AGN Revised Final Plan for South Australian Gas Network July 2026 – June 2031

Submission from the South Australian Reference Group Review Panel

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1. Summary and Conclusions

Introduction

The Australian Gas Networks (AGN) gas network in South Australia is subject to full price regulation by the Australian Energy Regulator (AER). This means that every five years AGN submits an 'Access Arrangement' to the AER setting out:

- The services offered on the network,
- The price paid for those services, and
- The non-price terms under which access to the network will be provided

over a future five year period. AGN's next period is 1st July 2026 to 30th June 2031. The AER assesses the AA with reference to the National Gas Objective[1] and a 'propose/respond' process whereby the network proposes and the AER responds in a structured timetable. AGN is now at the final stage of this process. The AER delivered its Draft Decision in November 2025 and AGN has responded with its Revised Final Plan in January 2026. All that remains is for the AER to deliver its Final Decision due by mid-May.

Central to this AER process is consumer and stakeholder engagement. A key part of this consumer engagement has been AGN's establishment of the South Australian Reference Group (SARG). Membership of the SARG reflects the diversity of the AGN's customer base with organisations representing residential and business customers, major gas users, customers facing vulnerability, multicultural communities, the building industry, property developers and the Ombudsman. Under the Terms of Reference[2] the SARG has been established:

> "… to provide independent and constructive feedback and challenge based on their expertise and insight during the development of AGN SA's 2026-31 regulatory proposal which include a review of:
>
> - AGN's engagement program and associated activities, and
> - AGN's regulatory proposal (Draft and Final Plans)."

In December 2024 the SARG decided to establish a SARG Review Panel, consisting of three SARG members, to engage more deeply on the AA process and prepare submissions to AGN and the AER[3].

This submission, which comments on both the Draft Decision and Revised Final Plan, is the third submission the SARG Review Panel. All submissions reflect feedback on behalf of the SARG, not on behalf of the individual constituencies of Review Panel members. A summary of the conclusions in this submission was discussed in a meeting with SARG members in early February. This submission has been discussed with the SARG and reflects the views of the full SARG except for the conclusion to support the proposed $70m accelerated depreciation (AD).

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[1] "to promote efficient investment in, and efficient operation and use of, electricity/gas services for the long term interests of consumers of electricity with respect to:

a. price, quality, safety, reliability and security of supply of electricity; and
b. the reliability, safety and security of the national electricity system; and
c. the achievement of targets set by a participating jurisdiction—
    i. for reducing Australia's greenhouse gas emissions; or
    ii. that are likely to contribute to reducing Australia's greenhouse gas emissions."

[2] See https://gasmatters.agig.com.au/australian-gas-networks-south-australia-access-arrangement-2026-27-2030-31

[3] The Review Panel now has two members following the resignation of one member to take up a new role.

The organisations that two SARG members represent will be making individual submissions on that issue. The differing view are respected by all SARG members.'

We note the language that AGN has used to name its key documents during the development of their Access Arrangement (AA) proposal for July 2026 to June 2031 as their language is not standard:

1. Draft Plan (DP), released in March 2025
2. Final Plan (FP), lodged with the AER in July 2025. This is the actual Access Arrangement proposal as required under the national rules and referred to by the AER as "The Proposal"
3. Revised Final Plan (RFP) lodged with the AER in January 2026 responding to the AER's Draft Decision released in November 2025) and referred to by the AER as the Revised Regulatory Proposal.

We use the shorthand 'AA, 'DP', 'FP', 'RFP' and 'AD' in this submission. We use the shorthand 'DD" for the AER's Draft Decision. All dollars are $2025-26.

We would like to take this opportunity to sincerely thank AGN, fellow SARG members and AER staff for their support and engagement during this AA process.

<u>Panel Conclusions</u>

The main issue through this process whether there is a 'future for gas' under the National Gas Objective and Government energy and emissions policy and, if so, how long? Phasing out the use of natural gas has implications for recovery of the costs of long lived gas network assets that have a life beyond when Government policy may seek to end the use of natural gas. How should the costs of stranded network assets from transitioning to the net zero future be divided between todays and tomorrows customers and between customers (todays and tomorrows), network owners and Governments.

In our submission on the Draft Plan, we highlighted the 'missing chapter' on the 'future of gas'. This would provide more detail on how AGN understand its vision, how it would be achieved, what needs to occur in 2026-31 and the risks to that occurring. This was necessary to understand their approach to accelerated depreciation (AD) (AGN use the term 'additional depreciation') which is one way to allocate costs between consumers and network owners.

Considerable information on the 'missing chapter' was provided in the FP that argued for a renewable gas future for the AGN network. AGN's modelling concluded that the optimal level of AD in 2026-31 was ~$70m. This was reduced back to $30m to produce a price path over 2026-31 of no real increase and align with the AER's approach as it had been developing with the Victorian networks for 2023-28 and Jemena NSW for 2025-30 of pricing 'guardrails'.

In our submission on the FP, we did not share AGN's confidence on a renewable gas future. We cited the many hydrogen projects that were being closed down supporting our view that a renewable gas future in South Australia was not currently viable and is very unlikely to be viable in the long term. This led to us suggesting a higher level than $30m is likely to produce greater intergenerational equity – it is equitable for today's customers to pay a larger share of the long lived assets they were using before they leave the system to electrify. This would reduce the burden on the remaining customers in the 2030s and 2040s who are more likely to be unable to electrify eg for residential and commercial too expensive or renting and for industrial – not technically possible or commercial. These issues are complex and we noted that while customers wanted to maintain a choice between gas and electricity as affordable options, the implications of this choice were not well understood.

The DD did not allow any AD given the AER's conclusion of a supportive SA Government policy towards renewable gas and the AER's approach to determining asset stranding. It also did not accept the proposed opex and capex expenditure and the tariff structure requesting more information to justify prudency and efficiency of proposed expenditure and that AGN undertake further engagement on AD and tariff structures.

The RFP provides the results of this engagement as well as information to justify their expenditure proposal. Given a combination of the move away from supportive SA Government policy and the AER's approach to AD in its draft decision on the Evoenergy gas network, the AD ask was increased to $70m.

In summary we make the following comments and recommendations on the DD and RFP:

Engagement	• Given the very tight timeframe, AGN undertook quality engagement on AD and tariff structures in preparing the RFP • The results can be relied upon by the AER in assessing consumer views on these issues
Future of gas	• Support the AGN proposal for $70m AD • Recommend the AER provide more explicit guidance and analysis in the Final Decision on how it assesses proposals for AD including providing more analysis and transparency around how it makes its 'judgements' eg pricing guardrails, when assessing the level of AD • Urge AGN to continue exploring 'future of gas' issues with the SARG
Opex	• Support a prudent and efficient step change for cyber security • Support AGN's approach to abolishment of redundant sites where required for safety reasons • Support AGN's approach to estimating Unaccounted for Gas costs • Recommend the AER provide more explicit guidance on what is meant by a 'material' step change in gas networks with a declining trend component
Capex	• While the AER has approved the $8m renewable gas readiness capex, we continue with our position in earlier submissions to not support it; if AGN wishes to spend these fund then it should be included as speculative capex under rule 84 • Support AGN's approach to cyber security • Recommend the AER closely examine the prudency and efficiency of the revised IT transition cost, including a reduced risk allowance
Demand	• Given the level of uncertainty around demand forecasts we hope that the current AEMC review of the gas regulation framework examines options to reduce the level uncertainty and impact on consumer bills.

Revenue and prices	• Support AGN's proposed changes in residential and small business tariffs which accurately reflect customer engagement • Support AGN's approach to not change large customer tariffs • Given flatter tariffs have both winners (bill goes down) and losers (bill goes up), recommend that the AER provide more evidence in the Final Decision for the emission reduction benefits of flatter tariffs – not only that they result in emissions reductions but these reductions are achieved efficiently eg through a marginal cost of abatement analysis • Support AGN's approach to having full cost recovery for abolishment no matter the reason

2. The Future of Gas

This is the most significant and contentious issue in the reset. Its complexity makes it difficult for all parties – AGN to decide what future it has and how it can engage with its customers with its affordability impacts; consumer advocates seeking to balance the interests of different consumer classes today and intergenerational equity for today's vs future consumers; and the AER as it seeks to balance all these issues within the rules. These rules are currently undergoing a major review by the AEMC with decisions on full cost connections and abolishments the start of more fundamental consideration of the regulatory framework with the results coming after the AGN reset is completed.

AER Draft Decision

The AER rejected the proposed $30m AD because[4]:

> "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 AD. 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 AD is consistent with our capex decision, which accepts AGN's growth and renewable readiness capex."

So, a combination of acceptance of renewable gas readiness and mains augmentation growth capex, AGN's renewable gas vision and supportive SA Government policy leading to little or no risk of economic asset stranding.

What AGN is proposing in the Revised Final Plan?

AGN is proposing 'additional' depreciation $70m, based on their modelling presented in the FP and a comparison of the Jemena (NSW) and AGN (South Australia) policy contexts. It is based on three main factors:

- Change in SA Government policy to be less supportive of renewable gas than previously and less supportive than NSW – the AER approved $115m AD for Jemena in 2025-30,

[4] See p.4 https://www.aer.gov.au/documents/aer-draft-decision-agn-sa-access-arrangement-2026-31-overview-november-2025

- The absence of the renewable gas certificate scheme plus large reduction in connections capes means real price path over 2026-31 is half what the AER approved for Jemena, and
- The AER's evolving approach to depreciation as shown in its draft decision on Evoenergy's ACT gas network; that decision increases the risk of asset stranding with the network not being able to recover its efficiently incurred capex even in a jurisdiction where there is a hard closing date for the network, a government policy that does not support renewable gas and a ban on new connections.

Government policy in South Australia vs NSW

In the DD, the AER argues that because the SA policy settings are more supportive of gas networks than in NSW and the ACT, there is no need for AD. AGN presents a detailed analysis of gas policy in the two jurisdictions concluding that[5]:

> "…both jurisdictions maintain broadly aligned, technology neutral approaches to the energy transition. A key distinction is that NSW is the only state in Australia that has implemented a tangible policy mechanisms to support renewable gas…While SA has been a longstanding leader in hydrogen, there are no direct funding programs, network concessions or demand-based mechanism in place or announced as under development."

In its 2025-30 AA proposal, Jemena proposed 8 biomethane projects totalling 6.7PJ supply. In SA there is currently only one biomethane facility, to be connected in April 2026 for an annual capacity of 210TJ. The AER allowed Jemena $115m in AD - 3% of RAB. The equivalent for AGN would be $62m.

AD and growth capex

The level of growth capex is substantially lower than in the FP because of full cost recovery from new connections. Apart from the connections cost before the 1 October 2026 introduction of full cost connections, AGN has two components of what could be considered 'growth' capex – connection capex incurred prior to 1st October 2026 ($9.3m)and the Concordia trunk main ($5m) which total 4% of proposed capex.

The AER seems to be arguing that:

- there is a choice – accept new customers or reduce risk by increasing depreciation
- a network cannot have AD until it stops adding new customers

The problem with that approach is that additional customers lower the bills for existing customers and AGN might only have around 15 years (the life of gas appliances) to recover its capex which will be impossible given the price impact. Yet the AER allowed the $115m AD for Jemena when it was proposing 1.4% growth in customer numbers (AGN is 0.7%) and the costs of those connections was going into the RAB.

[5] See p. 16 https://www.aer.gov.au/documents/agn-sa-attachment-65-response-draft-decision-depreciation-january-2026

The AER's 'real price path' approach

The AER's approach is to first decide if AD should be allowed given the jurisdictional gas policy. If yes, set the level as a goal seek based on a judgement call on the constraints the jurisdictional policy places on gas consumption.

Decision	Accelerated depreciation?	Guardrail annual real price path goal seek over 5 years
Victoria - 2023-28	Yes	1.5%
Jenema NSW 2025-30	Yes	0.5%
Evoenergy ACT 2026-31 DD	Yes	1.5%[6]
AGN SA	No	NA

The AER argues that its approach[7]:

> "... manages risk of triggering a rush of customers (including vulnerable customers0 with the burden of high power unit network costs, and place increasing pressure on the existing network and supply"

AGN responds by saying that the selection of the guardrails[8]:

> "...must be backed by robust and transparent evidence and reasoning to promote stakeholder confidence."

which does not seem to currently be the case. The AER's modelling involves demand being exogenously determined outside of the PTRM. These demand forecasts do not seem to take account of demand elasticities to give an idea of what guardrail level might be possible without triggering a 'rush'[9]. .

Is there ever a window for AD?

AGN comments[10]:

> "A simple reading of the AGN SA and Evoenergy Draft Decisions together suggests that the AER considers it too soon to do anything the case of AGN SA, and too late to do anything substantive to deal with stranding risk in the case of Evoenergy. This raises the question of where the AER considers that the "window" for action in respect of depreciation lies."

It is unclear under what circumstances would the AER 'open the window' for AD. Even if the window is open, the range of recent network decisions means there are no clear guidelines on 'how wide' it would be opened. For example, following the Crew and Kleindorfer approach, how do consumers have confidence that the AER is not 'penny-wise, pound-foolish' by limited early

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[6] This was reported as 4% in the draft decision but AGN claims that discussions with Evoenergy meant that stripping out the impact of jurisdictional schemes cost pass through bring the actual guardrail back to 1.5%.

[7] See p. 7 https://www.aemc.gov.au/sites/default/files/2025-11/19._aer_-_grc0082_cp_submission.pdf

[8] See p. 35 https://www.aer.gov.au/documents/agn-sa-attachment-65-response-draft-decision-depreciation-january-2026

[9] We discuss this in Section 6 below.

[10] See p. 38 https://www.aer.gov.au/documents/agn-sa-attachment-65-response-draft-decision-depreciation-january-2026

AD in the name of short term affordability which does not fully account to the long-term interests of consumers?

How does the AER interpret the 'regulatory compact'

Under the rules (section 24(2)) a gas network is provided with a '…reasonable opportunity to recover at least the efficient cost the service provider incurs'. The AER says that this is not a guarantee and AGN agrees – the world changes over the life of long lived assets. However the Evoenergy draft decision suggests that the AER is limiting a network's ability to have a 'reasonably opportunity' to recover its efficiently incurred capex. This is a change from the view expressed by regulators when the gas market rules were established with evidence provided in the Incenta experts report[11].

Even though there is an explicit ACT Government policy to close the gas network in 2045, Evo's request to cap asset lives at 2045 was rejected with the AER. The AER put in place asset lives that extend to 2050 for MP pipes and 2055 for HP pipes because, while high, there is not a 100% chance of the gas network closing in 2045[12]. So Evoenergy effectively requires a change in Government policy to have a 'reasonable opportunity' to recover its efficient capex.

Panel Comments on the Draft Decision and Revised Final Plan

In our submission on the FP we greatly appreciated the significant additional information provided by AGN on its vision for a pathway to 2050 and the risks of this pathway and what does it mean for the 2026-31. Nevertheless, we came to a different conclusion on the first, which means we had a different view on the second.

- We did not see a pathway to competitive renewable gas (hydrogen and/or biomethane) supply in sufficient volumes in a distribution network to enable a viable network to exist in 2050; despite initial grand visions, hope from some and ebullient press releases and Government reports, multiple hydrogen projects have been cancelled; we saw electricity has a much higher chance of becoming the preferred customer choice for most customers well before 2050
- Given these risks for a renewable gas future, the $70m AD suggested by AGN's modelling for 2026-31, or the $30m they proposed, was likely too low, though AEMC approval of full cost connection charges would lessen our concern
- The AER's price cap of 0.5%/yr real applied in the Jemena decision has little impact on affordability and a higher cap is a reasonable balance between intergenerational equity and current affordability; movements in the commodity component of the delivered gas price will be much more important to consumer choice and affordability.

Developments since this submission have only confirmed our pessimism on AGN's vision:

- SA Government policy continues to pivot to a focus on ensuring the Whyalla steel works survives, with diminished current interest in a green steel future based on hydrogen; a recent State Auditor General's report said that $285m had been spent by the State

[11] https://www.aer.gov.au/documents/agn-sa-attachment-66-response-draft-decision-depreciation-incenta-expert-report-january-2026

[12] See pp 15-18 https://www.aer.gov.au/documents/aer-draft-decision-evoenergy-access-arrangement-2026-31-attachment-1-capital-base-regulatory-depreciation-and-corporate-income-tax-november-2025

Government in the three years up to 2024-25 on its proposed hydrogen plant at Whyalla with the State Government hoping to recoup some of the cost by selling the turbines slated for the hydrogen power plant[13]

- the State Government did not support a renewable gas certificate scheme and this opex step change was withdrawn with HyP Adelaide project put off beyond the 2026-31 period; the Government's priority is to ensure there is enough competitive gas for gas fired generation
- AEMC connections charge – removes $109.5m from RAB so effectively higher AD

Hydrogen projects around the world continue to stall with one major bank referring to the industry as projects that are 'stuck in the pilot stage'[14] as it remains high cost with low offtake. Large scale commercial projects might be possible in China, but they have a much lower cost structure and level of Government subsidy than Australia[15].

AGN has recognised these changes – a 'business is changing' RFP replaces a 'business as usual' FP - as well as the AER's evolving approach to AD seen in the Evoenergy draft decision combined to result in the $70m AD.

We observe a lot of 'judgement' in how the AER came to is DD decision when more detailed analysis would be helpful to consumers

AER's AGN and Evoenergy draft decisions frequently refer to 'judgement' calls underpinning the decisions rather than detailed analysis. We agree with AGN's conclusion that the AER's analysis should be backed by more robust and transparent evidence to promote consumer confidence in their decision.

The real price growth guard rails

As noted above, our submission on the FP[16] suggested that the AER's approach of using a real price escalator as a 'guardrail' to balance current and future consumers affordability and meet the emissions objective in the NGO has its limitations. The difference between a 1.5% real increase and say a 2.5% real increase for a residential customer was only $28 on the average annual bill of $1,120. And this assumes the retailer does pass on the tariff change which is not always the case. Other factors beyond the control of the customer, network or AER eg WACC, expected inflation and commodity component can have a much larger impact on the delivered price.

We are not necessarily opposed to a guardrail. We support AGN's view that selection needs to be underpinned by more robust and transparent evidence rather than simply 'judgement'. It seems the AER is setting up a 'strawperson' argument that misses the point. In the Evo draft decision they say[17]:

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13 https://www.abc.net.au/news/2025-10-21/sa-government-confident-of-recouping-hydrogen-power-plant-costs/105910680

14 https://think.ing.com/articles/energy-hydrogen-stuck-in-the-pilot-phase/

15 https://www.hydrogeninsight.com/production/china-approves-41-clean-hydrogen-projects-that-will-be-eligible-for-state-support/2-1-1914897

16 See pp 19-20 https://www.aer.gov.au/system/files/2025-08/SARG%20Review%20Panel%20-%20Submission%20on%20AGN%28SA%29%20-%202026-31%20Access%20Arrangement%20Proposal%20-%20August%202025.pdf

17 See p. 14 https://www.aer.gov.au/documents/aer-draft-decision-evoenergy-access-arrangement-2026-31-attachment-1-capital-base-regulatory-depreciation-and-corporate-income-tax-november-2025

> "However, any amount of AD must be balanced against price impacts and affordability. There is a real risk that adopting a policy of accelerating depreciation, without clearly defined limits, would be likely to result in large and repeated increases in future gas prices. This would not align with the long-term interests of customers, as it risks the use of the network (including the number of customers) to decline faster than anticipated, which further increases the risk of asset stranding and of costs being borne by an even smaller number of customers in the future."

This still leaves the need to provide more analysis about the level of the guardrail the AER chooses:

- why say 1-1.5% guardrail that might be in the interests of consumers in the next AA period, is assessed from the perspective of the *long term* interests of consumers who are, for various reasons, still around in the mid-2030s paying much higher tariffs because of the 1-1.5% in 2026-31when customer numbers and consumption were much higher?
- why should it be set in a way that may preclude the ability of a network to have a 'reasonable opportunity' to recover its efficiently incurred capex?
- what risks it might have to the long term network revenue required to support continued capex and opex to meet its service obligations to the remaining customers?

What elasticities (straight and cross) has the AER used to come to their conclusion on what 'triggers a rush'? What is the evidence to support those variables – apart from 'regulatory judgement'? While we still see an important role for this judgement, as the AER does regularly in assessing network expenditure proposals, consumers like to see evidence of prudency and efficiency to underpin that judgement. The AGN consumer choice model is one approach. The AER may have another.

It is difficult for a well-informed consumer group, let alone consumers more generally to understand the AER's explanation of asset stranding and its implications for AGN

The AER's argument for rejecting any AD is[18]:

> "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. 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 AD 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 AD. 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."

The AER's Regulating gas pipelines under uncertainty information paper[19] concludes:

[18] Op cit p. viii
[19] See pp 25-6 https://www.aer.gov.au/system/files/AER%20Information%20Paper%20-%20Regulating%20gas%20pipelines%20under%20uncertainty%20-%2015%20November%202021.pdf

> "When faced with a material stranded asset risk, network businesses may want to bring forward the cost recovery of their investments to reduce the expected losses they may face in the future."

AGN's modelling in the FP argued that, in the absence of AD, there is still economic stranding risk in their 'future of gas world' with blended hydrogen in the pipelines because of competition from electricity. Because we did not agree with that future our submission on the FP, we argued that AGN faced material economic stranded asset risk and potentially physical stranding risk if all customers leave. The RFP moves to accept the greater future economic asset stranding risk given the recent change in SA Government policy support. This is the basis for the $70m proposal.

The AER seems to equate economic stranded risk more to a form of physical stranding risk, which we do not see in their 2021 information paper. A network might continue to be used ie it is not physically stranded but not be able to price (due to competition from electricity) to recover its efficiently incurred costs. This is a case of economic asset stranding if not physical asset stranding. In the extreme, a network's pipelines can be full but there still can be a material economic stranded asset risk because competition from electricity mean the tariffs charged do not provide for full cost recovery. Asset standing is a price issue. AD is, as noted in the AER's 2021 information paper, driven by economic stranding.

The argument then becomes one of whether the economic stranding risk is material enough to justify AD. We think the modelling presented by AGN shows just that. In theory, as the Incenta report says, that is when the NPV=0 criterion is not being met and the economic value of the asset is less that the RAB. However AGN argue, and we agree, that there should be a threshold. The AGN modelling in the FP used thousands of simulations with different input process to see what was required to get a RAB value of $1b in 2050 where $1b was the value AGN thought it could get from its asset post 2050 in a competitive market with electricity. In around one third of the simulations the network fails before 2030. We think that is material and above what a reasonable threshold might be.

It seems the AER has a higher threshold when it says[20]:

> 'While AGN's modelling shows some level of stranding risk at 2050, we do not consider that its modelling provides sufficient evidence to suggest that AGN's network faces a significant stranding risk in the long term that needs to be addressed through AD in the 2026–31 period to ensure they have reasonable opportunity to recover efficient costs."

So, what should the threshold be if the risk of stranding in 34% of the simulations is not sufficient? It would be very helpful for consumers to understand how the AER would arrive at a threshold apart from 'judgement'.

The follow-on sentences to the quote above, are:

> "Instead (of AD), its modelling suggests that minimising capex is more effective in reducing stranding risk than AD. Our analysis of AGN's future of gas modelling suggests that, in most scenarios, a reduction of the forecast capex by 25–30% would allow AGN

[20] See p. 15 https://www.aer.gov.au/documents/aer-attachment-2-capital-expenditure-draft-decision-ausnet-services-distribution-determination-2026-31-september-2025

to achieve its target of $1 billion capital base value at 2050 for remaining competitive against electricity.”

Even if that reduction is a correct application of the model, we look forward to the AER explaining how AGN can prudently and efficiently operate the network in the long term given the minimal growth capex in the RFP.

The apparent inconsistency with asking for growth capex and AD

It seems that AGN cannot have both growth capex and AD – even though the AER approved both for Jemena. The AER notes in the DD[21]:

> “While AD 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.”

We think the growth capex/AD argument is considerably weakened in the RFP given the AEMC decision on new connections capex means there is now negligible growth capex. Even if you include renewable capex as ‘growth’ then it increases to just $21.3m or 6% of total capex.

Jemena AER Approved		AGN FP	AGN RFP
Growth capex	$343m	$162.3m	$14.3m
% of total capex	45%	32%	4%
		$30m	$70m
AD	$115m	$0	

Eliminating it entirely will have little impact on AGN stranded asset risk.

Concluding comments

Overall, we think that AGN’s response to the DD - the arguments set out in Attachment 6.5 supported by the Incenta expert’s report in Attachment 6.6, together with the results of the post DD consumer engagement (discussed in the next section), provide a comprehensive and well-reasoned response to the Draft Decision:

- a current comparison of SA and NSW gas policy comes to a different conclusion to the AER in the DD
- The outcome of post DD engagement supporting the $70m
- The insignificant amount of growth capex
- Our view on economic asset stranding and providing AGN with a ‘…reasonable opportunity to recover at least the efficient cost (it)… incurs’
- The AGN real price path is lower than what the AER approved for Jemena

[21] See p. 21 https://www.aer.gov.au/documents/aer-draft-decision-agn-sa-access-arrangement-2026-31-overview-november-2025

	Year 1	Year 2	Year 3	Year 4	Year 5	Annual average over 5 years
Jemena FD	+1.0%	+1.0%	+1.0%	1.0%	1.0%	+1.0%
AGN SA RFP	-1.1%	+ 1.0%	+1.0%	+1.0%	+1.0%	+0.6%
AGN Vic & Albury FD	=0.0%	+0.0%	+0.0%	+0.0%	+0.0%	+0.0%

As we noted in our submission on the FP, the current rules framework was developed with an underlying assumption that gas would be around a very long time and regulation should seek to increase asset utilisation. That context is undergoing a 180 degrees turn and the rules need to adjust to reflect that turn. The AEMC decisions on connection and abolishment charges are good first steps to making the rules more sustainable. There will be a detailed review on gas network regulation over the course of 2026 and 2027 that will require a comprehensive consumer engagement process to enable consumers to fully understand the issues and be able to make informed recommendations on future actions.

The AGN response on the future of gas provides an appropriate challenge to the AER to more fully explain and justify its approach in the Final Decision to give consumers confidence it meets the NGO. We also hope that it provides consumers with a clear view of the AER approach as they participate in the AEMC engagement.

We support AGN's proposal for $70m accelerated/additional depreciation on the basis that it improves intergenerational equity by reducing the potential for a high economic stranded asset cost on future consumers. This view also aligns with the view expressed by customers in AGN's Phase 4 workshop. We also accept that modest increase in AD now provides increased flexibility for potential new uses for the network through new business opportunities or technological breakthrough that lowers the cost of renewable gas while the network remains regulated.

Box - AEMC review of gas regulatory framework

The AEMC is currently undertaking a wide ranging review of the gas network regulatory framework. If the initial decisions on connections and abolishments are any indication, there is likely to be profound change in that framework that will have important consequences for networks and their consumers.

It is all about how the costs of the transition should be shared among consumers, networks and Governments.

Our recommendation is that the AER takes the opportunity in its Final Decision to provide consumers with more detailed and explicit guidance on is decision making process for AGN that can then be used as a guidance to consumers who wish to engage in the AEMC process. We comment on two aspects:

The share of cost between consumers and networks

The JEC rule change[22] is central to the review. It is based on a view of equity that consumers (whether rich and poor) should not pay, or at least not pay much. It seeks to shift the stranding risk to networks by replacing the concept of economic stranding with physical stranding as the criteria for AD. Networks would be restricted in their ability to claim AD for economic stranding unless the AER has undertaken an assessment to decide it was a redundant asset or anticipated redundant asset. Then the AER assess how the cost is shared between the network and its customers.

It is not clear how networks are to fund their service obligations in the face of a large reduction in revenue as customer numbers fall and consumption falls as they have lots of pipes that are half empty and which do not meet the 'redundant' definition.

This approach differs from the one we recommend in this submission.

Will Governments come to the rescue?

We don't see evidence of Governments coming to the rescue of consumers or networks. The ACT Government is half owner of the Evo gas network and it is its policy that is leading to network asset stranding and the request to the AER for AD. We can only assume from the Evo proposal that the ACT Government is not interested in having its budget bear at least some of the adjustment costs of its gas policy.

3. Consumer Engagement

We discuss how AGN responded to the Draft Decision's and SARG recommendations on further consumer engagement.

<u>AER Draft Decision</u>

When considering the Better Resets Handbook engagement components of nature, breadth and depth, and clearly evidenced impact, the AER concluded that[23]:

> "Overall, we see AGN's consumer engagement as thoughtful and well-planned."

But there were areas where there could be improvements – future of gas, AD and tariff impacts – where engagement was more inform than seeking input to help develop the proposal. While the AER acknowledged that it is difficult to engage on these complex topics, it concluded that the extent and level of collaboration was less strong that the AER had observed with other gas networks AD proposals[24]:

> "While we acknowledge the genuine commitment undertaken by AGN in developing an engagement plan to understand its customers' needs and expectations, we consider

[22] https://www.aemc.gov.au/rule-changes/gas-networks-transition-accelerated-depreciation-and-asset-redundancy

[23] See p. 10 https://www.aer.gov.au/documents/aer-draft-decision-agn-sa-access-arrangement-2026-31-overview-november-2025

[24] See p. ix https://www.aer.gov.au/documents/aer-draft-decision-agn-sa-access-arrangement-2026-31-overview-november-2025

there are areas of further consideration for AGN as it prepares its revised proposal, and for its ongoing stakeholder engagement."

The AER encouraged AGN to engage further on these issues to ensure customer preferences were reflected in the RFP.

AGN post Draft Decision engagement

The very limited time available between the publication of the DD and submission of the RFP placed a constraint on AGN's post decision engagement.

Within that constraint AGN drew on comments from the AER, the SARG and the Consumer Challenge Panel to continue its engagement with the wider SARG, the SARG Review Panel and the CCP on what it was considering including in the RFP.

There was also engagement with customers using the Deliberative Shared Value Engagement Methodology in a four hour Phase 4 customer workshop in early December 2025. There were two topics:

(i) Tariff reform in the context of the NEO emissions reduction objective and individual affordability, and
(ii) The level of AD

with a focus on impacts on different customer groups over time, rather than individual preferences alone. Participants were selected from those who participated in the Phase 3 engagement to ensure appropriate residential/business, geographic and demographic diversity. All had a reasonable knowledge base of both the engagement process and the purpose of reset engagement. Comprehensive and targeted pre-reading material was sent out to participants. The session began with an assessment of participants' understanding of the issues to be engaged on to ensure feedback was appropriately informed. Participants were asked to respond to a series of comprehension questions testing their understanding of the issues.

A central feature of engagement on the two topics was a composite fairness testing framework that surveyed participants' perceptions of fairness across a range of scenarios and stakeholder groups. AGN's aim was to deliver shared value – balancing the interests of various stakeholders including both current and future customers and AGN itself. Key insights presented in the KPMG report of the session were[25]:

- Customers seek a smooth and equitable transition and support additional depreciation today, recognising its role in the long-term interests of customers and all parties
- Customers consider it fairer to gradually, rather than rapidly, flatten tariffs, and
- Customers valued the deliberative approach for enabling informed, balanced decisions that consider shared value.

On AD, of the two scenarios presented:

1. AD Scenario 1 (the AER's proposal): $0 additional depreciation, with no adjustment to the annual share prior to the customer leaving. Bills stay the same now, but more of the network's costs remain unpaid for years.

[25] See pp 12-3 https://www.aer.gov.au/documents/agn-sa-attachment-55-response-draft-decision-agn-customer-stakeholder-engagement-phase-4-report-january-2026

2. AD Scenario 2 (alternative AGN scenario): $70 million additional depreciation, adjusting the annual share early prior to customers leaving. More deprecation is brought forward, so today's annual share increases.

participants considered that scenario 2 was fairer to pay a modest upfront increase in depreciation compared with deferral under scenario 1 and the majority (73%) saw it as a fair and reasonable balance between the interests of customers and AGN.

On tariff structure, of the two scenarios presented:

1. Tariff Scenario 1 (AGN's FP proposal): A gradual transition to flatter tariffs, involving a step-by-step move towards flatter tariffs, spread out over several years, to avoid sudden bill changes.
2. Tariff Scenario 2 (AER's Draft Decision): A rapid transition to flatter tariffs, a faster, stronger shift to flatter tariffs, where most customers pay roughly the same rate per unit of gas.

participants considered scenario 1 fair and the preferred approach. It reduced the risk of bill shock and prevented sudden spikes, offering greater stability and certainty when compared to the scenario 2.

KPMG concluded that AGN's deliberative shared value approach to engagement led to deep, high-quality participation. Customers engaged actively and thoughtfully with complex regulatory topics, demonstrating strong grasp of the issues and a commitment to fairness and shared value.

Panel comments on the Revised Final Plan

In our submission on the FP we concluded that AGN have conducted a well-planned and appropriately executed engagement program with a significant number of people involved and has pioneered an excellent online tool in Orbviz. The main challenge in this engagement, which had not occurred previously, was the substantial uncertainty regarding the future of gas and its impact on AGN and its customers. This created a level of uncertainty in how informed the view on these matters eg the technical and economic role of renewable gas, AD and tariff implications reflected informed consumer engagement outcomes, was.

The engagement with the SARG and SARG Review Panel involved detailed discussion of changes being considered for the RFP. The SARG Review Panel benefitted from many in depth discussions with AGN staff on all the matters discussed in this submission.

We observed the phase 4 engagement session on AD and tariff structure. Given the time constraint AGN was under, we found the conclusions in the KPMG report discussed above to be valid and represent the results of informed engagement. We agree with the conclusions AGN has drawn from that engagement to inform its RFP.

4. Operating Expenditure

The impact of the 'future of gas' discussion is evident with opex. Fewer customers mean lower 'trend' uplift in base opex and reduced ability of networks to gain economies of scale when they are still required to maintain a network that has increasing spare capacity. We comment on that emerging issue as well as specific step changes.

AER's Draft Decision

The AER concluded that AGN's proposal did not meet the opex criteria and substituted an alternative forecast of $396m, or 15% below AGN's proposed $464m. This reduction was driven by the AER's rejection of many step changes - renewable gas certificates, non-recurrent IT transition costs, redundant service abolishment and cyber security.

In some cases the AER indicated that its view might change with additional information and the zero allowance was a place holder awaiting that information eg AGN argued for the abolishment of redundant sites step change on the basis of the safety risk of leaving live gas assets on a property but did not provide evidence of the safety risk such as incidents that have occurred at redundant sites. Excluding the renewable gas certificates step change, which AGN withdrew prior to publication of the DD, changes the AER alternative estimate to a reduction of 9% below AGN's proposed expenditure.

The significant reduction in unaccounted for gas (UAFG) was driven by a combination of a lower demand forecast and application of a lower price drawing on ACIL Allen forecast in the 2025 GSOO. The AGN forecast was based on contracts in another jurisdiction and the AER requires a more SA specific forecast. This reduced the FP forecast of $27.9m to $14.6m.

<u>What AGN is proposing in the Revised Final Plan</u>

The table shows a summary:

Operating expenditure summary $m (2025/2026)[1]

2021 – 2026			2026 – 2031					
			FP			RFP		
AER allowance	Actual / Forecast	% chg. vs allowance	Proposal	AER DD	%chg.	Proposal	%chg. vs FP	% chg. vs DD
$439.9	$336	-24%	$464.1	$396.2	-15%	$434.0	-7%	+10%

1. Includes debt raising costs but excludes ancillary reference service

AGN have used the standard AER base, step, trend methodology with adjustments from applying later data eg actual 2024-25 costs and a revised connections forecast. Important changes are:

Trend

This is a combination of three factors – labour and materials cost escalation, output growth (customer numbers and mains length) and productivity growth. AGN take the standard approach to the first – average of AER and AGN consultant forecasts.

The output growth factor in the FP was +0.3%/yr. This has been updated to reflect the now forecast fall in customer numbers over the period following the AEMC rule change to provide for a full cost upfront connection cost to be paid by the consumer that more than offset the minor growth in mains length resulting in an annual average output growth rate of -0.4%. This reduction in customer numbers and demand has led to a revision downwards in the productivity growth factor from an annual 0.4% to zero (the same as for AGIG's Victorian gas networks for 2023-28).

Combining these revised forecasts leads to an opex trend annual rate of change of +0.2%/yr that is only positive because of labour cost increases, compared with +0.7%/yr in the FP.

Step changes

The step change of $26m for renewable gas certificates is removed due to a change in anticipated timing for implementation of the Hydrogen Park Adelaide project. The step changes for the non-recurrent IT transition ($19.1m), abolishments for safety at redundant sites and cyber security ($1.2m) have been kept – the former two based on a comprehensive analysis, the last based on the minimal 'trend' component in base opex.

Category specific charges

AGN accepts the AER volumes and provides more detailed SA specific information on the proposed price which is higher than the AER used in the DD.

Panel comments on the Revised Final Plan

Step changes

Renewable gas certificates

The Panel did not support this step change in its submission on the FP because consumers should not have to pay for AGN costs of trying to ensure the future of its asset unless it is strongly supported through informed customer engagement. The State Government has delayed its implementation of its hydrogen plan and hence consideration of who should pay for any certificate scheme to support its development is now a matter for discussion on the 2031-36 AA.

Cyber security

The Better Resets Handbook says[26]:

> "The number of forecast step changes is limited to a few well justified ones, or none at all."

For step changes like this driven by external factors outside of the business[27]:

- "It will have an impact on the costs of providing prescribed network services and it can be demonstrated that it is not capable of being managed otherwise under forecast opex, including through inbuilt provisions under output, price and productivity growth.
- Where it involves incurring costs in complex areas or markets, it is accompanied by an expert report (including analysis of options, market outlook and opinion on the reasonableness of the proposed step change).
- No double counting of costs."

While the AER was satisfied that AGN had developed a prudent and efficient plan, it argued that the cost should be absorbed in the trend component of base opex and was concerned that allowing the step change would be double counting.

The issue of the materiality of step changes and how they should be funded is a major topic in the current 2026-31 resets for Victorian electricity distributors. There the AER Draft Decisions concluded that many of the proposed step changes are not 'material' and should be financed

[26] See p. 26 https://www.aer.gov.au/documents/aer-better-resets-handbook-july-2024
[27] ibid

out of the opex trend component[28]. While no definition was provided for 'material', it appears to require a cost of >1% opex. This AGN $1.2m step change is well under 1% of total opex.

AGN draws on some of the arguments AusNet Services is using is its Revised Proposal to the AER[29] but adds the context of a gas network facing declining demand, the opposite to AusNet Services' situation. As we saw above, the trend component in the RFP is now only slightly above zero and driven by real wage forecasts.

In the past the Panel has not been supportive of small step changes arguing they should be absorbed in the trend component. This led to AGN removing a $0.3m step change for increased insurance costs. Given the revised trend component, we think there is a reasonable case for this step change to be approved given the AER's view that it is a prudent and efficient plan.

We recommend that the AER provide more explicit guidance in its Final Decision on the extent to which gas networks should be expected to absorb even small step changes when trend uplift in base opex is expected to continue to fall, possibly going negative. This may well be the case for the 2028-32 Victorian resets.

Abolishments for safety at redundant sites

We did not comment on this in our previous submissions. AGN consulted with us as part of preparing the RFP. More information has been provided on the incident risk associated with not permanently removing pipelines at redundant sites that is supported by the Office of Technical Regulator (SA OTR). While we have no expertise to assess whether the proposed amount is prudent and efficient, we do note the safety implications to customers and the wider community from not removing redundant services. The lack of a current formal obligation from the SA OTR should not be a reason to not allow the step change. AGN has an obligation to operate its network in line with AS/NZS 4645 and the SA OTR expects AGN to maintain this obligation. Further we think it is reasonable for AGN to follow what it does under Energy Safe Victoria regulation of its distribution networks in that State.

The AER highlights safety risk as a major factor in supporting socialisation of abolishment costs and highlighted the safety risk of redundant sites in their submission to the AEMC abolishments rule change[30].

Category specific forecast - UAFG

In our previous submission we left the AER to review this and assess the prudency and efficiency of this pass through cost to consumers given the details are confidential. The use of the ACIL Allen forecast seems to have been a placeholder eg it does not include the network costs AGN will incur, awaiting more SA specific price data. AGN has provided confidential information on the cost to supply in SA over 2026-31. While the actual cost will be a true-up, we

[28] For example see the discussion in the Draft Decision for AusNet Services at pp 16ff https://www.aer.gov.au/documents/aer-attachment-3-operating-expenditure-draft-decision-ausnet-services-distribution-determination-2026-31-september-2025
[29] See pp 195-6 https://www.aer.gov.au/documents/asd-ausnet-edpr-revised-proposal-2026-31-december-2025 and the HoustonKemp report https://www.aer.gov.au/documents/supporting-documents-opex
[30] See p. 4 https://www.aemc.gov.au/sites/default/files/2025-11/19._aer_grc0085_cp_submission.pdf

support AGN's position that the price used must be reasonable in the circumstances and based on a prudent and efficient forecast.

5. Capital expenditure

Our focus here is on the IT transition plan, renewable gas readiness capex and cyber security.

<u>AER Draft Decision</u>

The AER concluded that AGN's proposal did not meet the capex criteria and substituted an alternative forecast of $428m, or 15% below AGN's proposed $503m. This compares with forecast 2021-26 capex of $568.3m in the Final Proposal. The reduction in proposed capex was driven by the completion of the mains replacement program offset by increases in ICT and meter replacement.

On the Better Resets Handbook expectations, AGN met the expectation on genuine consumer engagement and partially met the other expectations on top down testing of the total capex forecast at the category level, evidence of prudent and efficient decision making and evidence of alignment with asset and risk management standards.

The AER accepted the $155m new connections capex as a placeholder awaiting the AEMC's final decision on the costs of new connections. The main reductions were in ICT with concern about the prudency and efficiency of:

- the proposed ICT transition project ($57.8m) as AGN takes over functions previously undertaken under contract by APA – the same concerns as with the associated proposed opex step change of $19.1m,
- moving to SP-3 cyber security profile in the absence of a legislative requirement ($1.5m), and
- proposed meter replacement ($38.4m).

As was the case with opex, in some cases eg ICT projects, the AER indicated that their view might change with additional information and a zero allowance was a place holder awaiting that information.

<u>What AGN is proposing in the RFP</u>

Capital expenditure summary $m (2025/2026)

2021 – 2026			2026 – 2031				
			FP		RFP		
	AER allowance	Actual / Forecast	Proposal	AER DD	Proposal	%chg. vs FP	% chg. vs DD
Gross	$640.4	$594.7	$503.0	$428.0 (-15%)	$446.7m		
Customer contribution	-$0.6	-$26.3	-	-	-$109.5m	-	-
Net	$639.8m	$568.4m	$503.0m	$428.0m	$337.2m	-33%	-21%

The major change from the FP is the removal of a substantial part of new connections capex following the AER's final decision to charge new residential and small business consumers the full costs of their connection. Currently these costs are recovered from all customers. This resulted in a reduction of $109.5m in capex. The reduction is less than the original $155m proposed for new connection because:

- The demand for new residential connections is expected to fall given full cost recovery:

	Residential	Commercial	Total
Gross new connections	30,551	781	31,322
Less impact of connections charge	-6,684	0	-6,684
Revised gross connections	23,866	781	24,647
Disconnections	33,812	812	34,624
Net connections	-9,945	-31	-9,976

- Cost recovery will not start until 1 October 2026.

AGN has provided further information to support the prudency and efficiency on its proposed expenditure on the IT transition project (based on an extensive tender process), cyber security and meter replacement.

<u>Panel comments on the Revised Final Plan</u>

We focus on the IT transition plan, renewable gas readiness and cyber security.

IT Transition

In our submission on the FP we noted the many examples of overspend on IT projects across many networks. Given this and the large uplift compared to the current period, we recommended that the AER closely review AGN's implementation plan. AGN's cost estimate for their preferred 'lift, shift and merge' option had a 25% general contingency risk allowance which added $15.3m. In the DD the AER said[31]:

> "As a general principle we only accept risk allowances in limited circumstances that are specific to a particular project or program. For example, risks that relate to a realistic latent condition with the site(s), or specific risks that are reasonably likely to arise that are beyond the control of the Networks Service Provider. In such cases we review the nature of each type of risk as well as the basis of the calculation of the estimated risk cost(s)...We require further project-specific analysis from AGN to support its risk allowance assessment in its revised proposal."

Since the DD, AGN have consulted with the SARG on their approach to reducing the cost – both base and risk allowance. AGN have now started the project in the current period with a recent tender process reducing the risk allowance to 10-15% ($11.8m) depending on the cost component. The table summarises the changes.

$2025/26m	FP	RFP		
	All in 2026-31	In 2021-26	In 2026-31	Total
Cost before contingency	$45.3m	24.6m	$32.3m	56.8m
Contingency	$15.3m (25% contingency assumption)	2.3m	$9.5?m (granular and bottom up contingency estimate)	11.8m
Total cost	$60.6m	$26.9m	$41.7m	$68.6m

[31] See p. 16 https://www.aer.gov.au/documents/aer-draft-decision-agn-sa-access-arrangement-2026-31-attachment-2-capital-expenditure-november-2025

AGN details its risk analysis and methodology for arriving at the revised level of risk allowance. It presents the case that IT projects are inherently risky as the justification for a high risk allowance. Academic research is presented to justify the case that IT projects have greater risk that other projects in 23 project categories. Four reasons are posited - immaturity (it is a new field vs say building a road), intangibility (intangibility of software also means that there are no physically tangible milestones against which to measure progress as there are for a physical product), goal ambiguity (absence of clear goals leads to requirements volatility and scope creep, and thus higher cost risk) and stakeholder resistance (trying to design a system that keeps everyone across an organisation happy). Not all IT projects go over budget, but when they do, they go massively over budget.

We agree it is a complex area. Our first comment is to commend AGN for the transparency it has provided around how it arrived at its risk contingency amounts. Our main comment is the apparent assumption that even if it is a complex area (thought this particular project seems to be a lot less complex than a greenfield project), it assumes that:

- management oversight of the project development process has correctly identified risks and their scope when they should have, and
- consumers are best placed to pay for a risk not identified when they have no way of mitigating

For example, AGN point to how project scope elaboration has identified the number of applications to be transitioned increasing from 51 to 83 that materially impacted on scope and duration and presumably cost[32]. We have no idea whether this change of scope should have been identified earlier or that it reasonably could not have been at least anticipated (change in scope is a common event in our experience with network ICT projects) given AGN did not have the access to the APA systems it has subsequently obtained.

Even if AGN's proposed budget including the revised risk allowances is approved, AGN can still choose to exceed that amount if new risks arise with its willingness only limited by their view of a CESS risk. One option for AGN is to commit to meeting all costs above the approved budget. This is effectively what Energy Queensland did for the large cost overrun in their DEBBS ICT transformation project[33].

In summary, we continue to recommend that the AER to closely examine the proposal for prudency and efficiency.

Renewable gas readiness

We, along with other consumer advocate submissions, did not support this expenditure for the same reason we did not support the renewable gas certificate scheme – consumers should not have to pay for AGN costs of transitioning to renewable gas unless it is strongly supported through informed consumer engagement.

The DD described the expenditure as[34]:

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[32] See p. 25 Attachment 9.14 https://www.aer.gov.au/documents/agn-sa-attachment-914-response-draft-decision-it-transition-january-2026
[33] See the discussion on pp 34-5 https://www.aer.gov.au/documents/ergon-2025-30-regulatory-proposal-january-2024-0
[34] See pp. 10-11 https://www.aer.gov.au/documents/aer-draft-decision-agn-sa-access-arrangement-2026-31-attachment-2-capital-expenditure-november-2025

> "… largely readiness investments such as weld procedure and hardness testing, incompatible parts replacement and pipeline repair equipment.

After acknowledging the submissions opposing the expenditure, the AER concluded:

> "…given AGN's existing blended renewable gas program our draft decision is to accept this modest expenditure for renewable readiness."

Yet when the AER was discussing the renewable gas certificate step change it noted[35]:

> "We agree with stakeholders' concerns regarding the potential shift of risk and cost of the HypAdelaide project to network users. We note the HypAdelaide project is being progressed by AGN outside the regulatory framework. Forecast network expenditure requires justification as to how the benefits outweigh the costs to network users arising from the expenditure. In this regard, AGN has not specified the type of benefits arising to network users from this expenditure, including through either supporting qualitative or quantitative analysis."

AGN has confirmed that the expenditure relates to preparation for future hydrogen blending that may occur post 2031. This includes weld procedure and hardness testing, incompatible parts replacement and pipeline repair equipment. It does not include expenditure to enable the distribution of current hydrogen blending. In its discussion of AD AGN sees this expenditure as creating real options for a renewable gas future that may or may not eventuate[36].

Given our view that it is very unlikely that there will be economic hydrogen available for blending from 2031, we continue to not support this capex. It has not been consulted on through consumer engagement. These costs should ideally, be paid by AGN or at least considered as speculative capital under rule 84. If AGN are so confident about the future of renewable gas then they should have no concerns about whether this capex would be brought into the RAB in the future.

Cyber security

AGN submits that the AER has misunderstood its proposal. AGN is not proposing to go to SP-3, but to maintain SP-1. Given the standard is constantly maturing, the requirements to maintain a particular SP level increase over time. Being up to date on SP-1 provides the required platform to efficiently move to SP-2 which AGN expects to become an obligation some time over the next five years. We support AGN's approach to cyber security.

The problem for networks now is that there is no legislative requirement to achieve a particular SP level. The AER seems to make a network by network decision on what it thinks is required eg it has allowed Transgrid to go to SP-3 in the current period[37]. For Ausgrid the AER did not see a

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[35] See p. 20 https://www.aer.gov.au/documents/aer-draft-decision-agn-sa-access-arrangement-2026-31-attachment-3-operating-expenditure-november-2025
[36] See p. 8 https://www.aer.gov.au/documents/agn-sa-attachment-65-response-draft-decision-depreciation-january-2026
[37] See p. 22 https://www.aer.gov.au/documents/aer-transgrid-2023-28-draft-decision-attachment-6-operating-expenditure-september-2022

regulatory obligation to go to SP-3 but accepted Ausgrid expenditure proposal to go to a level between SP-2 and SP-3[38]. The AER's view in Ausgrid's case was[39]:

> "...that in the absence of compliance of a regulatory obligation, an assessment of the economic case for the cyber security proposal is required."

It is frustrating to consumers who are very concerned about cyber risks that there is no mandated SP level for electricity and gas networks. This would make everyone's task a lot easier - no consumer engagement required with the AER assessing the prudency and efficiency of the proposed expenditure to get to the mandated SP level. AGN has advised that it may be mandated to achieve SP-2 in 2028. If so then it is important they have a strong SP-1 base to then assess any pass through costs of going to SP-2. We note the current rule change before the AEMC to incorporate AEMO's cyber security role into the gas rules may lead to more formal obligations on gas networks[40].

6. Demand

<u>AER Draft Decision</u>

The AER did not accept the AGN demand forecast but used it as a placeholder until an updated forecast is prepared following the AEMC's decision to allow full cost recovery for new connections. The AER's consultant, Frontier Economics, made a number of comments on the forecasting methodology used by AGN's consultant, Core Energy.

<u>What AGN is proposing in the Revised Final Plan</u>

Total forecast consumption is higher than in the FP – 8.6% for residential and 3.4% for commercial (both due to higher average consumption per connection) and 0.3% for industrial (due to stronger growth for some large customers). It has accepted all of the DD conclusions on both customer numbers and consumption per customer. Revised forecasts are presented and AGN considers that it has addressed the methodological issues.

<u>Panel comments on the Revised Final Plan</u>

While we profess no particular expertise in demand forecasting leaving it to the experts, in our submission on the FP we highlighted the uncertainty facing any demand forecast in the current economic and energy policy environment. Historical trends are no longer of much use in forecasting with AEMO GSOO 2025 forecasts[41] using three ISP scenarios on the impact of electrification of households and businesses and forecast expanded gas fired generation on gas average and peak demand.

This means there is a potential for a material variance between forecast and actual demand which has important implications for risk allocation between the network and its customers and the tariff pathway. This has led to the hybrid approach to the form of revenue control.

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[38] See pp 13-17 https://www.aer.gov.au/documents/aer-final-decision-attachment-5-capital-expenditure-ausgrid-2024-29-distribution-revenue-proposal-april-2024-0

[39] Ibid p. 15

[40] https://www.aemc.gov.au/rule-changes/gas-cyber-security-roles-and-responsibilities-aemo

[41] https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2025/2025-gas-statement-of-opportunities.pdf?rev=209c6536e82a4be9aec35360d93f272b&sc_lang=en

We find it difficult to understand why direct or cross-price elasticity of gas seems to have no impact on forecast demand and hence are excluded from the normalisation process. We leave the AER to decide if the demand forecasts meet the rules requirements.

Given the level of uncertainty around demand forecasts we hope that the current AEMC review of the gas regulation framework examines options to reduce the level uncertainty and impact on consumer bills.

7. Revenue and Prices

Our focus here is on tariff structure for all customers, but particularly for commercial tariffs, as well as service abolishment charges.

<u>AER Draft Decision</u>

Tariff structures – residential and small business

From the start of this reset process the AER has made clear its desire to see a flattened tariff structure to support the emissions objective in the NGO. In its final decision in November 2024 on AGN's Reference Service Proposal it said[42]:

> "By developing tariff structure reform options in collaboration with stakeholders, we consider AGN SA can better reflect the emissions reduction aspect of the updated NGO. In developing its potential tariff structure reform(s), AGN SA should consider the pace of change, bill impacts on high consumption customers and the need for adequate transition periods." (p.2)
>
> "Declining block tariffs do not align with the NGO which now includes an emissions reduction element. In developing its potential implementation pathway(s), AGN SA should consider the pace of change, bill impacts on high consumption customers and the need for adequate transition periods." (p.16)

In the DD the AER rejected AGN's declining block tariffs (which were slightly flatter than currently applying) because there was only 'modest flattening' saying it encouraged consumption which is in conflict with the emissions reduction aspect of the NGO[43]:

> "Under the declining block structures 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, two 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."

The AER 'requires' AGN to:

- Flatten its volume (small – residential and commercial) customer tariffs further in its revised proposal, by retaining a fixed charge (which is used to recover large sunk, fixed costs) and a block 1 but amending subsequent blocks to a single flattened block 2

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[42] https://www.aer.gov.au/documents/agn-sa-2026-31-access-arrangement-reference-service-proposal-final-decision

[43] See p. 11 https://www.aer.gov.au/documents/aer-draft-decision-agn-sa-access-arrangement-2026-31-attachment-5-reference-services-tariffs-and-non-tariff-components-november-2025

- For its demand (large - industrial) customer tariffs, required AGN to[44]:

> “...consider in its revised proposal similarly (i.e. to the volume (small) customers) flattened block tariff structures for the 2026-31 period. To the extent that AGN modelling indicates customers would benefit from time to transition, it should lay out a clear plan to transition to flatter demand tariffs.”

The detailed bill impact modelling of the alternative revised block structures[45]:

> “...should cover at least disaggregation into differing consumption levels and identify the number of customers at each consumption level.”

The AER was open to having a transition plan for flatter tariffs over the 5 year period.

Service abolishment pricing

The AER had previously approved the addition of an abolishment service as an ancillary reference service. While the AEMC’s Draft Determination supporting full cost abolishment fees was published in October[46], it is proposing a phased introduction from 2027 with distributors obligations commencing at the start of their subsequent AA period. This means that were the final determination follow the draft, it would not apply to AGN until 2031-36. This has led to the AER proposing a two part pricing for the same service in 2026-31:

(i) $257 where the customer is permanently disconnecting to electrify
(ii) $1,000 (AGN proposed $1,250, but the AER’s benchmarking against other networks concluded $1,000 was more reasonable) to be paid by a customer planning knock downs and rebuilds and renovations ie sites that do not have the option of a temporary disconnection service

The AER sees high abolishment tariffs appearing as exit fees to customers, which will inhibit the achievement of jurisdictional emissions reduction targets. Socialising part of the small customer connection abolishment costs would remove the financial barrier to abolishments being undertaken in circumstances where other jurisdictions have deemed abolishments appropriate due to safety considerations. Socialising costs is a placeholder as the most pragmatic way forward when there is no alternative approach to managing the safety issues linked to disincentivising customers from requesting the abolishment service.

The AER did not receive any advice from the SA OTR on the partially socialised abolishment tariff and safety implications and indicated that its view may change with that advice.

This two part tariff approach is consistent with the AER’s decision for Jemena NSW for 2025-30. The AER’s logic is that it would reduce the level of cross-subsidisation not just with the abolishment but then any reconnection would require the new customer to pay a full cost connection fee. This would manage the ‘moral hazard’ (where one party takes on more risk because another party bears the cost of that risk) for customers will not be incentivised to claim they will not re-connect.

[44] Op cit p.12
[45] ibid
[46] https://www.aemc.gov.au/news-centre/media-releases/aemc-proposes-new-rules-manage-customers-leaving-gas-and-protect-consumer-interests

What AGN is proposing in the Revised Final Plan

AGN has undertaken the analysis and engagement requested by the AER in the DD. AGN maintains its view that a 'flat tariff' structure is an inefficient pricing structure for distribution services with large fixed-asset costs.

Tariff structures – residential and small business, commercial

The DD only proposed the flatter tariff structure. Actual tariffs were up to AGN to propose showing the required modelling on the specific tariffs.

	RESI	Commercial	Industrial
Approx customer numbers	478,000	11,500	110
Annual demand (PJ)	6.3	3.2??	9.8
No of blocks			
Current	3	4	
AER DD	2	2	Consider change
AGN RFP	2	3	No change

As we discussed above, consumer engagement subsequent to the DD showed overall support for a gradual transition to flatter tariffs as being the fairest approach.

AGN has adopted the AER's recommended two block structure for residential customers with prices set so that there is a cap of a 16% increase. The bill impact analysis solely measures the impact of change in tariff structure, not other revenue related proposals and assuming the retailer passes though the tariff (which, based on current experience is unlikely to be the case). Depending on an individual customer's consumption pattern and assuming the retailer passes through the tariff, this two block structure is expected to result in around only 30% of customers having a bill increase.

AGN decided against moving to the two block structure for commercial customers, instead moving from the current four blocks to three blocks. This is because moving to a two block structure would have meant significant bill reductions for some higher consumption customers – what the AER is saying it does not want.

Tariff structures – industrial customers

AGN did 'consider' flattening of tariffs for larger industrial customers but rejected the move. Tariffs for these customers are capacity based depending on MDQ, not consumption based, and vary by location (seven regional categories) reflecting the cost of supply. This means that tariffs are already relatively flat and further flattening to a two block model would simply redistribute costs among the small customer base with a small number of customers bearing significantly higher costs and a large proportion have relatively small reductions.

AGN provides modelling of the Adelaide Northern and Adelaide Central regions to support this conclusion. There is a risk that the large cost increases will lead to closure of manufacturing sites with the product having to be produced at another site. In this case emission reduction may be achieved by demand destruction at a particular site but production may simply move to another location without any emission reduction.

AGN argues that changing network tariffs is a very inefficient approach to emission reduction when other polices like the Safeguard Mechanism are much more efficient.

Service abolishment pricing

AGN's proposal in the FP was a single charge of $257 for a customer initiated abolishment based on 20% of the cost reflective estimate of $1,250, noting that this may change depending on the outcome of the AEMC's decision on the JEC rule change for full cost abolishment pricing. In the RFP, AGN is proposing non-discriminatory full cost recovery of $1,250 for all disconnections:

- While the AEMC draft determination proposes adoption from 2027, the current rules allow full cost abolishment
- Given the AEMC final determination is due in February there is time to incorporate it into the AGN final decision in April/May
- There is no administrative impediment to a quick introduction - AGN is introducing the Victorian up front connection cost from 1 October 2026
- There is no difference in this cost between the cost for a permanent disconnection or for a rebuild so a differential cost is discriminatory pricing
- Attachment 8.6 provides a cost build-up to justify the $1,250 charge
- The two part tariff will be impossible for AGN to enforce – consumers will quickly realise the lower cost option and advice their retailer it is a permanent disconnection; the contractor AGN employs to do the work will not care about the reason given by the customer to the retailer
- The AEMC draft determination did not appear to be concerned about the moral hazard problem the AER raises; it also highlighted the inefficiency and inequity of a partial cost recovery approach the AER is now proposing; indeed the AER in its submission on the rule change noted how unfair and inequitable is a partial cost recovery approach[47]
- There are benefits in applying the rule in 2026-31 rather than waiting until 2031-36 eg the AER is introducing a lot of uncertainty in customers minds with the constantly changing rules which adds to compliance costs consumer have to bear – the AEMC's draft determination commented on the importance of clear consistent rules across the NEM
- The SA OTR has not supported the AER approach and that the AER's concern about the safety implications of full cost recovery (customers will undertake unsafe disconnection to avoid the full cost) is not supported – it is a human behavioural issue, not a safety issue; the SA OTR has advised AGN that the outcome of the AEMC rule change should 'solve the issue'; this is not an issue that justifies a 5 year delay.

<u>Panel comments on the Revised Final Plan</u>

Tariff structures

Our previous submissions on tariffs have highlighted the difficulty of ensuring those participating in tariff structure engagement (residential and small business customers) had sufficient understanding of a very complex topic. This included the broader issues on tariff reform and the revised NGO as well as how tariff structure changes might affect their particular bill.

Our previous submissions also highlighted how flattening of tariffs will create winners and losers. Falling consumption means there will be heavier reliance of fixed rather than volumetric charges. But that has distributional implications for high gas users across each customer class

[47] See p. 4 https://www.aemc.gov.au/sites/default/files/2025-11/19._aer_grc0085_cp_submission.pdf

who are less able to electrify either because of they are renters, the high cost of conversion where conversion is technically possible or where a technical constraint in a manufacturing process means they cannot electrify.

However, this does not seem to be a consideration of the AER. The AER's focus seems to be that declining block tariffs lead to higher consumption and hence higher emissions. So the obvious way to decrease consumption was to increase the marginal cost/MJ. However:

- Flatter tariffs produce winners and losers – some customer bills will decrease which suggests that their consumption and emissions might increase (which is why AGN did not go for a two block structure for commercial customers); some customer bills will increase including larger households who cannot afford electrification but their emissions and consumption may not decrease because they have no alternative option
- The AER provides no detailed modelling to support its assumption that flatter tariffs will efficiently decrease consumption, repeating its advice from November 2024 in the DD[48]:

> "The AER's November 2024 decision on AGN's reference service proposal encouraged AGN to 'flatten' its declining block tariff structures to better contribute to the emissions reduction element of the NGO.

Back in its original reference service proposal in July 2024, AGN provided modelling of a fully flat tariff structure that found the value of any benefit (using an $88/tonne carbon price) from the 2% reduction in demand and assuming the increase network tariffs are fully passed through by the retailer, are negligible – on average 0.02-0.04% of the annual bill[49]. We understand that the AER has not engaged with AGN on this analysis, simply repeating their principal of declining block tariffs being inconsistent with the NGO.

We support AGN's approach to not modify the Tariff D structure. Simply reallocated costs among a small number of customers with a small proportion of big losers and a large proportion of small winners will only achieve emissions reduction through demand destruction from users who cannot electrify for technical or economic reasons.

We conclude that AGN has done all that the AER asked it to do in the DD on tariffs. AGN has developed its tariff structure reforms in collaboration with stakeholders looking at different flattening options, bill impact on high consumption customers and the need for adequate transition period. In the December 2025 Phase 4 engagement session, participants were aware of the AER's position that flatter tariffs would result in increased prices and reduced emissions to meet the NGO' with this in the background reading[50]:

> "The AER has asked us to consider a different approach with flatter tariffs, in other words, charging more of the same price for all gas used, rather than offering cheaper rates at higher usage levels. The aim is to ensure prices don't encourage increased gas consumption and to help support emissions reduction."

[48] See p. 5 https://www.aer.gov.au/documents/aer-draft-decision-agn-sa-access-arrangement-2026-31-attachment-5-reference-services-tariffs-and-non-tariff-components-november-2025
[49] See p. 32 https://www.aer.gov.au/documents/agn-sa-2026-31-reference-service-proposal-1-july-2024
[50] See p. 14 https://www.aer.gov.au/documents/agn-sa-attachment-56-response-draft-decision-background-information-customer-reading-pack-january-2026

AGN came to a conclusion that is reflected in the RFP, not what the AER seemed to, a priori, expect. The primary concern of participants in the engagement was affordability and fairness in tariff design.

The recent Productivity Commission Report[51] on options to reduce carbon emissions noted that climate policies can vary enormously in cost effectiveness and it is critical that these policies are cost effective. Gas consumers need to be convinced that the AER's tariff approach is a prudent and efficient way of doing that. We look forward to the AER providing that evidence eg through a marginal cost of abatement curve, in their Final Decision.

Service abolishment pricing

In seeking support for its position, the AER says:

> "The SARG has supported the addition of the abolishment service and continuation of the existing policy of *fully socialising* abolishment charges, recognising that there are safety and equity concerns about how this might be implemented."

Our submission on the Draft Plan we argued that AGN should maintain its current a no-charge abolishment policy in 2026-31 unless and until there is clear evidence that costs are material, unavoidable and justified through a robust public process. Our comments in our FP submission did not expressly support fully socialising, focusing on the potential impact of the JEC rule change and noting that the JEC proposal received overwhelming support from the nearly 30 stakeholder submissions to the AEMC.

The AEMC's draft determination to support full cost recovery changes the policy context. Based on detailed discussions with AGN as it prepared its RFP, we believe:

- the two part discriminatory charge proposed by the AER is administratively very complex and may lead to a significant increase in costs were AGN seeking to ensure customers are not misleading their retailer about the reason for their abolishment; a discriminatory tariff designed to address a moral hazard simply may generate its own moral hazard as customers seek to avoid the $1,000 cost when they are renovating or rebuilding, and
- delaying implementation of the rule change to the next period just to introduce such a full cost recovery tariff from 2031 is not in long term interests of all consumers. They would have three different abolishment charges in 7 years - $85 in 2025-6, $250/$1,000 for 2026-31 and $1,000 from 2031 – very confusing.

We agree with AGN's position that all customers should be charged the full prudent and efficient cost of the abolishment service. The AER's role is to assess that cost and it has proposed $1,000 though the cost build up now provided by AGN might change their view.

The table summarises the different cases for an abolishment charge. It is unclear what the AER wants the fee to be for a customer who is renovating/rebuilding with an all- electric building - $250 or $1,000?

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[51] https://www.pc.gov.au/inquiries-and-research/net-zero/report/

	No renovation/rebuild	Renovation/rebuild
Permanent disconnection to the property for fully electrified future	$250	$1,000?
Temporary disconnection with a view to reconnection	-	$1,000

If it is $1,000 then there is a strong incentive for a customer in that category to simply say to their retailer (who passes on the information to AGN) they want a permanent disconnection and provide no or misleading information on renovation/rebuild. For AGN to assess whether that customer is renovating or rebuilding (and hence need to pay $1,000) would require a high administrative cost to check individual abolishments which AGN has said they are not prepared to do. The AGN contractor coming to the site to disconnect is not going to check whether the property owner has followed the rules.

If seems that in seeking to remove a moral hazard the AER's approach may create a new one at the same time as adding complexity and cost.

13 February 2026