set out the estimated bill impacts of the transition. It submitted that households consuming around 20 GJ per annum would save around $12 per annum while customers consuming 35 GJ and 100 GJ per annum would incur additional costs of around $2.50 and $120 per annum, respectively. This change would encourage higher usage customers to reduce gas consumption to avoid paying the higher (relative to current settings) tariffs in the next tariff block.

JGN proposed not to amend the declining block tariff structure for its demand (large) customers, indicating it will engage demand customers on tariff reform during the 2025−30 period in preparation for implementation in the following access arrangement period. We accept the delay in implementing a flattened tariff structure for demand customers. However, we remain of the view that a flatter tariff structure, rather than JGN's existing declining block tariff structure for demand customers, better aligns with the updated NGO. We will liaise with JGN during the 2025−30 period to understand its progress in engaging demand customers on the need for tariff reform.

On JGN's tariff variation mechanism for gas transportation, our draft decision approved JGN's proposed hybrid mechanism that blends elements of its existing weighted average price cap with elements of revenue cap regulation. However, our draft decision did not approve the continuation of licence fees and corporate tax factors being incorporated into the control mechanism as a true up.

Stakeholder submissions mostly supported JGN's proposed hybrid tariff variation mechanism, under which if actual volumes are within 5% of forecasts there is no change from the existing approach, but outside that 5% plus or minus boundary 50% of any volume driven revenue under-recovery will be carried by JGN and 50% carried by customers via higher future network tariffs. JGN further provided an illustrative pricing model incorporating the hybrid form of control which showed how it would calculate and apply the revenue true-up factor to the overall tariff control formula.[97] We have checked this illustrative model and are satisfied with the approach used by JGN in applying the new hybrid approach.

In respect of licence fees and levies being incorporated into the control mechanism as a true up, our final decision maintains our draft decision and requires JGN to exclude them from the reference tariff variation mechanism. Our reasons for this are explained in Attachment 6.

On JGN's side constraint, our final decision is to accept an amendment to its side constraint by reducing it to a base level of 2% with the condition that an extra 8% can be applied to the demand tariffs to rebalance revenue recovery to demand customers. This approach gives the effect of consistency with other gas networks and allows JGN to rebalance tariffs across demand customers as per the original intention.

96 JGN, *Revised 2025-30 Access Arrangement Proposal, Attachment 8.1, Pricing*, January 2025, p. 2.

97 JGN IR#026 - Revenue true-up factor and annual variation notice.

Ancillary reference service tariffs

Our draft decision approved JGN's proposed reference tariffs for its ancillary reference services, except for volume (small) customer connection abolishment, or permanent disconnection. JGN initially proposed to continue its abolishment service (meter <= 25m3/hr) and increase the initial 1 July 2025 charge to $1,472. Our draft decision did not accept this and instead reduced the abolishment cost to $1,104 and reduced the charge to $250, with the remaining amount above $250 to be socialised via gas transportation tariffs.

JGN's revised proposal accepted the small customer abolishment tariff of $250 and the socialisation of the remaining cost to haulage services but did not accept the reduced abolishment cost. JGN further proposed the following abolishment tariffs for different categories within the small customer abolishment service:

- $250 per meter for a Standard Residential Connection where there are no current or anticipated redevelopment, renovation or other construction works. This new charge will be partially socialised for the shortfall between $1,472 and $250 per abolishment. i.e. customer is permanently defecting from the network.
- $1,472 per meter for a Standard Residential Connection where there are current or anticipated redevelopment, renovation or other construction works. i.e. customer needs to 'abolish' for renovations to be undertaken but will re-connect.
- Individually priced for all other abolishments. i.e. for multi-tenancy sites, this facilitates low tariffs to reflect limited works.

JGN submitted that, while it accepts the need for additional abolishment services, it cannot implement these changes to its service and tariff structure on 1 July 2025 and instead proposed a one-year delay in implementation so that they would apply from 1 July 2026. The proposed rationale for the delay is the suite of system and process changes required, that necessitate technical updates by JGN and retailers across multiple platforms. The delay applies to both establishing multiple tariffs for the abolishment service and partial socialisation of the abolishment charge.

With respect to the tariff level for the fully priced small customer abolishment service, we now accept that JGN incurs additional costs compared to gas distributors in other jurisdictions, such as Victoria. We understand that, unlike its Victorian counterparts, JGN is not permitted to itself fully remediate the site of abolishment works after an abolishment has been undertaken. Rather, we understand that JGN staff perform a temporary site remediation but are then obliged to fund permanent site remediation works by local government councils. To account for this relatively higher cost, our final decision is to grant JGN a 15% uplift in the level of its fully priced abolishment tariff, to a total of $1,200.60. While this is still significantly less than JGN proposed, it is materially higher than the regulated cost of the same service in Victoria.

Our final decision is to accept the application of 3 different tariffs to the small customer abolishment service:

- small customer abolishment service of $250, remaining amount from a total of $1,200.60 (15% uplift from our draft decision to accommodate the jurisdictional cost increases for JGN) to be socialised

- cost reflective temporary abolishment service with the fee of $1,200.60 for sites where renovations or knock down rebuilds or construction works take place
- all other abolishments not covered above to be individually priced.

We accept the one-year delay in implementing the new abolishment categories and the reduced $250 abolishment charge, which is to be escalated for inflation in 2026−27 for a 1 July 2026 commencement date. We consider JGN's reasons to be acceptable in order for JGN to adequately prepare for a proper implementation on 1 July 2026.

On JGN's ancillary reference service tariff variation mechanism, JGN accepted our draft decision not to accept the proposed CPI-X mechanism. From 1 July 2025, JGN will adjust its ancillary reference service tariffs by CPI. This is consistent with other regulated gas distributors and also simpler and less prone to error.

We have proposed amendments to the control mechanism to include an automatic adjustment and true-up for the socialisation of customer abolishments.

5.2.1 Cost pass through mechanisms

Consistent with our draft decision, our final decision is to accept JGN's revised proposal that the cost pass through events available to it in the current period will continue to apply in the 2025–30 period, but with some minor revisions to provide greater drafting consistency between JGN and other network service providers, discussed in Attachment 10.

5.3 Non-tariff terms and conditions

In addition to its total revenue requirement, demand forecast and resultant tariffs, our final decision on JGN's proposed access arrangement includes an assessment of a range of non-tariff components that go to the commercial relationships between JGN and its retailers and other network users. JGN reference services are set out in the terms of its Reference Service Agreement (RSA).

In our draft decision, we approved the non-tariff components of JGN's access arrangement for the 2025–30 period.[98]

In its revised proposal, JGN accepted our draft decision and indicated that only necessary changes have been made to its RSA which have been required for inclusion of providing for 2 new tariffs to give effect to its abolishment services for small customers, as well the required updates for associated terminology changes and very minor corrections.[99]

We did not receive any submissions on our draft decision, or on JGN's revised proposal, in relation to the non-tariff terms and condition component.

Our review of JGN's revised proposal has found that only updates as required to give effect to the decision or minor corrections have occurred. Our final decision is to approve JGN's non-tariff components.

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98 AER, *Draft decision - JGN access arrangement 2025–30 – Attachment 11 – Non-tariff components*, November 2024.

99 JGN, *Revised 2025 Plan,* January 2025, p. 62.

A List of submissions

We received 13 submissions in response to JGN's revised proposal and our draft decision. These are listed below in Table 5.[100]

Table 5 Submissions received on JGN's proposal and our draft decision

Submissions
Australian Alliance for Energy Productivity
Australian Pipelines and Gas Association
Bioenergy Australia
City of Sydney
Consumer Challenge Panel, sub-panel 31
Energy Consumers Australia
Energy Networks Australia
GreenPower
Gwydir Circular Economy
Justice and Equity Centre
Opal
Optimal Renewable Gas
Sojitz

100 Submissions are available on the AER website.

Glossary

Term	Definition
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Ancillary RS	Ancillary Reference Service
capex	capital expenditure
CESS	capital expenditure sharing scheme
CCP31	Consumer Challenge Panel, sub-panel 31
ECA	Energy Consumers Australia
ECM	efficiency carryover mechanism
Handbook	The Better Resets Handbook
HIA	Housing Industry Association
HP	high pressure
ICT	Information and communication technologies
JEC	Justice and Equity Centre
JGN	Jemena Gas Networks
MP	medium pressure
MSO	Model Standing Offer
NGL	National Gas Law
NSW	New South Wales
NGO	National Gas Objective
NGR	National Gas Rules
NPV	net present value
opex	operating expenditure
RAB	regulated asset base
RBA	Reserve Bank of Australia
repex	replacement capital expenditure
Transportation RS	Transportation Reference Service
WACC	weighted average cost of capital