

Draft decision

**Australian Gas Networks (SA) access
arrangement 2026 to 2031**
(1 July 2026 to 30 June 2031)

Overview

November 2025

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Invitation for submission and next steps

In response to our draft decision, Australian Gas Networks (SA) (AGN) has the opportunity to submit a revised proposal for its upcoming 2026–31 access arrangement by 14 January 2026.

A public forum will be held on Monday, 8 December 2025 to discuss our 2026–31 gas access arrangement draft decisions. Stakeholders can register their interest online through Eventbrite.

Interested stakeholders are also invited to make submissions on our draft decision and AGN's revised proposal (once submitted) by Friday, 13 February 2026. Our final decision on AGN's access arrangement will be published by 15 May 2026.

Submissions and enquires should be sent to: AERGasResets2026-31@aer.gov.au

Alternatively, submissions can be sent to:

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

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

Parties wishing to submit confidential information should:

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

All non-confidential submissions will be published on our website.¹

¹ See the [ACCC/AER Information Policy](#) for further information.

List of attachments

This overview forms part of our draft decision on the access arrangement that will apply for 1 July 2026 to 30 June 2031 (2026–31 period) for AGN. It should be read with all parts of our draft decision.

The draft decision includes the following documents:

- Attachment 1 – Capital base, regulatory depreciation and corporate income tax
- Attachment 2 – Capital expenditure
- Attachment 3 – Operating expenditure
- Attachment 4 – Demand
- Attachment 5 – Reference services, tariffs and non-tariff components
 - Includes: Services covered by the access arrangement, reference tariff settings, reference tariff variation mechanism, and non-tariff components
- Attachment 6 – Capital expenditure sharing scheme
- Attachment 7 – Efficiency carryover mechanism

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. 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).

Australian Gas Networks Limited (SA) (ABN 19 078 551 685) (AGN) is part of the Australian Gas Infrastructure Group and provides natural gas to around 490,000 residential and business customers across South Australia.

On 1 July 2025, AGN submitted its access arrangement proposal (proposal) for the period of 1 July 2026 to 30 June 2031 (2026–31 period). This draft decision sets out our response to AGN's proposal.

South Australia and the energy transition

Our recent decisions have acknowledged that there is not a single strategy to reach the Australian Government's goal of net zero emissions by 2050 and that each jurisdiction's approach will vary according to their circumstances.

The South Australia Government has indicated its *Net zero strategy 2024–30* will guide its transition to a net zero emissions future.² It has set an ambitious target that 100% of electricity generation would be sourced from renewables by 2027, and outlined priorities to develop a clean, innovative, safe and competitive hydrogen industry.³ It has been proactive in the future of renewable gas use through policies such as the *Hydrogen and Renewable Energy Act 2023* (SA) and has to date committed to the development of 3-megawatt scale renewable hydrogen projects.⁴

In 2021, as part of the pathway to decarbonisation, AGN connected Hydrogen Park South Australia (HyP SA) to the existing Adelaide metropolitan network, delivering Australia's first blend of up to 5% renewable hydrogen by volume to around 700 homes.⁵ In 2023 and 2024, HyP SA was increased to deliver a hydrogen blend of 10% to around 4,000 homes, businesses and schools.⁶

The policy environment in South Australia is different to other jurisdictions and is an important consideration in both developing and assessing AGN's 2026–31 proposal. AGN noted that a key part of its engagement program has been customers' and stakeholders' interest in discussions around the future of gas, including what renewable gas could mean for customers in the energy transition.⁷

² Government of South Australia, [South Australia's net zero strategy 2024–30](#), May 2022.

³ Government of South Australia, [South Australia's net zero strategy 2024–30](#), May 2022, p. 4

⁴ Government of South Australia, Energy & Mining, [Leading the green economy](#), accessed on 22 October 2025.

⁵ AGN, *2026–31 Final Plan*, July 2025, p. 10.

⁶ AGN, *2026–31 Final Plan*, July 2025, p. 10.

⁷ AGN, *2026–31 Final Plan*, July 2025, p. 38.

AGN has indicated that its proposal has taken a measured approach to the current policy settings in South Australia by reflecting both the challenges and opportunities of the energy transition.⁸ Our draft decision for AGN seeks to balance the uncertainty of the future energy transition, with the current policy settings in South Australia.

Our assessment of AGN’s proposal

We do not approve AGN’s proposal, and our draft decision is to allow AGN to set gas network charges resulting in recovery of an expected \$1,187.8 million (nominal, smoothed) in revenue from consumers over the 2026–31 period. This is a decrease of \$119.6 (9.1%) from AGN’s proposal of \$1,307.4 million.⁹

Compared to the current access arrangement period (2021–26 period), our draft decision is \$33.8 million (2.9%) higher than AGN’s allowed revenue in the 2021–26 period, in nominal terms.¹⁰ This increase is driven by movements in market factors outside the control of the network including higher inflation and interest rates, which increase the revenue by \$148.8 million compared to the current period. This increase is partially offset by the reduction to controllable factors such as expenditure and depreciation, which reduce the revenue by \$108.4 million compared to the current period.¹¹

We note this is a draft decision and the guidance provided is an opportunity for AGN to consider what further information and analysis may be required to support prudent and efficient investment as part of its revised proposal.

Key elements of our draft decision include:

- Not accepting AGN’s proposed capital expenditure (capex) and substituting an alternate estimate of \$428.0 million (\$2025–26). This is \$74.9 million (14.9%) lower than AGN’s proposal. This includes placeholder amounts of zero dollars for its information and communication technology (ICT) transition project and cyber security uplift. Our decision also includes an alternate estimate of \$28 million (–27.1%) for its proposed meter replacement capex.
- Not accepting AGN’s proposed operating expenditure (opex) and substituting an alternate estimate of \$396.2 million (\$2025–26). This is \$67.9 million, or 14.6% lower than AGN’s proposal. Our alternative estimate does not include expenditure for 4 proposed step changes: renewable gas certificates for Hydrogen Park (HyP) Adelaide, non-recurrent ICT transition costs, redundant site abolishments, and cyber security. We have also included a lower forecast of unaccounted for gas costs.
- Not accepting AGN’s proposed \$30 million (\$2025–26) accelerated depreciation as we do not consider there to be sufficient evidence that AGN’s network faces significant stranding risk that currently needs to be addressed through accelerated depreciation.

⁸ AGN, *2026–31 Final Plan*, July 2025, pp. 5-6.

⁹ Our decision on an access arrangement proposal must be to either approve it in its entirety, or not at all. Our draft decision indicates whether we are prepared to approve the proposal as submitted and, if not, the nature of the amendments that are required to make the proposal acceptable to us.

¹⁰ In real terms, our draft decision represents a decrease of \$229.8 million (17.3%) in AGN’s allowed revenue compared to the current 2021–26 period.

¹¹ The sum of these impacts represent the changes to total unsmoothed revenues (\$nominal). Our draft decision reflects an increase to total unsmoothed revenue of \$40.4 million (\$nominal) compared to allowed revenue in the current period.

- Adopting AGN’s demand forecast as a placeholder and noting the Australian Energy Market Commission’s (AEMC) rule change *Updating the regulatory framework for gas connections* (Connections rule change) may require an update with AGN’s revised proposal and providing further guidance on issues we consider would further improve the forecast.
- Not accepting AGN’s proposed weighted average price cap tariff variation mechanism for its gas transportation reference service, but accepting the broad elements of AGN’s secondary proposal of a hybrid tariff variation mechanism. Within its proposed hybrid mechanism, we require AGN to adopt a 5% revenue sharing threshold (rather than the 10% proposed). The hybrid mechanism incorporates elements of both weighted average price cap and revenue cap regulation that reduce AGN’s incentive to grow the volume of gas carried by its network while mitigating year-on-year tariff volatility associated with revenue caps.
- Not accepting AGN’s proposed volume (small) customer declining block tariff and requiring that it adopt, or transition to, a simpler 2-block structure that does not implicitly reward customers for consuming more gas. For AGN’s demand (large) customer declining block tariff our draft decision is to require AGN to consider transitioning to flatter tariffs. Our draft decision on these issues, and on AGN’s hybrid tariff variation mechanism, reflect the updated NGO which now incorporates an emissions reduction objective.
- Updates for movements in market variables, such as interest rates and bond rates, currently acting to reduce the return on AGN’s capital base, whereas updates to expected inflation increased the regulatory depreciation amount.

AGN’s expenditure and demand

Demand is a critical element of a gas access arrangement and is an important input into the determination of tariffs, as well as for the opex and capex required to deliver a safe and reliable service. Forecasts indicate that gas demand in South Australia is expected to decline gradually over time and the rate of decline is expected to be slower than that projected for other jurisdictions hosting scheme gas distribution networks.¹²

AGN’s forecast demand per customer is projected to fall over the 2026–31 period at a moderate rate of 2.4% per annum, with the total number of residential customers forecast to rise by 1.2%.¹³ AGN’s demand forecast falls between the Australian Energy Market Operator’s (AEMO) 2025 Gas Statement of Opportunities Progressive and Step Change scenarios for South Australia.

Our draft decision has adopted AGN’s demand forecast as a placeholder, noting that AGN may wish to update its forecast for the impact of the AEMC’s Connections rule change, expected in December 2025.¹⁴ While the largest impact of a new rule requiring upfront cost-reflective connection charges for new customers will likely be on AGN’s connections capex, which may reduce from \$155.0 million to zero dollars, we expect AGN may also

¹² AEMO, *2025 Gas statement of opportunities*, p. 37.

¹³ AGN, *2026–31 Final Plan*, July 2025, p. 127.

¹⁴ Australian Energy Market Commission (AEMC), [Draft rule determination - National Gas Amendment \(Updating the regulatory framework for gas connections\) Rule](#), September 2025. The AEMC rule change request by Energy Consumers Australia (ECA) sought to address the problem of customer connections contributing to the capital base by introducing upfront connection charges.

adjust downwards its forecast for new connections with commensurate impact on demand. Our consultant, Frontier Economics, also identified several issues with the methodology used to forecast AGN’s 2026–31 demand, which we require AGN to address with its revised proposal.

We have reviewed AGN’s proposed capex and our draft decision raises concerns about the prudence and efficiency of the option put forward for its ICT transition project and cyber security expenditure. We also raise concerns regarding the forecasting of AGN’s meter replacement capex.

With consideration of AGN’s policy context in South Australia, we have approved its proposed \$8 million for renewable gas adaptation (hydrogen and biomethane). This largely relates to infrastructure readiness investments and provides a modest amount for potential future transformation. However, we have not accepted AGN’s proposed step change for purchase of renewable gas certificates for the proposed HyP Adelaide project given the uncertain timing of this project.

Accelerated depreciation of gas network assets

AGN’s proposal outlined how it sees renewable gas is a key part of its future.¹⁵ AGN stated that renewable gas spending ensures it can remain viable and that its proposal for additional depreciation is complementary to this because it shifts the recovery of fixed costs from the future to the present.¹⁶

AGN has framed its proposed ‘additional’ depreciation for the 2026–31 period as preparing itself for a more competitive future, rather than a response to asset stranding risk. However, we consider its proposal still aligns with the definition of economic stranding in our *Regulating gas pipelines under uncertainty information paper*.¹⁷ We consider AGN’s proposal reflects a form of accelerated recovery of depreciation in the context of asset stranding risk arising from future demand uncertainty.

Our draft decision is to not accept AGN’s proposed \$30 million accelerated depreciation for the 2026–31 period. We do not consider there to be sufficient evidence at this time to suggest that AGN’s network faces a significant stranding risk that needs to be addressed through accelerated depreciation. Both the policy environment in South Australia and AGN’s overall proposal suggest its gas network is expected to play a continued role in the transition to net zero.

Given the circumstances of individual networks, our previous decisions have approved a measured start to accelerated depreciation, balanced with forecast capex programs that did not contain significant growth capex. While accelerated depreciation can be used as a tool in managing stranded asset risk, minimising capex is also an important step for the network business to manage its stranded asset risk.

Our capex decision for AGN accepts its proposed mains augmentation projects to maintain supply pressure at the high grow areas of the network. We also accept the proposed

¹⁵ AGN, *2026–31 Final Plan*, July 2025, p. 66. See Future of gas chapter.

¹⁶ AGN, *2026–31 Final Plan*, July 2025, p. 67.

¹⁷ In the information paper, we noted that economic stranding of assets is distinct from physical stranding and is caused by a change in relative costs or prices. It refers to unused or under-utilised assets to such a degree that the owner cannot recover a full return of and on capital; AER, *Regulating gas pipelines under uncertainty information paper*, November 2021, pp. 25–26.

renewables readiness related capex, given AGN’s existing blended renewable gas program. Accordingly, we consider our draft decision on AGN’s accelerated depreciation is consistent with our decision regarding AGN’s growth and renewable readiness capex, reflecting the expected growth of its network and current policy settings in South Australia.

Stakeholder engagement in the energy transition

The energy transition means that it can be challenging for a network business to engage with stakeholders, including consumers. We acknowledge the inherent complexity of communicating issues such as form of control, tariffs, accelerated depreciation and stranded asset risk. For meaningful engagement on accelerated depreciation, we expect stakeholders are presented with an understanding of the interconnected nature of the key components of the network business’ proposal and their short-term and long-term impacts. This includes different declining demand scenarios to ensure stakeholders are provided with a comprehensive understanding of how long-term future gas prices are dependent on the trajectory and pace of declining demand.¹⁸

While AGN has engaged with its stakeholders, including consumers, on its proposed accelerated depreciation, the extent and level of collaboration is less strong compared to our observations of other gas networks’ accelerated depreciation proposals.

We note too that the Consumer Challenge Panel, sub-panel 33 (CCP33), submitted that AGN’s stage 3 workshops predominantly focused on informing AGN’s consumers of its perspective, rather than engaging them to inform its proposal.¹⁹ CCP33 also questioned the extent to which consumer understanding of the issues was tested and encouraged AGN to engage on different scenarios around the future of gas and affordability when discussing accelerated depreciation, investment in hydrogen and tariff impacts.²⁰

We note that the AEMC is consulting on a broad set of rule change proposals by Energy Consumers Australia (ECA) and the Justice and Equity Centre (JEC). A focus for both ECA and JEC is the use of accelerated depreciation to bring forward capital base recovery for gas distributors.²¹ While the rule change process will not directly impact AGN’s 2026–31 access arrangement, it is part of the context for AGN and its stakeholders.

While we acknowledge the genuine commitment undertaken by AGN in developing an engagement plan to understand its customers’ needs and expectations, we consider there are areas of further consideration for AGN as it prepares its revised proposal, and for its ongoing stakeholder engagement.

¹⁸ AER, *Final decision - JGN access arrangement 2025–30 - Attachment 4 - Regulatory depreciation*, May 2025, p 22. Section 4.4.1.7 sets out further engagement principles when engaging on the topic of accelerated depreciation.

¹⁹ CCP33, *Advice to AER - Submission on AGN 2026–31 Access Arrangement Proposal*, August 2025, p 21. CCP33 panel members include Helen Bartley and Robyn Robinson.

²⁰ CCP33, *Advice to AER - Submission on AGN 2026–31 Access Arrangement Proposal*, August 2025, pp.4 and 21.

²¹ The rule change is a combination of issues raised by ECA and the Justice and Equity Centre (JEC). ECA and JEC propose the rules to be changed to limit how networks can propose, and the AER can approve accelerated depreciation, including reform to the NGR in respect of depreciation for previous capex investments, or even to simply prohibit approaches other than ‘straight-line’ depreciation. JEC also seeks a prohibition on it unless the AER performs a redundancy assessment to manage asset stranding risk

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1 Our draft decision

AGN's proposed access arrangement sets out the services it will provide in the 5 years from 1 July 2026 to 30 June 2031 (2026–31 period), the tariffs for those services, and the other terms and conditions on which they will be provided.

Our decision on an access arrangement proposal must be to either approve it in its entirety, or not at all. Our draft decision indicates whether we are prepared to approve the proposal as submitted and, if not, the nature of the amendments that are required in order to make the proposal acceptable to us. At the centre of our decision is the forecast total revenue requirement for the provision of the regulated reference services over the next 5 years.

Our draft decision is to not accept AGN's proposal. In the sections below, we briefly outline what is driving the expected revenue in this draft decision, and the key differences between our draft decision revenue of \$1,187.8 million (\$ nominal, smoothed) compared to AGN's proposed \$1,307.4 million.²²

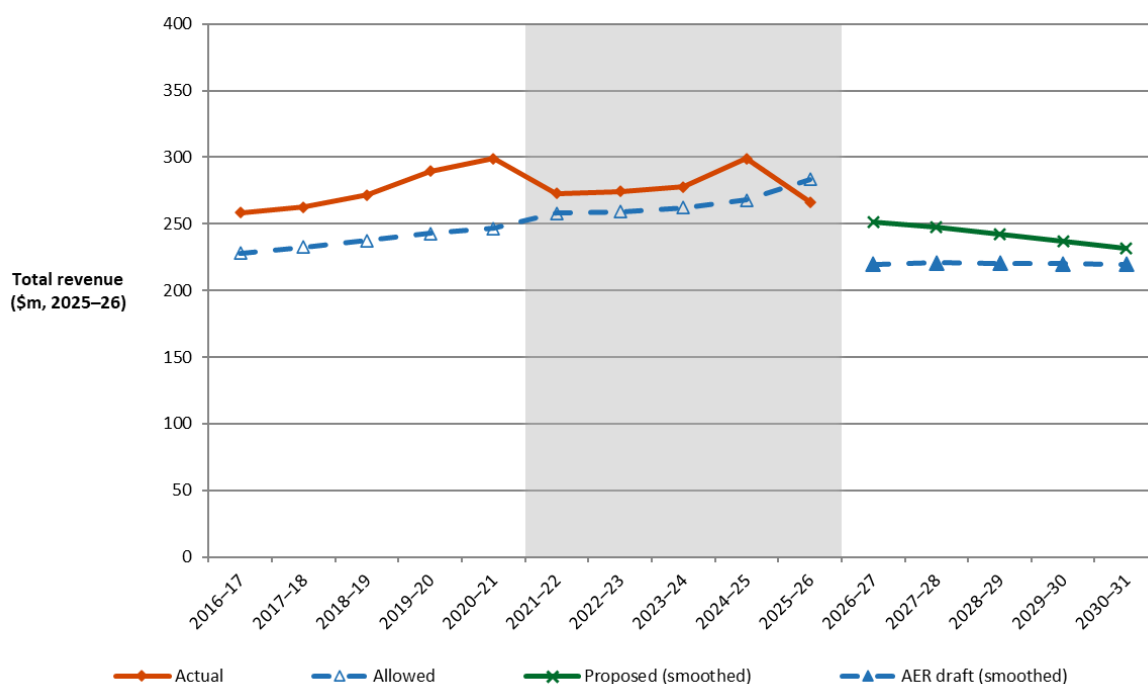
1.1 What is driving revenue

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 (2025–26) that have been adjusted for the impact of inflation instead of the nominal values above.

Where the assumptions in AGN's proposal would result in total smoothed real revenue that was \$121.7 million (9.1%) lower than approved for the current period, the estimated impact of our draft decision is a decrease of \$229.8 million (17.3%). Figure 1 shows how real revenue would change over the next 5 years under this draft decision, compared to AGN's proposal.

²² Total expected (smoothed) revenues are exclusive of Ancillary Reference Services (ARS) revenues.

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



Source: AER analysis.

There are several reasons for this reduction in revenue. Figure 2 highlights the key drivers of the change between the expected real revenue approved for AGN's 2021–26 period and that approved in this draft decision for the 2026–31 period. It shows that our draft decision provides for decreases in the building blocks for:

- return of capital (regulatory depreciation), which is \$310.0 million (83.3%) lower than the 2021–26 period. This is a key driver of the lower revenue compared to the 2021–26 period. In the 2021–26 decision, we approved \$250 million of accelerated depreciation associated with AGN's mains replacement capex program for the 2021–26 period. The residual value of the replaced assets were depreciated over a 5-year period, as these assets were no longer in use once replaced. This is the primary driver of the lower regulatory depreciation amount compared to the 2021–26 period.
- forecast opex for the 2026–31 period, which is \$41.1 million (–9.4%) lower than the 2021–26 period forecast. The decrease in the 2026–31 period is largely due to actual opex in the 2023–24 base year being lower than forecast, and because we have not included a number of AGN's proposed step changes in our alternative estimate of total opex.

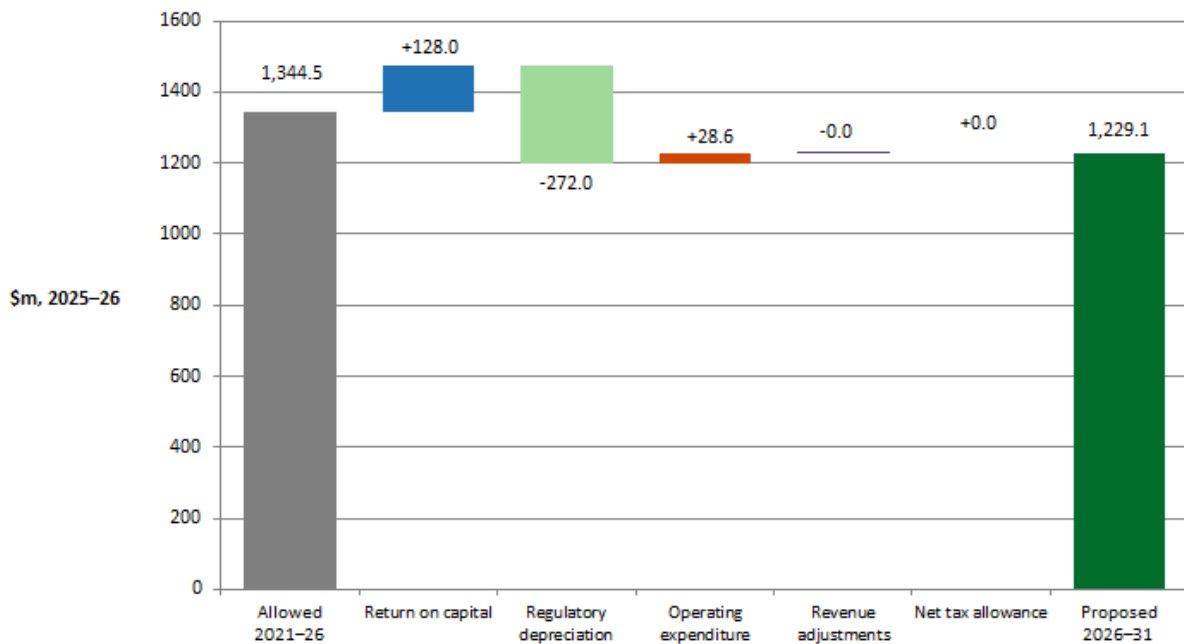
Figure 2 also shows that our draft decision provides for increases in the building blocks for:

- return on capital, which is based on the opening capital base, forecast capex and rate of return. This is \$121.1 million (23.6%) higher than the 2021–26 period. As shown in Figure 3, AGN's capital base is projected to increase in real terms over the 2026–31 period. The forecast capex for the 2026–31 period is lower than AGN's historical capex incurred in previous periods, driven by the completion of AGN's extensive mains replacement program over the past decade and reductions in augmentation and associated overheads. However, the capex amount being added to the capital base more than offsets the depreciation amount being subtracted from the capital base, leading to an increasing capital base over the 2026–31 period. The rate of return over

the 2026–31 period is higher than the 2021–26 period, which also contributes to the higher return on capital building block.

- revenue adjustments, which are \$0.4 million (5.4%) higher than the 2021–26 period, mainly due to a positive revenue adjustment resulting from the introduction of the Capital Expenditure Sharing Scheme (CESS) for the first time in the 2021–26 period. This is partially offset by the negative Efficiency Carryover Mechanism (ECM) carryover amount for the 2026–31 period.

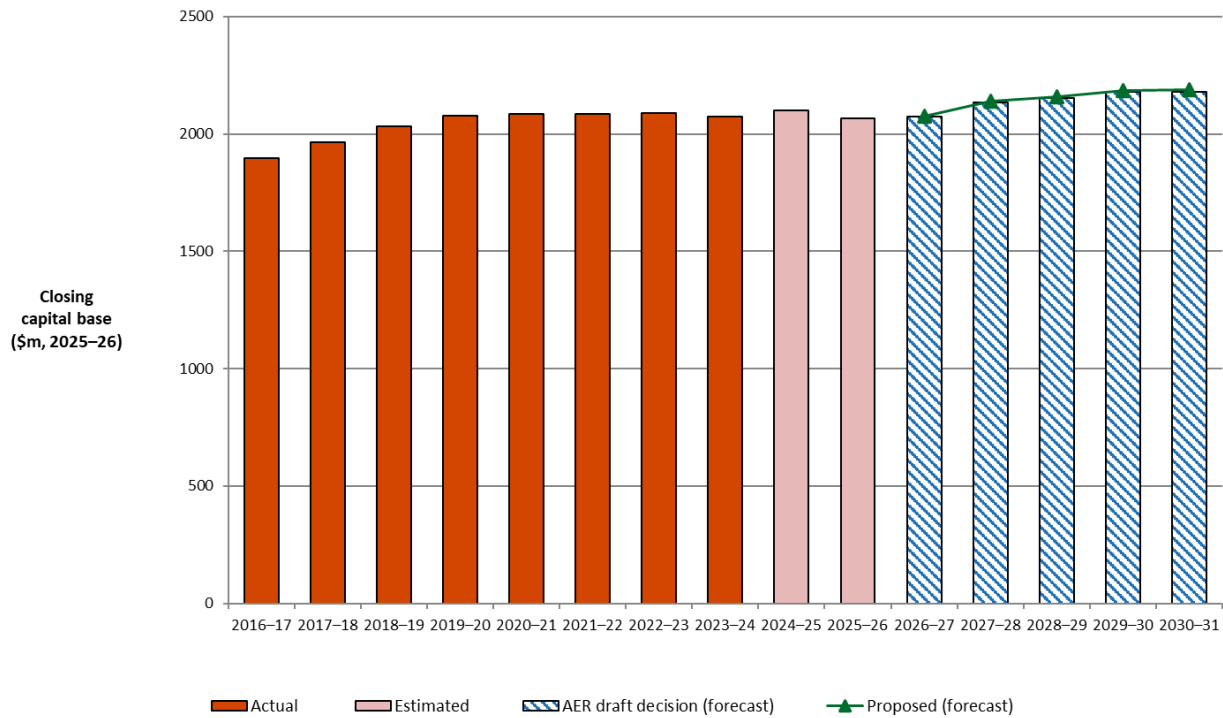
Figure 2 Changes in total revenue between 2021–26 period and 2026–31 period (\$ million, 2025–26, unsmoothed)



Source: AER analysis.

Note: Allowed revenue and proposed revenue in the chart are total unsmoothed revenue for the access arrangement period. The 2021–26 allowed revenues (including opex) are converted to real 2025–26 dollars using lagged consumer price index (CPI).

Figure 3 AGN’s capital base value over time (\$ million, 2025–26)



Source: AER analysis.

1.2 Key differences between this draft decision and AGN’s proposal

In real terms, this draft decision would allow AGN to recover a total building block revenue of \$1,116.8 (\$2025–26, unsmoothed) over the 2026–31 period.²³ We have made amendments to core components of AGN’s proposal which have led to a lower revenue outcome. For the 2026–31 period, the main areas of difference between our calculation and AGN’s proposal include:

- our reduced forecast capex, primarily driven by our placeholder amounts of zero dollars for AGN’s ICT transition project and cyber security uplift, as well as a reduction of \$10.4 million to its proposed meter replacement capex
- our reduced opex forecast, primarily driven by lower amounts for proposed step change costs and forecast unaccounted for gas costs
- our decision to not accept AGN’s proposed \$30 million accelerated depreciation. We do not consider there to be sufficient evidence at this time to suggest that AGN’s network faces a significant stranding risk that needs to be addressed through accelerated depreciation. Both the policy environment in South Australia and AGN’s overall proposal suggest that AGN’s gas network is expected to play a continued role in the transition to net zero. Our draft decision on accelerated depreciation is consistent with our capex decision, which accepts AGN’s growth and renewable readiness capex.

²³ Total building block revenue is including Ancillary Reference Services (ARS) costs.

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

- our updated calculation of AGN's rate of return, which reduced to 6.16% from AGN's placeholder estimate of 6.20%.²⁴ Together with the reduced forecast capex, the lower rate of return further contributed to the reduction in the return on capital amount of \$685.5 million (\$ nominal) determined in this draft decision compared with AGN's proposed \$695.5 million
- a lower expected inflation, based on the Reserve Bank of Australia's (RBA) August 2025 Statement on Monetary Policy (2.55% per annum compared with 2.66% in AGN's proposal). This has partially offset the reduced regulatory depreciation amount compared to AGN's proposal.²⁵

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

This draft decision marks the mid-point in our consultation on AGN's proposal, and final decision outcomes on most of these components are likely to differ. The components of forecast revenue will also change when we update our final decision for movements in market variables, such as interest rates, bond rates and inflation.

It is open to AGN to submit additions or other amendments in an access arrangement revised proposal to address matters raised in this draft decision.²⁶ The amendments must be limited to those necessary to address matters raised in our draft decision unless we approve further amendments.²⁷ They should be limited to externally driven changes that AGN was not in a reasonable position to respond to at the time of its initial proposal. We would encourage AGN, where possible, to continue to engage with its consumers on issues for consideration in its revised proposal.

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

We combine our forecast revenue requirement for AGN with forecast demand to determine its network tariffs. In simple terms, tariffs are determined by dividing costs (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. Similarly, if demand remains constant, a decrease in revenue will lead to lower tariffs.

Both revenue and demand in this draft decision are forecast to decline over the 2026–31 period. In real (\$2025–26) terms, the draft decision revenues are declining at a faster rate than demand, leading to a reduction in real tariffs of around 5.1% by the end of the 2026–31 period, or average real decreases of 1.0% per annum. However, actual tariffs are not

²⁴ Average nominal vanilla weighted average cost of capital (WACC) over the 2026–31 period.

²⁵ Despite the lower expected inflation rate, our draft decision regulatory depreciation amount is still lower than AGN's proposal. This is because our decision to reduce the forecast capex and proposed accelerated depreciation have a much larger impact on the regulatory depreciation amount.

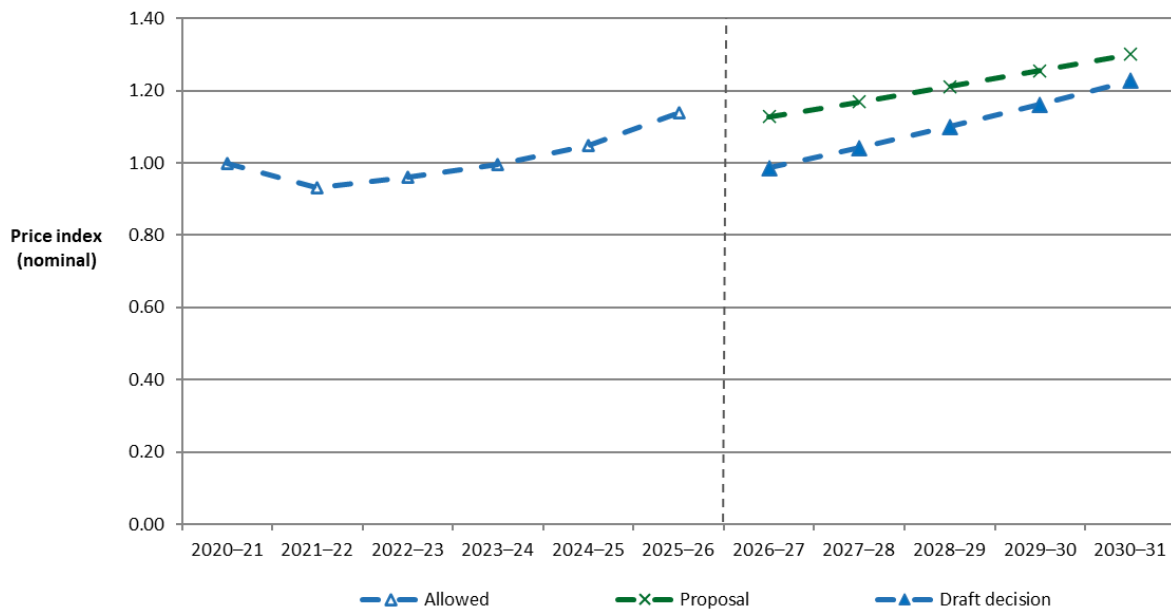
²⁶ NGR, r. 60(1).

²⁷ NGR, r. 60(2).

charged in real dollar terms and are impacted by inflation. Expected nominal revenues from our draft decision are declining at a slower rate than demand is forecast to decline. The effect of this is that this draft decision will lead to higher nominal tariffs at the end of 2026–31 relative to the current year. For illustrative purposes only—based on our expected inflation—we estimate the impact of this draft decision would be a total increase to average tariffs of around 7.7% in nominal terms by 2030–31 compared to 2025–26 levels, or an average nominal increase of 1.5% per annum.

Figure 4 shows the indicative tariff paths for AGN’s gas transportation reference services across the 2026–31 period. It compares the tariff path under this draft decision with that approved previously for the 2021–26 period, and with AGN’s current 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 (2026–27) 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.²⁸

Figure 4 Indicative reference tariffs paths for AGN’s reference services from 2026 to 2031 (Price index, nominal)



Source: AER analysis.

1.3.1 Potential bill impact

AGN’s network charges make up around 50% of its residential and 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.

²⁸ The annual reference tariff variation mechanism is discussed in section 5.2 and in Attachment 5 of this draft decision.

In nominal terms, which include the impact of expected inflation, this draft decision would lead to an increase in the distribution component of gas bills for AGN’s customers. We estimate the impact of our draft decision on the average annual gas bill, as it is today, would be:²⁹

- a nominal decrease of \$83 (7.4%) in 2026–27, followed by annual increases of between \$30–\$35 (2.9%–3.1%) from 2027–28 to 2030–31 for a residential customer. This represents an average increase of \$47 (4.2%) per annum
- a nominal decrease of \$856 (6.3%) in 2026–27, followed by annual increase of between \$308–\$363 (2.4%–2.6%) from 2027–28 to 2030–31 for a small business customer. This represents an average of \$486 (3.6%) per annum.

1.4 AGN’s stakeholder engagement

High quality stakeholder engagement is critical to developing proposals that support delivery of services that meet the needs of consumers at a price that is affordable and efficient. The Better Resets Handbook sets out principle-based expectations for considering consumer engagement, covering the nature of engagement, the breadth and depth of engagement, and clearly evidenced impact from this engagement.³⁰

Consumer engagement is an important facet of our assessment; however, we must also be satisfied the proposed forecast reasonably reflects prudent and efficient costs and a realistic expectation of future demand and cost inputs.

1.4.1 Nature of the engagement

AGN state it adopted a 5-phase approach to its engagement program and used this framework to report outcomes against its engagement activities. Phases 1 and 2 involved engaging with stakeholders to better understand their needs and consult on its proposed engagement approach leading into the development of its draft 2026–31 proposal. Phases 3 and 4 focused on consultation for the draft proposal and incorporating feedback heard during the process to finalise the proposal. Phase 5 is dedicated to engagement post-lodgement of its proposal.³¹

AGN submitted that it completed 3 phases of workshops with consumers between August 2024 to April 2025 obtaining feedback from 135 recurring customers, and conducting a total of 23 workshops.³² Consumer workshops were facilitated by KPMG to independently capture feedback and AGN submitted that it used a wide range of tools to engage and keep

²⁹ Our estimated bill impact is based on AGN’s proposed typical annual gas usage of 13 MJ per annum for residential customers and 274 MJ per annum for small business customers.

³⁰ AER, *Better resets handbook*, December 2021.

³¹ AGN SA, *2026–31 Final plan*, July 2025, pp. 32-33.

³² AGN SA, *2026–31 Final plan*, July 2025, p 34. AGN sought engagement with multicultural communities, Council of the Ageing, South Australian Federation of Residents and Ratepayers Association, St Vincent de Paul Society, Energy Users Association of Australia, South Australian Council of Social Service, Energy Consumers Australia and Ai group.

participants interested, such as subject matter expert presentations, interactive polling, surveys, and visual online collaborative tools.³³

AGN state that at the commencement of its engagement it reestablished its South Australian Reference Group (SARG) and Retailer Reference Group (RRG), and at the beginning of 2025 it combined the 2 groups to facilitate transparency and sharing of ideas.³⁴ AGN also partnered with Multicultural Communities Council of SA and hosted workshops with Culturally and Linguistically Diverse consumers in metropolitan Adelaide.³⁵

AGN indicated that feedback received from the SARG and RRG, together with consumer feedback, influenced its draft 2026–31 proposal.³⁶

AGN submitted that it also explored new methods of engaging stakeholders including partnering with Orbviz to create a digital, interactive version of its draft proposal. AGN indicated this digital tool provided stakeholders the opportunity to focus on key aspects of the plan that interested them and to provide feedback.³⁷

1.4.2 Breadth and depth of engagement

As noted above, AGN’s energy transition differs from gas network businesses in some other jurisdictions. AGN indicated its stakeholders were interested in learning more about its plans in South Australia for decarbonisation and the future of gas more broadly, including:

- how decisions made today impact future customers
- what renewable gas could mean for customers in the energy transition (for example the impact on transitioning costs)
- the potential role gas would play in a low carbon future.³⁸

AGN indicated that through its workshops and stakeholder forums it sought to discuss these issues. AGN submitted that its workshops revealed that affordability, reliability, and safety remain customers’ top priorities, followed by curiosity and caution about biomethane and hydrogen.³⁹

AGN received feedback from the SARG following its draft proposal, indicating that SARG participants considered the draft proposal lacked a clear, strategic and detailed pathway to 2050 and required a ‘missing chapter’ to outline assumptions, risks, timelines, and implications of its proposal. AGN state the SARG outlined that this information was important to justify AGN’s business-as-usual approach by considering what AGN’s vision of the future role of gas was and its long-term pathway to get there, as well as consideration of the risks where this future does not occur and what it could mean for its 2026–31 proposal.⁴⁰ AGN

³³ AGN SA, *Attachment 5.1 AGN Final Customer and Stakeholder Engagement Plan*, July 2025, pp. 13-14.

³⁴ AGN SA, *2026–31 Final plan*, July 2025, p. 42.

³⁵ AGN SA, *2026–31 Final plan*, July 2025, p. 38.

³⁶ AGN SA, *2026–31 Final plan*, July 2025, p. 44.

³⁷ AGN SA, *2026–31 Final plan*, July 2025, p. 44.

³⁸ AGN SA, *2026–31 Final plan*, July 2025, p. 38.

³⁹ AGN SA, *Attachment 5.2 Customer and Stakeholder Feedback Summary Tables*, July 2025, p. 6.

⁴⁰ SARG Review Panel, *Submission on AGN 2026–31 Access Arrangement Proposal*, August 2025, pp. 8-9.

submitted it responded in its proposal with its Future of gas chapter, outlining how renewable gas is a key part of its future.

The SARG noted that discussion on the future of gas is a complex topic that does not lend itself to simple or easy answers, and AGN received a range of responses on the topic. The SARG acknowledge ‘there is a clear preference to maintain customer choice between gas and electricity. But the implications of maintaining that choice are not well understood.’ Given the uncertainty of the future of gas, the SARG note care needs to be taken on how insights from the sessions are considered in the final plan.⁴¹

The SARG noted:

AGN’s strong customer focus shown with the emphasis on affordability, the introduction of the Priority Services Program in this period and the extensive consumer engagement in preparing the plan.⁴²

CCP33 recognised AGN’s stakeholder engagement was well organised, and detailed, noting it engaged both broadly (through its customers workshops) and deeply with the SARG. CCP33 noted the optimism with which AGN engaged its stakeholders, particularly in relation to the uncertain future of gas, which while might be business-as-usual now, could change in the future.⁴³

CCP33 outlined its concern that AGN’s testing of consumer understanding of the future of gas and accelerated depreciation was limited. CCP33 questioned whether AGN had adequately tested consumer comprehension of these issues and cautioned against assuming broad consumer support for technical proposals.⁴⁴ The SARG recommended making tariff structure design a key focus of the phase 5 engagement, with ‘deeper engagement in the final stage should explicitly acknowledge the trade-offs between fairness, affordability and broader decarbonisation objectives.’⁴⁵

The South Australian Council of Social Service (SACOSS) acknowledged the ongoing challenges facing network businesses such as AGN. SACOSS also recognised AGN had adjusted its approach and provided additional information, however raised concerns that the final 2026–31 proposal still did ‘not adequately address the risks and costs associated with a clean energy transition, nor the distribution of those risks between AGN and consumers.’⁴⁶ SACOSS reinforced its position that residential and low-income consumers must not bear the financial risks of the energy transition that properly sit with AGN.⁴⁷

SACOSS questioned whether AGN’s hydrogen and biomethane assumptions reflect a credible or consumer-protective strategy, noting that these technologies remain expensive and uncertain. SACOSS also did not support AGN’s proposed approaches to accelerated

⁴¹ SARG Review Panel, *Submission on AGN 2026–31 Access Arrangement Proposal*, August 2025, p. 6.

⁴² SARG Review Panel, *Submission on AGN 2026–31 Access Arrangement Proposal*, August 2025, p. 3

⁴³ CCP33, *Advice to AER - Submission on AGN 2026–31 Access Arrangement Proposal*, August 2025, p. 4.

⁴⁴ CCP33, *Advice to AER - Submission on AGN 2026–31 Access Arrangement Proposal*, August 2025, p. 28.

⁴⁵ SARG Review Panel, *Submission on AGN 2026–31 Access Arrangement Proposal*, August 2025, p. 33.

⁴⁶ SACOSS, *Submission on AGN SA 2026–31 Access Arrangement Proposal*, August 2025, p. 3.

⁴⁷ SACOSS, *Submission on AGN SA 2026–31 Access Arrangement Proposal*, August 2025, p. 3.

depreciation, abolishment charges, and potentially shifting from a price cap to a hybrid tariff variation mechanism, citing risks that such changes could unfairly transfer costs to vulnerable households. SACOSS supported a move toward flatter tariffs, but urged clearer communication about which consumer groups would bear cost increases.⁴⁸

ECA noted AGN should bear the risk of investments in renewable gas, and households and small business customers should not be required to pay for them as they are unlikely to benefit.⁴⁹

ECA recognised the challenges AGN faces in planning for the future of gas, but did not support the inclusion of accelerated depreciation in the proposal and urged AGN to ensure that consumers are not paying for risks that primarily benefit the network.⁵⁰ ECA stated that accelerated depreciation would only worsen things by placing additional cost and risks on households and small businesses.⁵¹

1.4.3 Clearly evidenced impact

The uncertainty of the future energy market creates challenging issues for discussion with stakeholders, which is why it is important to understand how customer values and preferences are being considered in developing AGN's proposal.

Complex topics are challenging engagement and evoke a broad range of perspectives, which we have seen in stakeholder submissions for AGN's proposal.

Overall, we see AGN's consumer engagement as thoughtful and well-planned. Re-establishment of the SARG and its independent review process, the iterative workshops, and the use of a digital engagement tool have been useful mechanisms to engage and receive feedback from its stakeholders. CCP33 commended AGN for 'engaging early with the SARG and its commitment to deep and ongoing engagement, evidenced through the review panel's report.'⁵²

We encourage AGN, given the limited time available, to consider the opportunity to engage further in the next phase on those issues identified as having the most value for stakeholders and that customer preferences continue to be reflected through its proposal now, and in future proposals.

⁴⁸ SACOSS, *Submission on AGN SA 2026–31 Access Arrangement Proposal*, August 2025, pp. 3–4.

⁴⁹ ECA, *Submission on AGN SA and Evoenergy 2026–31 Access Arrangement Proposal*, August 2025, p. 4.

⁵⁰ ECA, *Submission on AGN SA and Evoenergy 2026–31 Access Arrangement Proposal*, August 2025, p. 5.

⁵¹ ECA, *Submission on AGN SA and Evoenergy 2026–31 Access Arrangement Proposal*, August 2025, p. 6.

⁵² CCP33, *Advice to AER - Submission on AGN 2026–31 Access Arrangement Proposal*, August 2025, p. 14.

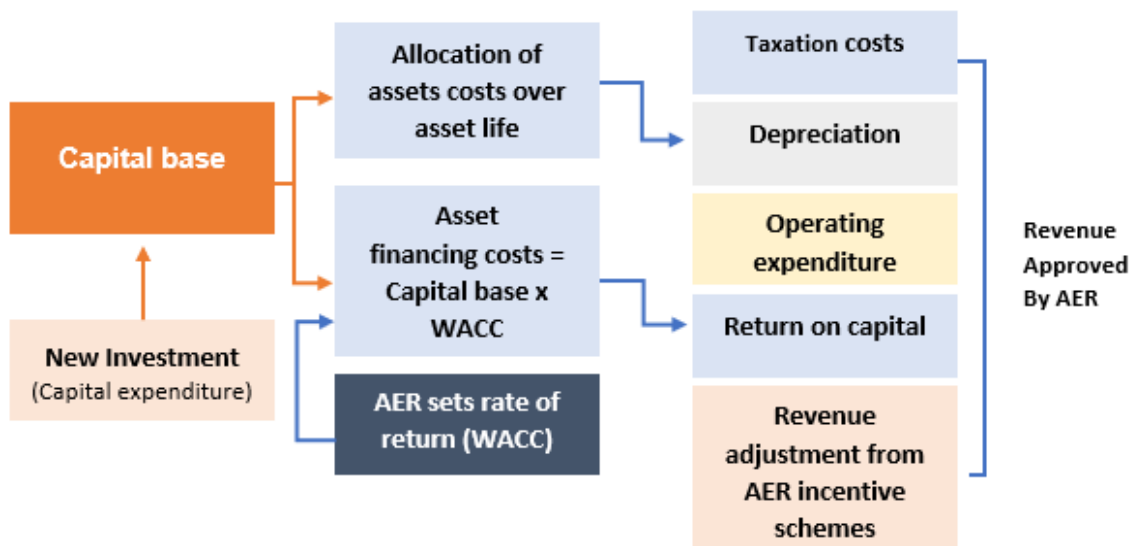
2 Total revenue requirements

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.

AGN’s proposed revenue requirement, and our assessment of it under the NGL and NGR is based on 6 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 Draft 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 draft decision on AGN's total revenue requirement is \$1,187.8 million (\$ nominal, smoothed). This is a reduction of \$119.6 million (9.1%) from AGN's proposal.

Table 1 AER's draft decision on AGN's smoothed total revenue and X factors for the 2026–31 period (\$ million, nominal)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Return on capital	124.9	129.7	136.2	142.7	152.0	685.5
Regulatory depreciation	16.7	9.7	11.3	13.7	15.7	67.2
Operating expenditure ^a	83.6	86.0	88.8	91.7	94.2	444.2
Revenue adjustments	8.9	-2.2	-0.8	-0.9	4.0	9.0
Cost of corporate income tax	0.0	0.0	0.0	0.0	0.0	0.0
Total revenue (unsmoothed, including ancillary reference services (ARS))	234.1	223.3	235.5	247.1	265.9	1,205.8
Less: ARS revenue	2.9	3.2	3.3	3.5	3.7	16.6
Total revenue (unsmoothed, excluding ARS)	231.2	220.1	232.2	243.6	262.2	1,189.3
Forecast revenue (smoothed, excluding ARS)	225.2	232.2	237.8	243.5	249.2	1,187.8
X factor ^b	15.65%	-3.00%	-3.00%	-3.00%	-3.00%	n/a

Source: AER analysis.

n/a: not applicable.

(a) Including ARS revenue.

(b) Under the CPI-X form of control, a negative X factor is an increase in tariffs in real terms. The X factor for 2026–27 is indicative only. Our decision establishes 2026–27 tariffs directly, rather than referencing a change from 2025–26 tariffs. The X factors for 2027–28 to 2030–31 will be revised to reflect the annual return on debt update.

2.2 Revenue smoothing and tariffs

AGN's tariff variation mechanism is currently a weighted average price cap which it proposed to continue, but also proposed an alternative hybrid mechanism, incorporating elements of both weighted average price cap regulation and revenue cap regulation, for the 2026–31 period. Our draft decision is to not accept the price cap approach and to accept the broad elements of AGN's proposed hybrid tariff variation mechanism, but with a 5% revenue variation threshold. We discuss the hybrid mechanism in more detail in section 5.2.

The hybrid mechanism does not change how we determine AGN's gas transportation tariffs ahead of the 2026–31 period. The revenue cap elements of the hybrid mechanism will apply during the period if actual volumes for a regulatory year are more than 5% higher or lower

than forecast. Any revenue over or under recovery driven by volumes being more than 5% higher or lower than forecast, will be split equally between AGN and customers.

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 2026–31 period. This average tariff change is known as the ‘X factor’.

Our decision on AGN’s proposal includes a determination of AGN’s total building block revenue (unsmoothed revenue), and a smoothed revenue profile across the 2026–31 period.

The X factors represent the weighted average real change in tariffs. As part of the annual reference tariff variation process applying from 2027–28, we combine the X factors determined in our decision with actual inflation to determine the nominal reference tariffs for the coming year. This means that the prices paid by consumers, and therefore the revenues received by AGN, will change with actual inflation and the annual X factor.

By smoothing revenue, 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 AGN’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.

For this draft decision, we approved lower revenues than AGN’s proposal. This is mainly driven by our reduction to AGN’s proposed opex, capex and accelerated depreciation. Our draft decision also results in lower revenues than those determined in the 2021–26 period, in real terms. While demand is also forecast to decline over the 2026–31 period, the rate of decline in forecast revenue (in real terms) is faster than that of demand. This means prices (in real terms) will decrease over the 2026–31 period.

AGN’s proposed smoothing profile provided a moderate expected initial price decrease of 3.56% in 2026–27, followed by increases of 0.93% per year for the remainder 4 years of the 2026–31 period. However, this profile resulted in a final year difference between the smoothed and unsmoothed revenues of –11.7%. This is well outside our target range of +/-3%.

We have smoothed the real decrease in forecast revenues to achieve a relatively stable price path over the 2026–31 period while reducing the final year difference as much as possible to minimise price volatility at the next period. Consequently, we have relaxed our standard target range for the final year difference between the smoothed and unsmoothed revenues. In the present circumstances, we have determined that the final year revenue difference is –5%. We are satisfied the draft decision tariff path effectively balances the aims of price path stability within the 2026–31 period and across periods.⁵³

⁵³ If our draft decision maintained a final year difference in line with AGN’s proposal and the revenue in the subsequent period remained in line or above the 2030–31 unsmoothed revenue, a significant increase to real revenues/prices would be expected at the start of the 2031–36 period (2031–32) compared to that of the end of the 2026–31 period (2030–31).

The average annual tariffs in year 1 (2026–27) determined in our draft decision is 12.6% lower in nominal terms than that proposed by AGN, reflecting the lower forecast revenue and the revenue smoothing profile determined in our draft decision. This is not necessarily indicative of final decision tariffs, which will change again with our final decisions on revenue and forecast demand. While our decision establishes tariffs for year 1 (2026–27) 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.⁵⁴

⁵⁴ The annual reference tariff variation mechanism is discussed in section 5.2 and Attachment 5 to this draft decision.

3 Key elements of our draft decision on revenue

The components of our draft decision include the building blocks we use to determine the total revenue requirement. The following sections summarise our revenue decision by building block. The attachments to this draft 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.

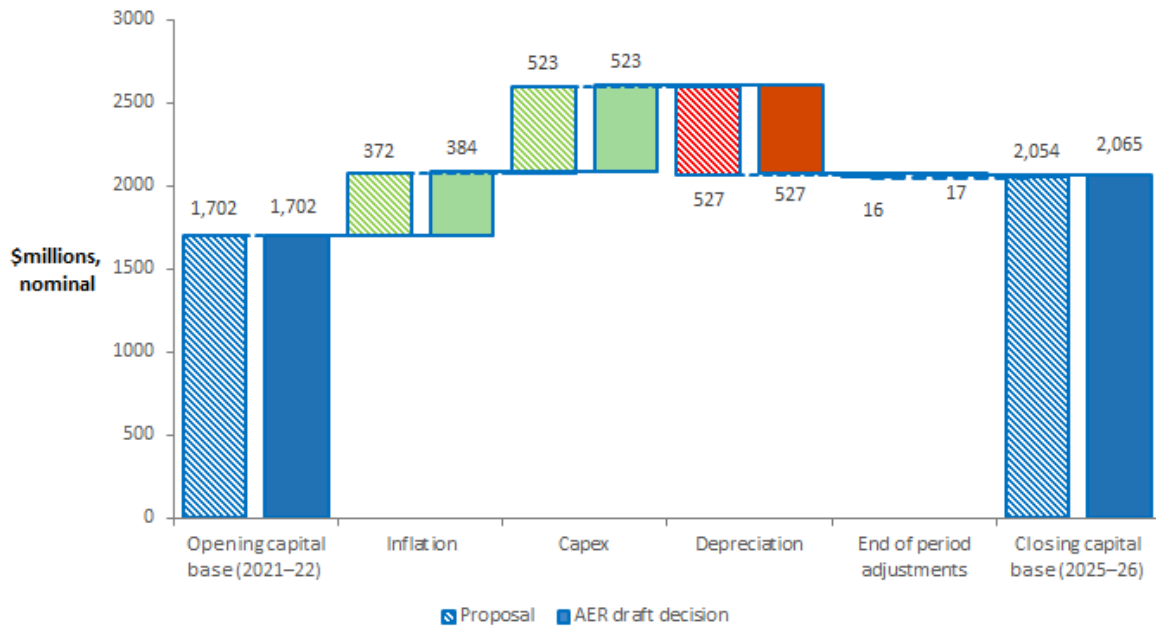
We determine an opening capital base value of \$2,065.5 million (\$ nominal) as at 1 July 2026 for AGN. This value is \$11.9 million (0.6%) higher than AGN's proposed opening capital base of \$2,053.6 million (\$ nominal) as at 1 July 2026.⁵⁵ The increase is due to our update to the roll forward model (RFM) for a higher estimated CPI of 3.00% for 2025–26 compared to the 2.42% proposed by AGN. We have updated the estimated CPI for 2025–26 with the RBA's forecast published in its August 2025 Statement on Monetary Policy, reflecting updated economic conditions.⁵⁶ The CPI for 2025–26 will be updated again, to reflect the actual CPI published by the Australian Bureau of Statistics, for our final decision.

Figure 6 shows the key drivers (\$ nominal) of the change in AGN's capital base over the 2021–26 period in its proposal compared to our draft decision.

⁵⁵ AGN, *Attachment 1.6 Roll Forward Model*, July 2025.

⁵⁶ RBA, *Statement on Monetary Policy, Table 3.1: Detailed Forecast Table*, August 2025, p. 58.

Figure 6 Key drivers of changes in the capital base over the 2021–26 period – proposal compared with AER’s draft decision (\$ million, nominal)



Source: AER analysis.

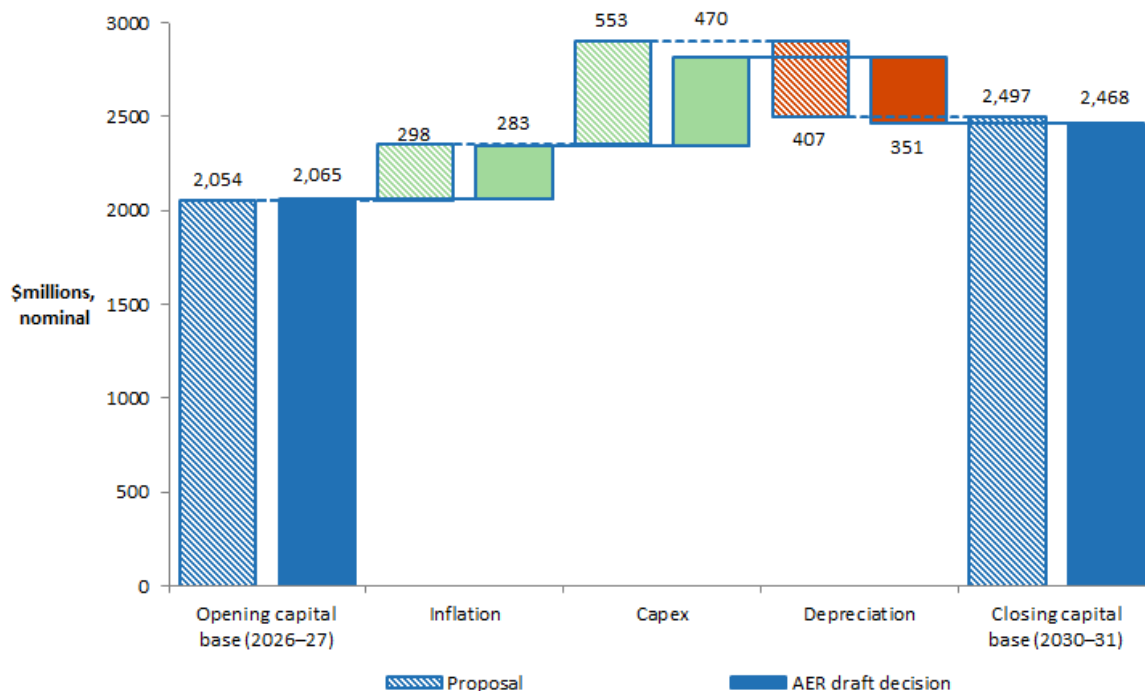
Note: Capex is net of disposals and capital contributions. It is inclusive of the half-year WACC to account for the timing assumptions in the RFM.

Figure 7 likewise shows the key drivers of the change in AGN’s projected capital base over the 2026–31 period in its proposal compared to our draft decision. Our draft decision projects an increase of \$402.6 million (19.5%) to the capital base by the end of the 2026–31 period compared to the \$443.4 million (21.6%) increase in AGN’s proposal.

We have determined a projected closing capital base of \$2,468.1 million (\$ nominal) as at 30 June 2031, which is \$28.8 million (1.2%) lower than AGN’s proposed \$2,497.0 million. This lower value is mainly due to our draft decision to reduce AGN’s forecast capex (discussed in section 3.4). This reduction is partially offset by our draft decision on a higher opening capital base as at 1 July 2026, a lower forecast depreciation and a lower expected inflation (discussed in sections 3.3 and 3.2).

The reasons for our decision on AGN’s capital base are discussed in Attachment 1 of this draft decision.

Figure 7 Key drivers of changes in the capital base over the 2026–31 period – proposal compared with AER’s draft decision (\$ million, nominal)



Source: AER analysis.

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

3.2 Rate of return and value of imputation credits

The AER’s 2022 Rate of Return Instrument (RORI) sets out the approach we will use to estimate the return on debt, the return on equity and the overall rate of return.⁵⁷

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

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

We are required by the NEL and NER to apply the RORI to estimate an allowed rate of return. For this draft decision, we have applied the 2022 RORI.⁵⁸

⁵⁷ AER, *Rate of Return Instrument (Version 1.2)*, March 2024.

⁵⁸ AER, *Rate of Return Instrument (Version 1.2)*, March 2024.

AGN’s proposal adopted the 2022 RORI.⁵⁹ The 6.05% (nominal vanilla) rate of return in this draft decision is slightly higher than the 6.04% placeholder in the proposal, reflecting the net effect of a higher risk-free rate and a lower cost of debt.

Our calculated rate of return in Table 2 applies to the first regulatory year of the 2026–31 period. A different rate of return may apply for the remaining years of the period. This is because we will update the return on debt component of the rate of return each year, in accordance with the 2022 RORI, to use a 10-year trailing average portfolio return on debt that is rolled-forward each year. Hence, only 10% of the return on debt is calculated from the most recent averaging period, with 90% from prior periods.

Our draft decision accepts AGN’s proposed risk-free rate and debt averaging periods because they are consistent with the 2022 RORI.⁶⁰

We specify these periods in confidential Appendix A and they will be used to update the risk-free rate and return on debt in the final decision.⁶¹

Table 2 Draft decision on AGN’s rate of return (nominal)

	AER’s previous decision (2021–26)	AGN’s proposal (2026–31)	AER’s draft decision (2026–31)	Allowed return over the regulatory control period
Nominal risk-free rate	1.71%	4.29%	4.34% ^a	
Market risk premium	6.1%	6.2%	6.2%	
Equity beta	0.6	0.6	0.6	
Return on Equity (nominal post-tax)	5.37%	8.01%	8.06%	Constant (%)
Return on debt (nominal pre-tax)	4.68% ^c	4.73%	4.70% ^b	Updated annually
Gearing	60%	60%	60%	Constant (60%)
Nominal vanilla WACC	4.96% ^c	6.04%	6.05%	Updated annually for return on debt
Expected inflation	2.00%	2.66%	2.55%	Constant (%)

Source: AER analysis; AER, *Final decision Attachment 3 - Rate of return - AGN (SA) access arrangement 2021–26*, 30 April 2021, p. 5; AGN, *Post Tax Revenue Model (PTRM)*, July 2025.

- (a) Calculated using a placeholder averaging period of 20 business days ending 30 September 2025, which will be updated for the final decision.
- (b) Calculated using a placeholder averaging period of 20 business days ending 30 September 2025, which will be updated for the final decision.
- (c) Applied to the first year of the 2021–26 period.

⁵⁹ AGN, *AGN SA 2026–31 Final Plan*, p. 117.

⁶⁰ AER, *Rate of return Instrument (version 1.2)*, March 2024, cll 7–8, 23–25.

⁶¹ AER, *Draft decision - AGN (SA) access arrangement 2026–31 - CONFIDENTIAL Appendix A - Rate of return*, November 2025.

Debt and equity raising costs

In addition to compensating for the required rate of return on debt and equity, we provide an allowance for the transaction costs associated with raising debt and equity. We include debt raising costs in the opex forecast because these are regular and ongoing costs which are likely to be incurred each time service providers refinance their debt. On the other hand, we include equity raising costs in the capex forecast because these costs are only incurred once and would be associated with funding the particular capital investments. Our approach to forecasting debt and equity raising costs is set out in more detail in our past determinations.⁶² AGN has proposed to use our approach to estimate debt and equity raising costs.⁶³

Our draft decision is to apply a debt raising cost of 8.65 basis points per annum, which has been used to calculate the debt raising costs included in total forecast opex (see section 3.5).

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

Imputation credits

Our draft decision applies a value of imputation credits (gamma) of 0.57, as set out in the 2022 RORI.⁶⁴

Expected inflation

As set out in Table 3, our estimate of expected inflation is 2.55%. It is an estimate of the average annual rate of inflation expected over a 5-year period based on the outcome of our 2020 inflation review.⁶⁵ AGN's proposal also adopted our approach.⁶⁶

Table 3 Draft decision on AGN's forecast inflation (%)

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

Source: AER Analysis; [RBA, Statement on Monetary Policy Table 3.1: Detailed Forecast Table](#), August 2025, accessed 8 October 2025.

Our draft decision uses the Reserve Bank of Australia's (RBA) August 2025 Statement on Monetary Policy (SMP) which contains a consumer price index (CPI) forecast for the year-ending June 2027. This means the first year of the 2026–31 period is based on RBA forecasts and, thereafter, a linear glide-path from year 2 to the mid-point of the RBA's inflation target band of 2.5% in year 5.

⁶² AER, *Draft Decision Attachment 3 - Rate of return - Ergon Energy - Distribution revenue proposal 2025–30*, 23 September 2024, pp. 4-6.

⁶³ AGN, *Post Tax Revenue Model (PTRM)*, July 2025.

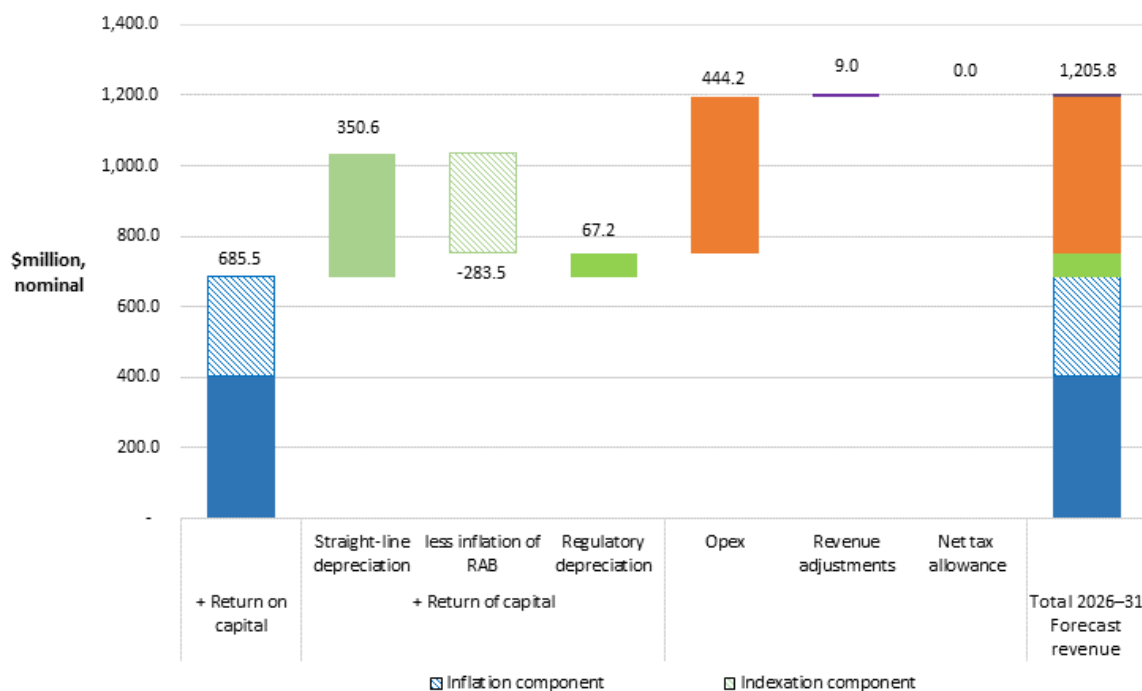
⁶⁴ AER, *Rate of return Instrument (version 1.2)*, March 2024, cl. 27.

⁶⁵ AER, *Final position, Regulatory treatment of inflation*, December 2020.

⁶⁶ AGN, *Post Tax Revenue Model (PTRM)*, July 2025.

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

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



Source: AER analysis.

Note: ARS revenue is included in opex.

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 AGN, we include an amount for the depreciation of the projected capital base.⁶⁷ Under the building block framework, regulatory depreciation consists of the net total of the straight-line depreciation less the indexation of the capital base.

We determine a regulatory depreciation amount of \$67.2 million (\$ nominal) for AGN for the 2026–31 period. This is \$42.3 million (38.7%) lower than AGN’s proposed \$109.5 million.

This reduction is primarily due to our draft decision to not accept AGN’s proposed accelerated depreciation of \$30 million (\$2025–26) for the 2026–31 period. It also reflects our draft decision on a lower forecast capex (discussed in section 3.4).

⁶⁷ Under r. 76(b) of the NGR, depreciation is one of the building blocks for determining total revenue.

The reasons for our decision on AGN’s regulatory depreciation are discussed in Attachment 1 of this draft decision.

3.3.1 Accelerated depreciation of gas network assets

Our draft decision is to not accept AGN’s proposed \$30 million (\$2025–26) accelerated depreciation for the 2026–31 period. We do not consider there to be sufficient evidence at this time to suggest that AGN’s network faces significant asset stranding risk that needs to be addressed through accelerated depreciation. Both the policy environment in South Australia and AGN’s overall proposal suggest that AGN’s gas network is expected to play a continued role in the transition to net zero.

Given the unique circumstances of individual networks, our previous decisions have considered a measured start to accelerated depreciation, balanced with forecast capex programs that did not contain significant growth capex. While accelerated depreciation can be used as a tool in reducing stranded asset risk, minimising capex is also an important step for the network business to manage its asset stranding risk.

Our capex decision for AGN is to accept its proposed mains augmentation projects as it will provide flexibility to accommodate future growth in subsequent periods if required. We also accept the proposed renewables readiness related capex, given AGN’s existing blended renewable gas program and the continued support from the South Australia Government. Accordingly, our draft decision on accelerated depreciation is consistent with our decision to accept AGN’s growth and renewable readiness capex, reflecting the current outlook and policy settings.

3.4 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 draft decision is to include a total capex forecast of \$428.0 million (\$2025–26) for the 2026–31 period, including overheads and net of capital contributions. Our draft decision approves a lower total forecast capex than AGN’s proposed \$503.0 million (\$2025–26). This is a reduction of \$74.9 million (\$2025–26) or 14.9%.

Table 4 outlines our alternative estimate of forecast capex and compares this to AGN’s proposed forecast by capex category

Table 4 AER draft decision by capex category (\$ million, 2025–26)

Category	AGN proposal	AER draft decision	Difference over capex category (%/%)	
Connections	155.0	155.0	-	-
IT	92.3	28.8	-63.5	-68.8%
Other Network	91.9	91.9	-	-
Mains replacement	84.9	84.9	-	-

Category	AGN proposal	AER draft decision	Difference over capex category (\$/%)	
Meter replacement	38.4	28.0	-10.4	-27.1%
Overheads	22.6	21.6	-1.0	-4.4%
Other non-network	7.7	7.7	-	-
Mains augmentation	6.4	6.4	-	-
Telemetry	3.8	3.8	-	-
Gross Total	503.0	428.0	-74.9	14.9%
Less Customer contributions connections	-	-	-	-
Less Disposals	-	-	-	-
Net Total	503.0	428.0	-74.9	14.9%

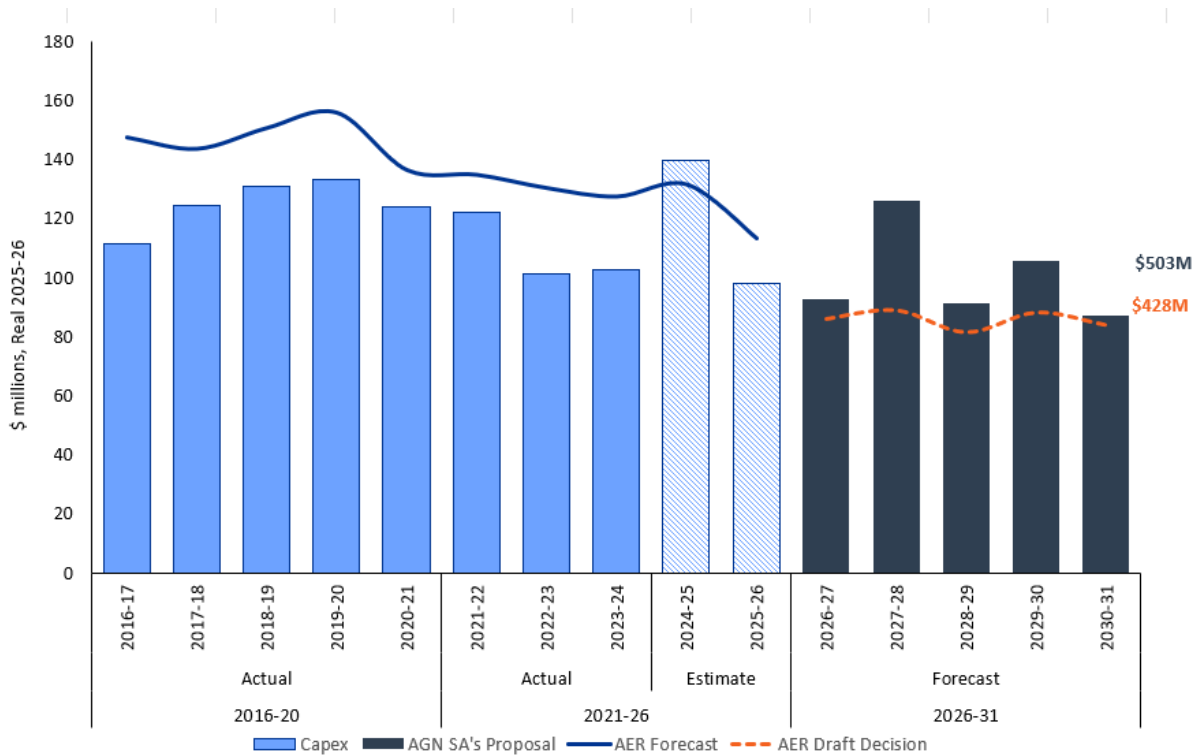
Source: AGN (SA)'s capex model and AER analysis.

Note: Numbers may not sum due to rounding.

Figure 9 compares AGN's actual and forecast capex with our previous capex decisions and our draft decision for the 2026–31 period.

AGN are forecasting \$503.0 million in capex for the 2026–31 period, this is \$45.0 million or 8.3% less than the current access arrangement period. This reduction is being driven by the completion of AGN's extensive mains replacement program over the past decade and reductions in augmentation and associated overheads. These have been offset by increases in ICT and meter replacements, which have been the subject of our review and are considered in this draft decision.

Figure 9 AGN’s historical and forecast capex (\$ million, 2025–26)



Source: AER RIN Database, AER Analysis.

Note: Nominal figures converted to real dollars 2025–2026.

Key drivers of our draft decision alternative forecast are the inclusion of:

- an alternative amount of zero dollars as a placeholder for AGN’s proposed ICT transition project (\$62.0 million) and the cyber security uplift.
 - we are concerned about the prudence and efficiency of the proposed option AGN put forward for its ICT transition project. The proposed option included significant costs for transferring systems over from its contractors APA, including labour and risk allowances. We seek further information on the efficiencies of AGN replicating and operating a stand-alone environment compared to its proposed fully merged system. Further, we consider there remains uncertainty about which costs AGN is seeking to recover. AGN should only be seeking to recover expenditure to maintain its existing ICT services and not the costs to transition those services from APA to the broader Australian Gas Infrastructure Group (AGIG). AGN’s ICT appears to be owned and operated by AGIG, with AGN utilising these facilities to operate its gas network. We need to be satisfied the regulated services recovered from customers are properly attributed to the regulated service provider, AGN, rather than another entity.
 - AGN is currently compliant with its cyber security obligations under the *Security of Critical Infrastructure Act 2018*. We consider AGN has not provided sufficient information, including consumer benefits, to demonstrate that a further cyber security uplift is necessary. We are also unclear as to whose costs AGN is seeking to recover for cyber security requirements, like the ICT transition project. We require AGN to provide further information on its regulated structure in its revised proposal.

- an alternative estimate of \$28.0 million for meter replacement capex (a reduction of \$10.4 million on AGN's proposed \$38.4 million). We have reduced the proactive domestic meter replacement to reflect actual meter replacements for 2021–26. We consider there was incomplete data on installation years and lifespans of meter families, as well as over-forecasting in meter replacements. Also, we do not accept AGN's digital meter program for inaccessible places as this affects only 1% of AGN's 450,000 customers and AGN have several alternative options to acquire meter readings from its customers.

We have included AGN's proposed \$155.0 million (\$2025–26) for connections capex in the total forecast capex as a placeholder. We consider AGN's forecast customer numbers to be reasonable, however, our decision is a placeholder because the AEMC has made a draft rule change in response to a rule change request from ECA.⁶⁸ This rule change request seeks to require gas network distributors to charge newly connecting retail gas customers cost-reflective connection charges upfront. We expect the final rule change to come into operation in December 2025. This may mean that from 1 July 2026, being the commencement of the 2026–31 access arrangement, AGN will be required to charge customers for connections up front and a forecast of connection capex, recovered from all customers, will no longer be necessary. Subject to the AEMC's final decision on the rule change, we would expect AGN to remove the forecast connection costs for its revised proposal.

AGN also proposed \$8 million for renewable gas adaption to its network for new supply projects (hydrogen and biomethane) to emerge over the next period in line with resource availability. This is largely infrastructure readiness investments such as weld procedure and hardness testing, incompatible parts replacement and pipeline repair equipment. We received submissions from SACOSS, the SARG, ECA and the Energy and Water Ombudsman of South Australia that raised concerns about the use of hydrogen as a future gas replacement. However, given AGN's existing blended renewable gas program our draft decision is to accept this modest renewable readiness expenditure.

We discuss our decision on AGN's capex proposal in more detail in Attachment 2 and our decision on AGN's demand forecasts in Attachment 4.

3.5 Operating expenditure

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

Our draft decision is to not accept AGN's total opex forecast of \$464.1 million (\$2025–26)⁶⁹ for the 2026–31 period, excluding ancillary reference services and including debt raising costs. This is because our alternative estimate of forecast total opex of \$396.2 million is materially lower (\$67.9 million, or 14.6%) than AGN's total opex forecast proposal. Therefore,

⁶⁸ AEMC, *Draft rule determination - National Gas Amendment (Updating the regulatory framework for gas connections) Rule*, September 2025.

⁶⁹ All numbers are in \$2025–26 unless otherwise indicated.

we consider AGN's total opex forecast does not reasonably reflect the opex criteria⁷⁰ and the forecasts and estimates criteria.⁷¹

Table 5 sets out AGN's opex proposal, our alternative estimate for the draft decision and the differences between these forecasts.

Table 5 Comparison of AGN's opex proposal and our alternative opex estimate

	AGN'S proposal	AER alternative estimate	Difference
Based on estimated opex in 2024–25	368.7	365.6	-3.0 (-0.7%)
2024–25 to 2025–26 increment	3.9	4.4	0.4 (0.1%)
Remove category specific forecasts	-33.9	-34.0	-0.1 (-0.0%)
Trend: Output growth	2.9	2.8	-0.1 (-0.0%)
Trend: Price growth	7.2	5.2	-2.0 (-0.4%)
Trend: Productivity growth	-4.2	-4.0	0.2 (0.0%)
Total trend	5.9	4.0	-1.9 (-0.4%)
Step change: Purchase of Renewable Gas Guarantee of Origin Certificates (RGGOs)	26.0	–	-26.0 (-5.6%)
Step change: Overheads to be expensed (capex to opex)	32.0	32.0	–
Step change: Transition from APA - AGN IT costs	18.5	–	-18.5 (-4.0)
Step change: Cyber security (Data privacy/security & Access control)	1.2	–	-1.2 (-0.3%)
Step change: Application upgrades & enhancements	4.1	4.1	–

⁷⁰ Under rule 91 of the 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.

⁷¹ Under rule 74 of the NGR, information in the nature of a 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.

Step change: Abolishment of redundant sites	4.6	–	–4.6 (–1.0%)
Total step changes	86.5	36.1	–50.3 (–10.8%)
Category specific forecasts	27.9	14.6	–13.2 (–2.9%)
Total opex, excluding debt raising costs	458.9	390.7	–68.2 (–14.7%)
Debt raising costs	5.1	5.5	0.3 (0.1%)
Total opex, including debt raising costs	464.1	396.2	–67.9 (–14.6%)

Source: AGN, 2026–31 Access arrangement proposal – Attachment 8.1 Opex Forecast Model, June 2025; AER analysis.

Note: Numbers may not add up to total due to rounding. Values of '0.0' and '–0.0' represent small non-zero values and '–' represents zero.

The key differences between AGN's proposed opex forecast, and our alternative estimate are that we have:

- not included amounts for 3 step changes as we are not satisfied AGN has provided sufficient information to justify the prudence and efficiency of proposed expenditure, including:
 - purchase of renewable gas certificates for the proposed HyP Adelaide project
 - non-recurrent IT transition costs
 - abolishment of redundant sites.
- not included the cyber security step change, which we consider to be an immaterial change to an existing category of expenditure, and therefore would double count forecast expenditure likely to be accounted for through the trend growth component of total opex
- adjusted the unaccounted for gas forecast to reflect the benchmark wholesale gas price reported in AEMO's 2025 Gas Statement of Opportunities.

We have also applied minor mechanical updates to inputs for input price growth (e.g., wage price index forecasts) and a more recent inflation forecast from the Reserve Bank of Australia (RBA).⁷²

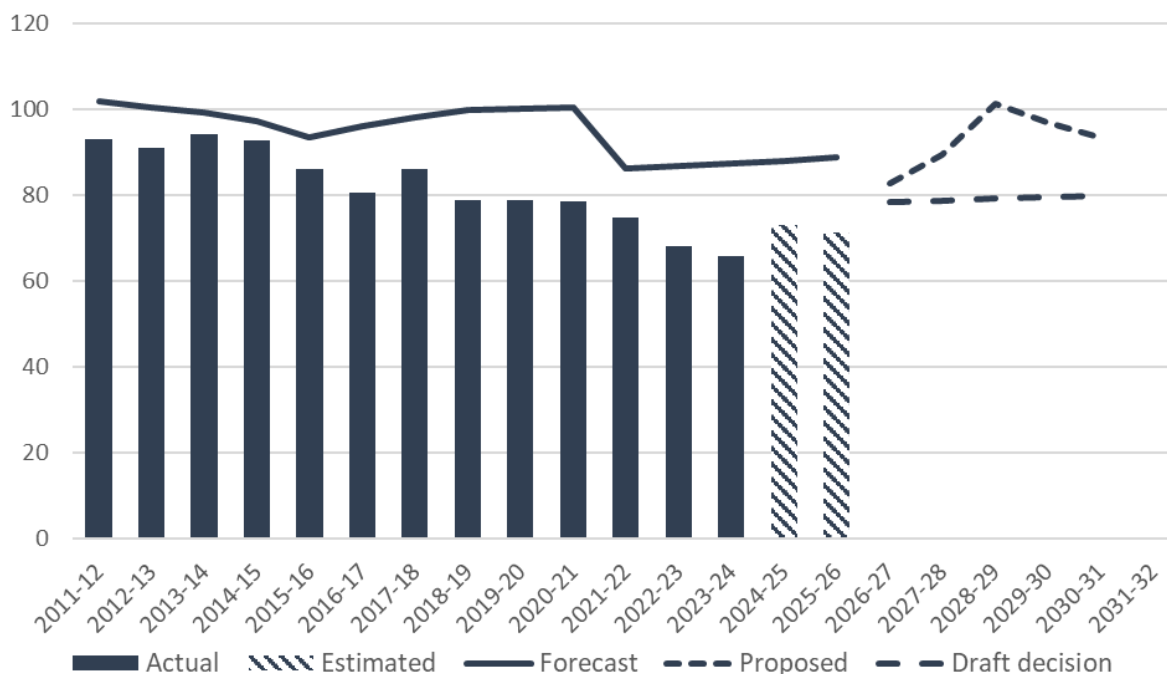
Our draft decision, which is less than AGN's proposed total opex forecast, is:

- \$41.1 million (–9.4%) lower than the opex forecast we approved for the 2021–26 period
- \$43.0 million (12.2%) higher than AGN's actual (and estimated) opex in the 2021–26 period.

⁷² RBA, *Statement on Monetary Policy – Appendix: Forecast*, August 2025.

In Figure 10, we compare our alternative estimate of opex to AGN’s proposal for the 2026–31 period. We also show the forecasts we approved for the last 2 access arrangement periods, and AGN’s actual and estimated opex over these periods.

Figure 10 Historical and forecast opex (\$million, 2025–26)



Source: AGN, *Regulatory accounts*, 2011 to 2026; AGN, *2026–31 Access arrangement proposal – Appendix 4.1 – Opex model*, June 2025; AGN, *Access arrangement, PTRM (multiple periods: 2011–16, 2016–21, 2021–26)*; AER analysis.

Note: Includes debt raising costs and movements in provisions.

We discuss the reasons for our alternative estimate of total opex forecast in more detail in Attachment 4.

3.6 Revenue adjustments

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

3.6.1 Capital Expenditure Sharing Scheme (CESS)

We have included a positive adjustment of \$17.4 million under the CESS. Our decision is broadly consistent with AGN’s proposal of \$17.5 million, as we have only updated inputs such as CPI and the weighted average cost of capital. The draft decision requires AGN to include our updated inputs in its revised proposal.

For the CESS to apply in the 2026–31 period, we consider AGN should include the following in its revised proposal:

- the tiered sharing factor as described in our updated CESS guidelines⁷³
- the ability to propose to vary its CESS reward (or penalty) to voluntarily reduce its CESS reward (or increase its CESS penalty), as this may directly benefit consumers as described in our updated CESS guidelines⁷⁴
- updated asset performance index targets for the 2026–31 access arrangement period.

This is further discussed in Attachment 6 of this draft decision.

3.6.2 Efficiency Carryover Mechanism (ECM)

We have included carryover amounts totalling –\$8.9 million (\$2025–26), from the application of the ECM in the 2021–26 access arrangement period. This is \$0.4 million higher than AGN’s proposal of –\$9.3 million,⁷⁵ because we have excluded ancillary reference services expenditure for 2019–20 and 2020–21, and made adjustments to account for recent updates to actual and forecast inflation. The draft decision requires AGN to include our updated inputs in its revised proposal. We discuss this further in Attachment 7.

We have also approved AGN’s proposal that we continue to apply the ECM in the 2026–31 period, subject to the revisions we discuss in Attachment 7.

3.7 Corporate income tax

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

Our draft decision determines an estimated cost of corporate income tax amount of zero for AGN over the 2026–31 period, consistent with AGN’s proposal. This is because we expect AGN to incur a forecast tax loss in each year of the 2026–31 period.⁷⁶ We have determined that \$278.5 million in tax losses as at 30 June 2031 will be carried forward to the 2031–36 period where it can be used to offset future tax liabilities. The forecast tax loss arises mainly because of the carry forward of AGN’s accumulated tax losses at 30 June 2026.

The reasons for our draft decision on AGN’s corporate income tax are discussed in Attachment 1 of this draft decision.

⁷³ AER, *AER Capital Expenditure Incentive Guidelines - August 2025 (Clean)*, August 2025, pp. 4–5.

⁷⁴ AER, *AER Capital Expenditure Incentive Guidelines - August 2025 (Clean)*, August 2025, p. 6.

⁷⁵ AGN SA, *2026–31 Final Plan*, 01 July 2025, p. 123.

⁷⁶ A forecast tax loss occurs when the forecast taxable income is lower than the forecast tax expense. In this event no tax is payable. Any residual amount of tax loss will be carried forward over to access arrangement periods to offset future taxable income until the tax loss is fully exhausted.

4 Forecast demand

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

- demand is an input into the derivation of AGN's reference tariffs in its access arrangement. In simple terms, tariffs are determined by dividing cost (forecast revenue) by total demand. This means that a decrease in forecast demand leads to an increase in tariffs, and vice versa.
- forecast demand is also a driver of opex and capex (new connections), which inform our decision on the total revenue requirement.

The NGR require forecasts and estimates (including the demand forecast) to be arrived at on a reasonable basis and to represent the best forecast or estimate possible in the circumstances.⁷⁷

Our draft decision does not accept AGN's demand forecast, though we have used it as a placeholder for our draft decision. At a high level we consider it is reasonable. However, as already noted, we would expect AGN to incorporate the effect of the AEMC's Connection rule change into its revised proposal.⁷⁸

The most significant impact of the rule change on AGN's revised proposal will likely relate to its proposed connections capex. However, we note AGN may also update its forecast for the number of connections to be performed in the 2026–31 period and as a result its forecast demand.

Further, our consultant Frontier Economics identified a number of issues with the demand forecasting methodology used by AGN's consultant Core Energy. We require AGN to respond to those methodological issues with its revised proposal, including potentially by adjusting its 2026–31 demand forecast.

Core Energy's forecasting methodology incorporated:

- weather normalisation of historical demand and weather data by deriving an "effective degree day" index to remove the effect of abnormal weather conditions
- deriving annual residential consumption forecasts
- deriving annual commercial consumption forecasts.

From a top-down perspective AGN's connections and demand forecasts appear largely in line with AEMO's gas forecast. AGN is forecasting a 2.4% per year decline in demand, which falls between AEMO's current Progressive and Step Change scenarios for South Australia.

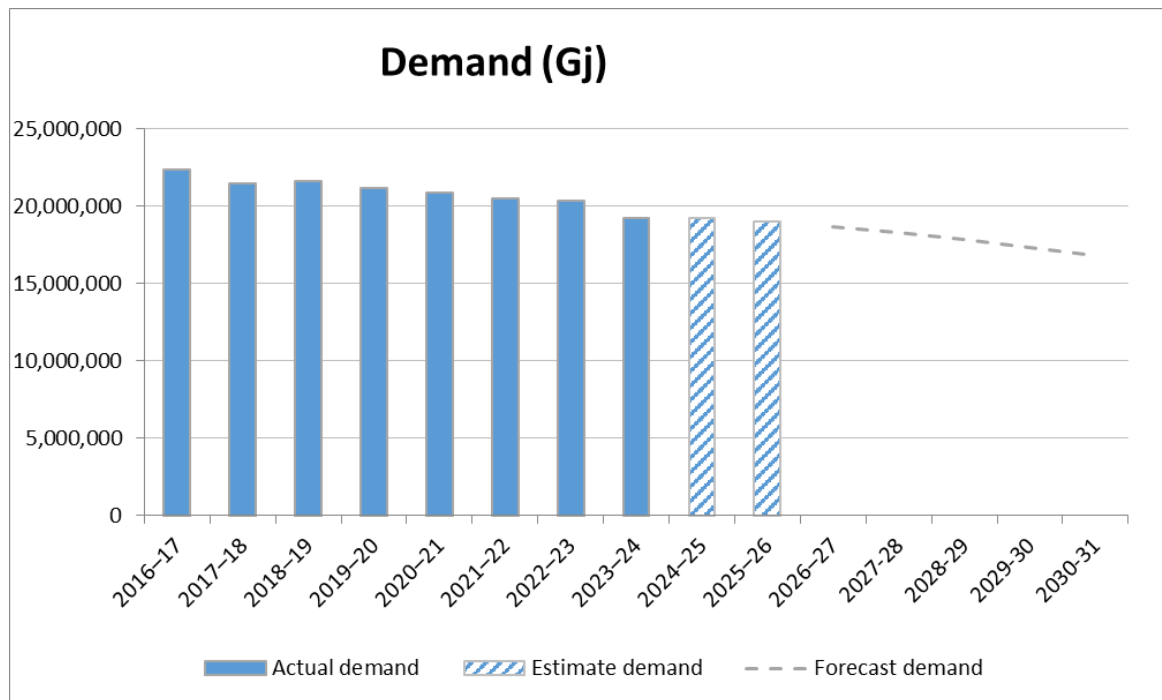
Incremental reductions in demand are driven by 5.5% per customer declines in gas consumption, driven in turn by gas appliance efficiency improvements and electrification. Per customer declines in gas consumption are partially offset by ongoing growth in customer

⁷⁷ NGR r 74.

⁷⁸ AEMC, *Draft rule determination – National Gas Amendment (Updating the regulatory framework for gas connections) Rule*, September 2025.

numbers. For example, residential development projects in South Australia are proceeding with gas connections. AGN’s forecast demand is set out in Figure 11.

Figure 11 AGN’s forecast demand



Source: AER analysis.

Frontier Economics identified the following potential flaws in Core Energy’s methodology:

- limited justification for its effective degree day methodology with alternative specifications providing better results
- problems with the determination of “average” weather and use of incorrect weather sensitivity to normalise demand
- errors in recent monthly consumption data
- assumptions for connections, disconnections and demand per connection are unsupported by analysis.

We provide a detailed discussion of each of the above issues in Attachment 4. We will publish Frontier Economics’ report so that stakeholders may see the detailed analysis underlying our draft decision.

5 Reference services and tariffs

AGN's access arrangement specifies the reference service it will provide, the tariffs for that service, and the other terms and conditions on which it will be provided.⁷⁹

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.⁸⁰

AGN proposed to maintain the same reference and non-reference services approved in our November 2024 decision on its 2026–31 reference service proposal. The proposal included haulage reference services and ancillary reference services. To inform our 2024 decision, we assessed AGN's reference service proposal against NGR requirements, including the reference service factors. We consulted publicly and received one submission, from the Essential Services Commission of South Australia, supporting AGN's reference service proposal.⁸¹

In its reference services proposal, AGN proposed and we approved an abolishment service as an ancillary reference service. AGN has not previously charged for abolishment services but instead recovered abolishment costs through its opex allowance. All other reference and non-reference services are consistent with the current period. This is discussed further in section 5.2.3.

AGN's proposed reference services are consistent with our 2024 reference service proposal decision, as required under the NGR. However, we require AGN include in its revised 2026–31 access arrangement proposal an additional full-cost abolishment service tariff for knock downs, rebuilds and renovations.

5.2 Reference tariff setting and variation mechanism

This section first discusses the tariff structures and tariff variation mechanism proposed by AGN for haulage, then for ancillary reference services, as well as covering the cost pass through mechanism.

⁷⁹ NGR, r. 48(1).

⁸⁰ NGL, Chapter 5.

⁸¹ AER, *Final decision, Australian Gas Networks (South Australia) Gas Distribution Determination 2026 to 2031 Reference service, tariff variation mechanism and tariff structure*, November 2024.

Our draft decision includes decisions on the structure and levels of AGN's reference tariffs (reference tariff setting) and the mechanism by which those tariffs can vary over the access arrangement period (reference tariff variation mechanism).

Reference tariff setting requires AGN to explain how it allocates revenues and costs between reference services and other services, and how it determines different tariffs.

AGN proposed retaining its declining block structures for its haulage tariffs with a modest flattening of the declining blocks of its volume (small) customer tariffs and a continuation of its declining block tariffs for its demand (large) customer tariffs. For its abolishment tariff, AGN proposed to partially socialise the cost across all customers, giving an abolishment tariff of \$257, with the balance of the abolishment cost allocated to opex. For the tariff variation mechanism for haulage reference services, AGN proposed a preferred weighted average price cap tariff variation mechanism and a secondary hybrid tariff variation mechanism with revenue sharing bands of 10%.

5.2.1 Haulage reference services – tariff structures

Under AGN's declining block structures for haulage tariffs, per unit charges decline as increasing volumes of gas are consumed. We consider this tariff structure promotes the use of gas, in conflict with the emissions reduction aspect of the NGO. One available reform is to equalise, or flatten, 2 or more blocks of the existing tariff structure, to establish consistent per unit charges for gas regardless of the volume consumed and to reduce the implicit reward for higher gas consumption.

Our draft decision is to not accept AGN's proposed tariff structures for gas transportation. The draft decision requires AGN flatten its volume (small) customer tariffs further in its revised proposal, by retaining a fixed charge and a block 1, but amending subsequent blocks to a single flattened block 2. For its demand (large) customer tariffs, our draft decision requires that AGN in its revised proposal consider transitioning (along similar lines to the volume (small) customer tariffs), away from its declining block tariff structures during the 2026–31 period.

We consider the first price block of AGN's existing tariff structures could be retained and priced high relative to the remainder of the tariff structure. This reflects that gas network costs are largely sunk, not varying with the volume of gas consumed. As all customers face the first price block, we consider recovering more network revenue from that block compared to others is reasonable and reflects an economically efficient pricing structure. It is the subsequent price blocks that should be equalised to, in-effect, establish a two-block tariff structure.

We consider the rebalancing across tariff blocks proposed by AGN is not clearly explained or sufficient to achieve flatter gas transportation tariffs. For AGN's revised proposal we require modelling of customer impacts for a volume tariff with blocks 2, 3 and 4 flattened (equalised). Impact modelling should encompass the annual impacts if AGN seeks to transition to the flattened structure over the 5-year 2026–31 period. Impact modelling should cover at least disaggregation into differing consumption levels and identify the number of customers at each consumption level.

5.2.2 Haulage reference service – tariff variation mechanism

Our draft decision is to not accept AGN's proposed weighted average price cap tariff variation mechanism for its gas transportation reference service. We largely accept AGN's secondary proposal, a hybrid tariff variation mechanism, but we require that the proposed revenue sharing thresholds be adjusted to 5% (from the proposed 10%).

While we acknowledge AGN's position its stakeholders have expressed a preference for ongoing weighted average price cap regulation, we also note CCP33's comments that AGN's stakeholder engagement could have been clearer about the options and associated impacts.

We consider a hybrid tariff variation mechanism, incorporating elements of both price cap and revenue cap regulation, better reflects the changed regulatory context for provision of gas haulage services. A hybrid tariff variation mechanism reduces the incentive to grow gas demand (better aligning with emissions reduction objectives than a price cap), while mitigating potential tariff year-on-year volatility (which can be a feature of revenue cap regulation).

On the details of AGN's proposed hybrid tariff variation mechanism, we consider AGN's proposed 10% revenue sharing thresholds are too broad and it is unlikely that demand will fall outside the 10% band. This means a hybrid mechanism with 10% bands would essentially be the same as the status quo of price cap regulation and would not alleviate the inherent incentive for AGN to grow demand. Our draft decision is that AGN's hybrid mechanism must incorporate 5% revenue sharing thresholds, consistent with the tariff variation mechanism proposed to us by Jemena Gas Networks for its 2025–30 access arrangement.

5.2.3 Ancillary reference services – tariff structures

Our draft decision is to approve most of AGN's proposed ancillary reference tariffs. However, we consider there are issues with its proposed tariff for small customer abolishment.

First, we note our approach to establish partially socialised abolishment tariffs for New South Wales (2025–30) and Victoria (2023–28) was premised on written advice from jurisdictional safety/technical regulators that high abolishment tariffs disincentivise customers from requesting the abolishment service. Without other risk mitigations available, those specialist regulators were concerned that high abolishment tariffs would leave an unacceptably large number of unused (dormant) gas connections in situ for indefinite periods with commensurate safety risks. We responded to their written advice by setting New South Wales and Victorian abolishment tariffs at a fraction of the full cost of performing the abolishment service, with the balance to be recovered via haulage tariffs faced by all gas customers (i.e. socialised).

Similarly, our draft decision on Evoenergy's 2026–31 proposal, released at the same time as this AGN draft decision, relies on written advice from the ACT Utilities Technical Regulator. In the Evoenergy case, our draft decision is to approve a fully priced abolishment tariff on the basis the ACT Government will mandate abolishment of dormant gas connections when the customer's property is sold – mitigating the most significant risk identified by As Low As

Reasonably Practicable risk assessments.⁸² In that policy context, the Utilities Technical Regulator confirmed the Evoenergy / ACT approach of facilitating large numbers of dormant connections is reasonable, leading to our draft decision to approve Evoenergy’s fully priced abolishment tariff.

For South Australia, we have not received a submission from the South Australian Office of the Technical Regulator on AGN’s proposed partially socialised abolishment tariff. While our draft decision is to approve AGN’s proposed \$257 abolishment tariff, this can only be a placeholder for our final decision. We would welcome advice by the Office of the Technical Regulator on this point. In the absence of such advice, we may change our approach with our final decision.

On the level of AGN’s partially socialised abolishment tariff, and subject to the views of the Office of the Technical Regulator, we consider it is reasonable. The non-socialised portion of \$257 benchmarks reasonably against the \$220 that we approved for Victoria and \$250 for New South Wales.

On AGN’s proposed total cost of \$1,250 for small customer abolishment, we consider it too high and out of step with other distributors. We consider a reduction of 20% is appropriate to lower the price to a benchmarked \$1,000.

Our draft decision also requires AGN to include in its revised proposal a full-cost abolishment tariff of \$1,000 for customer planning knock down rebuilds and renovations of their property. This will mitigate socialised costs to be recovered from all gas customers.

We are satisfied that AGN’s proposed tariffs for its remaining ancillary reference services are reasonable.

5.2.4 Ancillary reference service – tariff variation mechanism

Our draft decision accepts AGN’s proposal to escalate ancillary reference tariffs annually by CPI. This keeps prices constant in real terms and is consistent with current practice for other gas distributors.

5.2.5 Cost pass through mechanism

We accept the nominated cost pass through events proposed by AGN for the 2026–31 period, subject to minor changes in wording to align with our recent determinations. The approved events also applied in the 2021–26 period. These events are:

- regulatory change event
- service standard event
- tax change event
- terrorism event
- insurer credit risk event

⁸² As Low As Reasonably Practicable risk assessments undertaken for Victoria and the ACT have separately identified new owners of a property with fully electrified appliances but a live gas connection as creating the largest risk of inadvertent strikes on gas pipes.

- insurance coverage event
- natural disaster event.

We have replaced the insurance cap event with the insurance coverage event to align with our recent decisions.

5.3 Non-tariff components

In addition to its total revenue requirement, demand forecast and resultant tariffs, our decision on AGN's proposed access arrangement includes an assessment of a range of non-tariff components that go to the commercial relationships between AGN and its retailers and other network users.

AGN state it has not made material changes to its terms and conditions and its access arrangement reflects previous AER decisions, as well as engagement with its stakeholders over many years.⁸³

AGN proposed a number of amendments to its access arrangements, and considers the changes are not substantive and reflect general updates or alignment with the NGR, incorporation of feedback from its RRG. AGN indicate the main change of its terms and conditions is in response to new laws introduced to further regulate unfair contract terms in small business contracts under the Australian Consumer Law.⁸⁴

AGN has engaged with its users on its revisions and state that no significant stakeholder feedback has been received. We consider the approach appears to be reasonable from AGN but would encourage it to continue engaging with stakeholders on elements of its terms and conditions for its revised proposal.

Our draft decision approves the proposed non-tariff components of AGN's access arrangement for the 2025–30 period. Attachment 5 sets out our draft decision in further detail.

⁸³ AGN, *2026–31 Final Plan*, July 2025, pp. 151-152.

⁸⁴ AGN, *Attachment 15.1 Consultation on the Terms and Conditions*, July 2025, p. 2.

List of submissions

We received 5 submissions in response AGN's proposal.⁸⁵

Table 6 Submissions received on AGN's proposal

Submission
Energy Consumers Australia
Energy & Water Ombudsman South Australia
CCP33
South Australia Council of Social Services
South Australia Reference Group

⁸⁵ Submission are available [on the AER website](#).

Glossary

Term	Definition
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AGIG	Australian Gas Infrastructure Group
AER	Australian Energy Regulator
AGN	Australian Gas Networks Limited (SA)
APA	Australian Pipeline Limited
capex	capital expenditure
CCP33	Consumer Challenge Panel, sub-panel 33
CESS	Capital Expenditure Sharing Scheme
CPI	consumer price index
ECA	Energy Consumers Australia
ECM	Efficiency Mechanism Carryover
ICT	information and communication technology
NGO	National Gas Objective
NGL	National Gas Law
NGR	National Gas Rules
opex	operating expenditure
PTRM	Post tax revenue model
RAB	regulated asset base
RBA	Reserve Bank of Australia
RFM	roll forward model
RORI	Rate of Return Instrument
RRG	Retailer Reference Group
SACOSS	South Australian Council of Social Service
SARG	South Australian Reference Group
MP	Statement on Monetary Policy
WACC	weighted average cost of capital