Attachment 8.5

Response to Draft Decision on Operating Expenditure

Revised Final Plan 2026/27 – 2030/31

January 2026

PUBLIC

Australian Gas Networks

1 Response to Draft Decision on Operating Expenditure

The operating expenditure (opex) we incur supports the safe, efficient and reliable delivery of gas to homes and businesses every day. It ensures we can meet the service expectations of our customers and the day-to-day needs of our workforce.

1.1 Overview

This attachment sets out our response to the AER's Draft Decision on operating expenditure (opex) for the AGN SA network over the next (2026/37 to 2030/31) Access Arrangement (AA) period.

The Revised Final Plan forecast opex for the next AA period is $434.0 million[1], which is $37.8 million (or 10%) higher than the forecast opex in the AER's Draft Decision but $30.1 million (or 7%) lower than our original Final Plan submitted in July 2025. Changes relative to our original Final Plan submitted in July 2025 are:

- Application of the actual operating expenditure incurred in 2024/25 as the base year and updated inflation estimates (+$4.6 million on our Final Plan forecast);
- Minor revision to the forecast for the capex to opex step change as agreed by the AER, for alignment with the capex forecasts (+$0.5 million);
- Removal of the renewable gas certificate purchase scheme as an opex step change from 2028/29 due to a change in anticipated timing concerning implementation of the Hydrogen Park (HyP Adelaide) project (-$26.0 million);
- Revised forecast for the non-recurrent IT costs (as a temporary opex step change) associated with the transition of IT systems to our environment, one which will yield ongoing opex savings for customers (+$0.5 million);
- Updated unaccounted for gas (UAFG) forecast (-$8.2 million) to reflect the adjusted volume forecast by the AER and our revised price forecast based on further commercial (confidential) information we have received about price for the South Australian network;
- Revised debt raising costs (+$0.4 million) based on application of the AER's latest accepted benchmark (as a proportion of the debt allowance); and
- Updated labour escalation forecasts consistent with the AER's Draft Decision and updated net output growth forecasts to reflect the impact of the new connections charge and a higher number of forecast disconnections, offset by the assumption for zero productivity growth (-$1.9 million).

Compared with the AER's Draft Decision we have also reinstated the same forecasts for opex step changes relating to cybersecurity step change ($1.2 million) and the abolishments of redundant sites on safety grounds ($4.6 million) as we proposed in our Final Plan.

Table 1.1 below summarizes our revised opex forecast compared to our Final Plan and the AER's Draft Decision, including the key drivers for change.

[1] This excludes the forecast of the Ancillary Reference Services over the next AA period.

Table 1.1: Summary of revised opex forecast ($million, June 2026)

	Final Plan	AER Draft Decision	Revised Final Plan	Drivers for change
Opex Base Year (post increment and other adjustments)	338.7	336.0	343.3	✓ We have updated base year opex for 2024/25 actuals, consistent with the RIN. ✓ We have also applied updated forecast inflation (to December 2027) in the opex model from the RBA's November 2025 statement on monetary policy.
Trend factor: Labour cost escalation Net output growth	5.9	4.0	4.0	✓ We have updated the trend factor applied to base year costs to reflect the AER's Draft Decision to apply an average of the forecast average annual Wages Price Index (WPI) growth by BIS Oxford Economics and its own consultant, and different weightings for labour and non labour cost escalation components. ✓ We have also adjusted the output growth factor to be negative due to revised connection forecasts, consistent with reduced demand forecasts. We have set the proposed productivity adjustment to be zero, in response to the negative net output growth forecast since with a contracting network, no economies of scale can be achieved.
Change in capitalization of overheads - step change	32.1	32.1	32.5	✓ We have maintained our Final Plan position, which has been endorsed by the AER in its Draft Decision to reclassify a portion of overheads more akin to opex, but we have updated the amount to align with our capex forecasts (as the AER also identified was necessary).
Renewable gas certificate purchase scheme - step change	26.0	Nil	Nil	✓ As advised to the AER ahead of its Draft Decision, we removed the proposed step change based on timing of the HyP Adelaide project. Commissioning of the project and implementation of the scheme will likely occur at the end of the AA period or potentially early the following period. Given the revised timing we consider it more appropriate to consider any step change as part of the subsequent 2031/32 to 2035/36 AA period, noting the project is consistent with our Net Zero ambition and the SA Government remains supportive.
IT transition – non-recurrent step change	18.6	Nil	19.1	✓ We have adjusted the proposed step change amount in line with actual expenditure requirements and a review of labour cost assumptions and have provided further evidence to show the justification for the IT transition expenditure for AGN SA.
IT applications enhancements and upgrades step change	4.1	4.1	4.1	✓ We have not amended this step change which has been accepted as prudent and efficient by the AER in its Draft Decision.
Cybersecurity step change	1.2	Nil	1.2	✓ In response to the AER's Draft Decision, which endorsed the need for the uplift to the cyber security program but did not allow the expenditure on the basis that it should be covered by the opex

	Final Plan	AER Draft Decision	Revised Final Plan		Drivers for change
					'trend factor', we present a number of reasons why the trend factor is not a reasonable option, and submit that other savings and efficiencies are already being factored into the opex forecast.
Redundant site abolishments step change	4.6	Nil	4.6	✓	In response to the AER's Draft Decision that we did not establish a sufficient safety case to warrant the proposed abolishments, we have provided more information about the incident risk associated with leaving pipelines at these redundant sites and the need to permanently remove them, as supported by the Office of Technical Regulator (OTR).
Category specific forecast - UAFG	27.9	14.6	19.7	✓	We accept the AER's Draft Decision for forecast UAFG volumes based on the average of the last three years, including one year of unsettled data to 2023/24 (rather than all settled data to 2022/23 as we proposed). However, we have proposed a new price for UAFG based on new commercial information specific to the SA distribution network and do not accept the AER's use of the wholesale gas price from the GSOO as an appropriate price forecast for UAFG.
Debt raising cost	5.1	5.5	5.5	✓	We accept the AER's application of its latest benchmark for debt raising costs (8.65 basis points as a share of the debt allowance).
Total opex	**464.1**	**396.2**	**434.0**		

1.2 Stakeholder and customer feedback

In preparing the Revised Final Plan we have continued to engage with stakeholders, including our South Australian Reference Group (SARG) and other stakeholders. We provided information about the removal of the proposed renewable gas certificate purchase scheme with members of our SARG (29 October 2025), ahead of the AER's Draft Decision and we held a SARG meeting on 11 December 2025 following the Draft Decision where we shared our proposed responses to the expenditure decisions. We have also responded to feedback through submissions to the AER on our Final Plan.

A summary of the feedback provided on our opex, following the submission of our Final Plan, is provided in Table 1.2 below.

Table 1.2: Summary of customer and stakeholder feedback

Customer and Stakeholder Feedback	Our Response
On our proposed base year opex and trend escalation: • The SARG review Panel noted that because AGN has followed the AER base, trend, step methodology, much of the forecast opex is not subject to consumer comment.[2]	We have updated our base year to reflect actual 2024/25 opex as reported in our recent RIN submission. On the trend, we have updated our customer number forecasts to align with our revised demand forecasts.

[2] SARG Panel submission, p. 25.

<table>
<tr><th>Customer and Stakeholder Feedback</th><th>Our Response</th></tr>
<tr><td>The SARG Review Panel welcomed AGN absorbing an increase in insurance premium costs (+$0.3m) as part of base year opex.[3]
CCP33 questioned AGN's assumptions behind the trend if increases in customer numbers do not materialize and network expansion is curtailed, and therefore whether the forecast trend is reasonable given the uncertain future of gas. It considered that it was a matter for the AER to consider in its assessment.[4]</td><td></td></tr>
<tr><td>On the proposed step change for the purchase of renewable gas certificates for the proposed HyP Adelaide project:
SARG indicated that it does not support consumers paying for HyP Adelaide costs unless strongly supported through informed customer engagement.[5]
CCP33 agreed that there is no certainty around the large-scale economic viability of hydrogen gas and did not support customers paying for the certificates.[6]</td><td>The timing of delivery of the HyP Adelaide project is now likely to be later than anticipated in the Final Plan. For this reason, we have removed this opex step change for the purchase of renewable gas certificates as part of a jurisdictional scheme from our opex proposal.</td></tr>
<tr><td>On the continuation of the Priority Services Program:
The CCP noted AGN had ongoing customer and SARG support for its Priority Services Program introduced in the current regulatory period and covered its base year opex and commended AGN for its work to support customers experiencing hardship.[7]</td><td>We are continuing to propose the Priority Services Program, which forms part of our base year opex and our Final Plan indicated various program enhancement and reach initiatives.[8]</td></tr>
<tr><td>On the proposed change to capitalization of certain overheads:
The SARG review Panel considered it a matter for the AER.[9]
CCP33 indicated that AGN's reasoning for this proposed change was unclear and that more engagement could occur.[10]</td><td>We have explained the need for the change with expenditure more akin to opex.[11] We engaged on this proposal at draft and final plan stages with limited other feedback received and as noted by the AER, the approach is a reasonable reallocation of expenditure that it approved in the Victorian distribution network AAs for 2023-2028. The AER</td></tr>
</table>

[3] SARG Panel submission, p. 6.
[4] CCP33 Submission, p. 34.
[5] SARG Review Panel, Submission on AGN(SA) 2026-31 Access Arrangement Proposal - August 2025 (SARG Panel submission), p 26.
[6] CCP33 - Advice to AER - Submission on AGN(SA) 2026-31 Access Arrangement Proposal - August 2025 (CCP33 Submission), p. 33.
[7] CCP33 Submission, p. 32.
[8] AGN Final Plan, p. 83.
[9] SARG Panel submission, p 25.
[10] CCP33 Submission, p. 32.
[11] AGN Final Plan, pp. 86-87.

Customer and Stakeholder Feedback	Our Response
	has approved the proposed step change for AGN SA in the Draft Decision.[12]
On our ICT and cybersecurity step changes: • CCP33 accepts the need to continue to invest in ICT and cyber security, but AGN needs to explain the customer benefits.[13]	The AER accepted the proposed step change for IT application upgrades and enhancements as prudent and efficient, consistent with its position on the similar proposed capex for IT. It also accepted the need for the proposed cybersecurity uplift but decided it should be covered by the opex trend factor (or base year) rather than as an opex step change. We submit that this approach risks under-resourcing critical cybersecurity needs. For the IT Transition, we have provided additional information about customer benefits by way of annual opex savings being achieved (compared with the previous service delivery approach) by the end of the AA period in section 1.4.3 and Attachment 9.14.
On our UAFG forecasts: • SARG Panel indicated that it would leave it to the AER to review the confidential attachment regarding UAFG Strategy and assess the prudency and efficiency of this pass-through cost to consumers.[14]	We have accepted the AER's Draft Decision on the approach to setting forecast UAFG volumes but have proposed a revised forecast price for UAFG based on recent commercial information about price for the provision of UAFG for the SA network (Confidential Attachment 8.7).

1.3 AER Draft Decision

The AER's total opex forecast of $396.2 million is $67.9 million ($2025/26) or 15% lower than our Final Plan forecast of $464.1 million. The decrease to forecast opex for the next AA period compared to our Final Plan is mainly related to:

- Rejection of the proposed step changes for the jurisdictional scheme to purchase renewable gas certificates ($26.0 million), abolishment of redundant sites on safety grounds ($4.6 million), the ICT transition ($18.6 million), and cybersecurity ($1.2 million).
- Adjusting our UAFG forecast costs (-$13.3 million) to account for:
    - Lower forecast UAFG volumes, and
    - Lower forecast price
- Applying a different trend forecast, mainly for different labour cost escalation forecasts (-$1.9 million);
- Changes to base year forecasts and inflation updates (-$2.7 million).

These reductions were offset by an increase to debt raising costs (+$0.4 million) for application of its latest benchmark rate (calculated as a share of the debt allowance).

[12] AER Draft Decision, Attachment 3, p. 18.
[13] CCP33 Submission, p. 33.
[14] SARG Panel submission, p 26.

We have provided a summary of the AER's Draft Decision in respect of our opex for the next AA period in Table 1.3 below.

Table 1.3: Summary of the AER's Draft Decision on our opex

	AER Draft Decision	AER Comment
Base - base year	Accept	Accepted 2024-25 as the appropriate year from which to forecast opex for the next AA period but adjusted the AGN forecast based on nine months of actuals with updated 2024-25 estimates and inflation.[15]
Trend - Input cost escalation	Modify	Applied input cost escalation (averaging 0.54% from 2026/27 to 2030/31 rather than our forecast of 0.76%) by: • applying lower average annual labour price growth of 0.92% (compared with our forecast of 1.02%) based on an average of forecast annual growth in the wage price index (WPI) for the electricity, gas, water and waste services (utilities) industry from Oxford Economics and forecasts of the same by the AER consultant, Deloitte Access Economics, rather than a weighted average of WPI forecasts by Oxford Economics for the utilities industry and the construction industry in South Australia, as we had proposed in the Final Plan.[16][17] • applying the same forecast non-labour real price growth rate of zero.[18] • applying different benchmark weights to account for the proportion of opex that is labour and non-labour (68% and 32% compared with our forecasts of 71% and 29% respectively).[19]
Trend - Output growth	Accept	Adopted our approach to forecast output growth with a forecast annual growth of 0.32%.[20]
Trend - Productivity factor	Accept	Accepted our proposed annual productivity growth rate of 0.4%.[21]
Step change - Purchase of renewable gas guarantee of origin certificates	Reject	Not satisfied that the proposed step change would represent prudent and efficient expenditure and noted stakeholders' concerns about the risk and cost for network users, and the lack of supporting information on details and timelines.[22]
Step change - Change in capitalization policy regarding treatment of overheads	Accept	Approved proposed expenditure as a reasonable and efficient reallocation from capex to opex, noting the change did not result in an increase to AGN's total expenditure and aligns with the AER's final decision for AGN's (Victoria and Albury) 2023–28 access

[15] AER, Draft Decision, Attachment 3, pp. 10-11.
[16] AER, Opex Model, "Calc | Opex forecast" tab.
[17] AER, Draft Decision, Attachment 3, pp 12-15.
[18] AER, Draft Decision, Attachment 3, p. 13.
[19] AER, Draft Decision, Attachment 3, p. 13.
[20] AER, Draft Decision, Attachment 3, p. 16.
[21] AER, Draft Decision, Attachment 3, pp. 16-17.
[22] AER, Draft Decision, Attachment 3, pp. 19-20.

	AER Draft Decision	AER Comment
		arrangement. The AER also noted that a minor update to the opex forecast was required to amend a minor discrepancy with the capex forecast.[23]
Step change – IT Transition	Reject	Not satisfied that AGN had provided adequate information to demonstrate that the proposed expenditure is for AGN and therefore provided an amount of zero in the Draft Decision. The AER seeks additional information from AGN to address the issues raised in its Draft Decision.
Step change - Application upgrades and Enhancements	Accept	Accepted the proposed IT enhancements and upgrades as prudent and efficient expenditure.
Step change – Cybersecurity	Reject	Accepted that the proposed uplift in cybersecurity reflected prudent investment in AGN's cyber security maturity, including through a risk-based approach, and that AGN should develop capabilities to meet all new regulatory obligations. However, the AER found that the proposed step change risks double counting costs already provided through AGN's base-step-trend forecasting approach because it is relatively small ($1.2 million) and so must be already accounted for.[24]
Step change - Abolishments for safety at redundant sites	Reject	Did not accept the safety case that we put forward for the need for the abolishment of 3,500 redundant sites in the next AA period, where the meter has been removed for at least 24 months. The AER posed questions to AGN to better substantiate the need for the abolishments on safety grounds, including concerning: • the regulatory obligation to abolish, • the risk of incidents without abolishment, • the selection of the sites (and the chosen extent of dormancy of two years), and • the Office of Technical Regulator's (OTR) position on the need for the program.[25]
Category specific forecast - UAFG	Modify	Reduced our UAFG costs to $14.6 million over the next AA period due to the difference in estimating:[26] • The annual average volume of UAFG over the last three years. It considered how UAFG volumes are likely to continue to decrease beyond the 3-year period to 2022-23 based on settled data as we had submitted and so applied the 3-year average to 2023-24 using one year of unsettled data. • The forecast price of UAFG on the basis that the proposed forecast price was based on UAFG for another network outside South Australia. The AER

[23] AER, Draft Decision, Attachment 3, p. 18.
[24] AER, Draft Decision, Attachment 3, pp 23-24.
[25] AER, Draft Decision, Attachment 3, pp 22-23.
[26] AER, Draft Decision, Attachment 6, pp. 37-40.

	AER Draft Decision	AER Comment
		observed that this price was significantly higher than the wholesale gas price projections prepared by ACIL Allen for AEMO's 2025 Gas Statement of Opportunities, and so it instead applied that price as the forecast.[27]
Category specific forecast - Debt raising costs	Modify	Accepted our proposed debt raising costs in principle but applied an updated benchmark assumption (a share of 8.65 basis points of the debt allowance), and for this reason accepted $5.5 million compared with our proposed costs of $5.1 million for the next AA period.[28]

Note: In this 'traffic light' table, green shading represents the AER's acceptance of our Final Plan, orange represents the AER's modification of our Final Plan and red shading represents the AER's rejection of our Final Plan.

1.4 Our Response to the Draft Decision

The Revised Final Plan forecast opex for the next AA period is $434.0 million, which is $30.1 million lower than our Final Plan and $37.8 million higher than the AER's Draft Decision forecast opex on account of:

- Updated base year forecasts for the actual RIN estimates (for 2024/25) and upward revisions to the inflation forecasts (+$7.3 million compared with the AER Draft Decision);
- Resubmission of the opex step changes for capex to opex (with updated costs +$0.5 million), cybersecurity (+$1.2 million), the ICT transition costs (with updated costs +$19.1 million) and abolishments on safety grounds (+$4.6 million) but removal of the step change for renewable gas certificate purchases, consistent with the AER's Draft Decision,[29]
- Updated UAFG price forecasts (+$5.1 million), and
- Updated trend forecasts (incorporating updated labour price escalation, customer number and productivity forecasts) (no net change).

A summary of our response to the AER's Draft's Decision is provided in Table 1.4 below.

Table 1.4: Summary of our response to the AER's Draft Decision on our opex

	AER Draft Decision	Our response	Our Comment
Base year	Accept	Modify	We have accepted the AER's Draft Decision in principle but have updated our base year to reflect actual 2024/25 opex as reported in our recent RIN submission. We have also updated 2025/26 inflation for the RBA's forecast in its November statement of monetary policy (see section 1.4.1).
Trend factor	Modify	Modify	We have accepted the modification to our trend factor by the change in input cost escalation by the AER but have adjusted the output growth

[27] AER, Draft Decision, Attachment 3, pp 25-26.
[28] AER, Draft Decision, Attachment 6, p. 37.
[29] We also accept the AER's Draft Decision on the IT opex step change ($4.1 million).

	AER Draft Decision	Our response	Our Comment
			factor (which is now negative) for updated customer numbers aligned with the revised demand forecasts and zero productivity growth accordingly (see section 1.4.2).
Step - Purchase of renewable gas guarantee of origin certificates	Reject	Accept	Because of a change in anticipated timing of the implementation of the HyP Adelaide project we have withdrawn the expenditure from the opex proposal for the next AA period, pending further progression for the subsequent AA period.
Step - Change in capitalization policy regarding treatment of overheads	Accept	Accept	We accept the AER's Draft Decision and have also made a minor revision to the estimate to align with the capex forecast, as noted by the AER was required.
Step – IT Transition	Reject	Modify	We have provided additional information to demonstrate the prudency and efficiency of the proposed IT transition expenditures, including the non-recurrent operating expenditure step change. See section 1.4.3 and Attachment 9.14 for further discussion on the IT transition, and in particular section 3.3.4 for operating expenditure.
Step – IT application upgrades and enhancements	Accept	Accept	We accept the AER's Draft Decision that the step change reflects prudent and efficient expenditure.
Step - Cybersecurity	Reject	Reject	We provide a number of reasons as to why the trend factor is not sufficient to cover the additional expenditure required for the uplift to cybersecurity, including that we have already factored in other material savings in the overall opex forecast and because output growth is now forecast to be negative such that there is no positive trend allowance for growth (see sections 1.4.2 and 1.4.3).
Step - Abolishments for safety at redundant sites	Reject	Modify	We provide additional information about the safety case for the abolishments to address the AER's questions regarding the step change, including the need for abolishments at the selected sites given how long they have been dormant/redundant, and the risk of adverse incidents occurring. We also demonstrate support from the OTR for these activities in the interests of safety (see section 1.4.3 and Attachment 8.6).
Category specific forecast - UAFG	Modify	Modify	We accept the AER's Draft Decision on the approach to setting forecast UAFG volumes, noting there is a risk that the data for 2023/24 (upon which its three-year average is based) might change before it is settled. We propose a revised price forecast for UAFG compared with the AER's Draft Decision, consistent with new commercial information we have about a likely negotiated price outcome specific to the SA market. The GSOO wholesale gas price forecast as proposed by the AER in its Draft Decision is not an appropriate proxy

	AER Draft Decision	Our response	Our Comment
			because it does not account for commercial objectives by retailers concerning the provision of UAFG for the AGN SA network, nor does it include a retailer's margin (see section 1.4.4 and Confidential Attachment 8.7).
Category specific forecast - Debt raising costs	Modify	Accept	We have accepted the AER's Draft Decision and have not proposed any further changes.

Note: In this 'traffic light' table, green shading represents acceptance, orange represents a modification, and red shading represents rejection.

The following sections outline the reasons for our updated opex forecast in more detail and our response to the AER's Draft Decision on opex in this Revised Final Plan.

1.4.1 Base year

We have updated our base year for actual costs reported in our Annual RIN submission. Our base year opex forecast post adjustments and including inflation for the 18 months to June 2026 is $68.7 million, which is $0.9 million above our forecast base year costs presented in our Final Plan and $1.5 million higher than approved in the AER's Draft Decision. The differences are driven by small revisions to the estimates and updates to inflation forecasts.

Removal of non-recurrent costs and category specific forecasts

Our base year opex is adjusted by $2.0 million for the movement in provisions, debt raising costs and UAFG costs. These estimates have been updated on the AER's Draft Decision for the opex forecast which included $6.8 million for these adjustments, with the difference mainly due to a higher UAFG estimate (by $4.7 million) before final settlement of UAFG data.

1.4.2 Trend

Labour cost escalation

For the Revised Final Plan, we have applied a real labour cost escalation forecast averaging 0.9% per annum, consistent with the AER's Draft Decision.

In the Draft Decision, the AER applied an average of the annual forecasts for the real Wages Price Index (WPI) for the utilities industry (Electricity, Gas, Water and Waste Services (EGWWS)) by its consultant, Deloitte Access Economics and by our consultant (BIS Oxford Economics).[30]

This was a change on our approach in our Final Plan which took a weighted average of BIS Oxford Economics' annual forecasts for real WPI for the utilities industry and the real WPI for the construction industry, on the basis that labour costs in South Australia for AGN's gas distribution network are impacted by both industries' wages pressures. We had weighted the construction industry index at only 20%, ensuring the utilities industry index had stronger weighting (80%).

The AER stated that it did not include forecasts for the construction industry in its labour price growth forecasts, because the distribution of natural gas through mains systems is included in the

[30] AER, Draft Decision, Attachment 6, p. 26.

EGWWS industry under the Australian and New Zealand standard industrial classification. It stated that it is also consistent with the econometric studies it has used to test output and productivity growth.[31]

While we contend that the construction industry will still also have a bearing on wages pressure for network operations in South Australia, we have accepted that the AER's standard approach to forecasting labour price growth is to use an average of two WPI growth forecasts for the utilities industry based on one set of forecasts provided by the network (AGN), and one set from its own consultant.

Table 1.5 shows the updated calculation of annual real labour cost escalation based on the average of the respective consultants' forecasts.

Table1.5: Updated calculation of annual real labour cost escalation

Labour cost estimates	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
BIS Oxford Economics (BIS) Real WPI forecast	0.90%	0.90%	1.10%	1.30%	1.30%	0.90%
Deloitte Access Economics (DAE) Real WPI forecast	0.39%	0.66%	0.71%	1.00%	0.97%	0.39%
Average of BIS & DAE	**0.64%**	**0.78%**	**0.91%**	**1.15%**	**1.14%**	**0.64%**

Materials cost escalation

For our Revised Final Plan, we have continued to apply zero real cost escalation per annum to our materials costs, consistent with our approach in our Final Plan and recent regulatory decisions. The AER accepted this approach in its Draft Decision.

Weighting

We have adopted the AER's benchmark input price weightings of 62.0% labour and 38.0% materials, which were different to the weightings we had applied in the Final Plan (71.0% and 29.0% respectively) and further reduces the extent of price escalation assumed. The result is a weighted annual input cost escalation averaging 0.6% over the next AA period.

Table 1.6 shows our updated calculation of annual input cost escalation based on a weighted average of the labour and materials cost escalation outlined above.

[31] AER, Draft Decision, Attachment 3, p.p 13-14.

Table 1.6: Updated calculation of annual input cost escalation

Category	Weight	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
Labour	62.0%	0.64%	0.78%	0.91%	1.15%	1.14%	0.64%
Materials	38.0%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Annual input cost escalation		**0.62%**	**0.40%**	**0.48%**	**0.56%**	**0.71%**	**0.71%**

Output growth

We have updated the output growth factor over the next AA period to reflect updates in forecast growth in customer numbers and kilometres of mains in the network.[32] This update has resulted in an average output growth rate of negative 0.4% per annum over the next AA period, which is 0.7% lower than the rate applied in our Final Plan and approved by the AER in its Draft Decision (0.3%).

The change is driven by our adjusted demand forecasts with lower net connection growth expected over the next AA period, following the AEMC rule change for a new connection charge to be introduced.[33] The new connection charge will contribute to a contraction in connections and lower associated mains growth.

More information on the updates to demand forecasts including customer numbers, disconnections and kilometres of mains can be found in Attachments 13.1A, 13.2A and 13.4.

Table 1.7 shows the updated calculation of the output growth escalation factor.

Table 1.7: Updated calculation of the output growth escalation factor

Category	Weight	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
Customer numbers	50.6%	0.53%	-0.16%	-0.76%	-0.22%	-0.74%	-3.97%
Mains length km	49.4%	0.56%	0.46%	0.45%	0.36%	0.37%	0.32%
Annual input cost escalation		**0.55%**	**0.15%**	**-0.15%**	**0.07%**	**-0.18%**	**-1.84%**

Productivity growth

With network contraction now forecast over the next AA period and a reduction of 0.7% to the output growth forecast compared with our Final Plan and the AER's Draft Decision, we no longer consider that positive productivity growth is a reasonable assumption.

Although the AER's Draft Decision was to accept our proposed productivity growth factor of 0.4% per annum in our Final Plan, we have reset this to be zero in our Revised Final Plan. This is consistent with the AER-approved assumption of zero for productivity growth which is currently applied to our Victorian distribution network opex allowances, based on forecasts for network contraction over the AA period. Economies of scale are forecast to decline over the period, but AGN must still maintain

[32] See the Revised Opex Forecast Model at Attachment 8.1A for connection and mains length forecasts over the next AA period.
[33] AEMC, Rule determination - National Gas Amendment (Updating the regulatory framework for gas connections) Rule 2025, 11 December 2025.

a safe and reliable network. As the AER stated in its final decision for the current AA applying to the AGN network in Victoria:

> *… we note, due to forecasting negative output growth, we expect productivity to decline somewhat (by –0.2% per year) due to losses of economies of scale. This reflects that AGN will need to operate a safe and reliable network in line with its current regulatory obligations.*[34]

Trend rate of change

Based on the changes outlined above, we have applied a revised forecast average annual rate of change of just 0.2% which is summarised in Table 1.8 below.

Table 1.8: Opex trend annual rate of change

	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
Input prices	0.62%	0.40%	0.48%	0.56%	0.71%	0.71%
Output growth	0.55%	0.15%	-0.15%	0.07%	-0.18%	-1.84%
Productivity growth	0.40%	0.00%	0.00%	0.00%	0.00%	0.00%
Opex annual rate of change	**1.17%**	**0.55%**	**0.33%**	**0.64%**	**0.53%**	**-1.14%**

1.4.3 Step Changes

We are proposing five step changes to opex totalling $61.5 million in the next AA period, only $29.0 million or 47% of which result in an increase to total expenditure. Two of these step changes have been approved by the AER in its Draft Decision and are not discussed further in the next section:

1. Change in capitalisation policy ($32.5 million); and
2. IT application upgrades and enhancements ($4.1 million).

Three remaining step changes (for ICT non-recurrent costs for the transition, the cybersecurity uplift and a program of abolishments at redundant sites to ensure safety), which were not accepted by the AER as we proposed in our Final Plan, are discussed in the following sections.

Non recurrent ICT transition costs

Consistent with our Final Plan, we are proposing a step change for the non-recurrent opex we will incur in transitioning IT systems from APA to our environment. The transition has already commenced and therefore we are already incurring costs related to the project. With these costs available, as well as other updated information regarding the transition services provided by APA and timing of the project, we have revised our forecast for this step change from our Final Plan by a small ($0.5 million) amount to total $19.1 million.

In its Draft Decision, the AER was not satisfied that the proposed opex of $18.6 million, as per our Final Plan, would be prudent and efficient.[35] It questioned the prudency of the step change because it was uncertain as to the interaction and ownership of systems as between AGIG and AGN. It

[34] AER, AGN (Vic) 2023-28 - Final decision - Attachment 6 Operating expenditure - June 2023, p. 10.
[35] AER Draft Decision, Attachment 3, p. 20.

stated that it was this uncertainty which was central to its concerns about whether proposed costs are appropriately allocated to AGN as the regulated entity.[36]

It also considered that if the proposed expenditure was to be incurred by a prudent service provider acting efficiently, the costs would be similar to those incurred through AGN's contract with APA. The AER also was not satisfied that AGN provided sufficient information to support the proposed costs, including a supporting cost-benefit analysis, a proposed scope of work and the input rates, including labour rates and hours (which it found appeared high in the context).[37]

With a range of additional supporting information in this Revised Final Plan, we have sought to address these issues and provide evidence to the AER to demonstrate that:

- as a result of APA's exit from the networks operations business, the costs associated with the IT transition are unavoidable and are required in order to ensure the continued operation and management of services to AGN's customers;
- owners of critical infrastructure such as AGN are expected to control the systems and applications that are used to operate that critical infrastructure; and
- the transition costs relate only to systems used to operate and maintain the AGN networks, with costs then allocated between each of the networks owned by AGN.

Attachment 9.14 provides a response to the issues the AER has raised and explains the build-up, prudency and efficiency of the proposed IT expenditures, with section 3.3.4 of the Attachment 9.14 dealing with the operating expenditure forecast specifically. Attachments 9.15 and 9.17 provide further supporting information for the transition including on prudency and cost allocation matters.

As explained in our more detailed response on the need for the expenditure (Attachment 9.14), there is a one-off opex uplift in the next AA period associated with the transition services provided by APA during the period of the transition, in addition to a range of IT requirements: application licencing and production support, infrastructure, security and connectivity and IT support for the transitioned systems.

APA commenced providing the transition services on 1 December 2025, and will continue until the bulk of IT systems have successfully migrated across to AGN's technology environment under the 'lift and shift' activities of the transition.

In our forecast step change, we have also forecast annual costs for application licencing and production support, infrastructure, security and connectivity and IT support for the transitioned systems and subtracted the actual 2024/25 base year IT shared services costs (which will no longer be occurred).

Section 3.3.2 (Attachment 9.14) provides additional evidence that the assumed labour cost rates, which have informed the original KPMG modelling of opex requirements for the transition (and which the annual IT opex estimates are still based upon), are efficient based on a comparison of tender rates.

Compared with our Final Plan, we have also needed to adjust the timing for forecast application licencing and production support, infrastructure, security and connectivity and IT support opex

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[36] AER Draft Decision, Attachment 3, p. 20.
[37] Ibid.

under the IT Transition project, to reflect the project start date of 1 December 2025 (19 months earlier than our Final Plan proposal start date of 1 July 2027).

By year 4 of the regulatory period, the synergies from the merge phase of the transition are realised. The reduced ongoing operating costs of the AGN systems post 'merge' then continue beyond the next AA period, saving AGN SA customers an estimated minimum of $0.5 million per annum in perpetuity.

Cyber security

We propose the same step change of $1.2 million for an uplift to our cybersecurity capability, as we proposed in our Final Plan.[38] As a responsible pipeline operator, not only must we ensure the ongoing security of network assets, but that our data and our customers' data is secure. We provided a Business Case which demonstrated a risk-based program to target identified weaknesses in the IT operating environment and how we would address these cyber threats.[39] We also provided further detail in response to an AER information request about the cybersecurity proposal and costing for the step change.[40]

In its Draft Decision, the AER was not satisfied that these costs represent prudent and efficient expenditure.[41]

The AER was satisfied that AGN has prudently developed its cybersecurity maturity to date, including through a risk-based approach, and that it was further prudent for AGN to continue to invest and maintain its cybersecurity maturity in a growing threat environment, including to develop its capabilities to meet all new regulatory obligations.[42]

However, it suggested that the amount is already accounted for in AGN's base opex or the rate of change. Because of the small quantum of the expenditure proposed, the AER is concerned that the step change is a double counting of costs already provided through the base and trend factor as part of the base step trend approach to forecasting opex. It noted how the trend uplift is not solely for base activities but for continued growth and adaptation of the business over time.[43]

We agree that the trend factor is separate to the base year and is to cover growth: as a function of connection and mains length growth it is primarily to provide for incremental increases in operational costs incurred by the network due to growth. But this growth is mainly for expansion, and it is independent of expenditure driven by factors which are not linked to growth but instead are due to an uplift in service levels, new market conditions or additional customer need.

Regardless of any growth (noting we are not forecasting network growth in the Revised Final Plan), AGN would still require the additional expenditure on cybersecurity to address new risks to the business and the customer base from cyber threats. The cyber opex step change is also not covered by the base year forecast; it is to address identified weakness in our existing cybersecurity offering and fill gaps which our current spending levels do not cater for.[44]

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[38] AGN Final Plan, p. 88.
[39] Ibid.
[40] AGN, Response to AER Information Request No. 9 ('AGN Response to IR9')
[41] AER, Draft Decision, Attachment 3, p. 23.
[42] Ibid.
[43] AER, Draft Decision, Attachment 3, p. 23.
[44] AGN Final Plan, p. 88.

We seek to ensure that our opex forecasts are prudent and efficient. However, an assessment of prudency and efficiency should be contextual to the overall savings being accounted for in the opex forecast to ensure that AGN is still adequately compensated to fund the operational needs of the network. We submit that AGN should not be expected to absorb the proposed cybersecurity uplift as part of our opex proposal for the next AA period when:

- We have now forecast a contraction in customer numbers and slower growth in network length which results in a negative output growth forecast for the next AA period, largely as a result of the impending new connection charge. Therefore, there is no trend factor for growth and so no capacity under which to absorb additional efficient costs. That said, the net output growth allowance as part of the trend forecast should only cover additional efficient costs presented by the growth in customers and mains length, not uplifts in service levels or new network requirements.
- Updated estimates of real input cost escalation in our trend are now relatively low (averaging 0.2% per annum), despite continued labour market pressure on wages.
- The need for the cybersecurity step change is driven by the need to fill gaps in our current cybersecurity provision, and so the risk of a cybersecurity incident will increase if the initiatives are not implemented. The required expenditure is not included in the base year forecast. It requires an increase of around 52% on current annual cybersecurity expenditure, on average (based on 2024/25, the source of the base year forecast).[45]
- AGN has also already factored in significant opex savings to the opex forecast, as outlined in our Final Plan, with a number of forecast costs excluded.[46] The extent of these savings limits capacity to absorb more costs but these savings were not acknowledged by the AER in its Draft Decision. The savings include:
  - additional debt raising costs not covered by the AER benchmark (now estimated to be $4.6 million based on the 2024/25 actual debt raising costs and the AER's benchmark allowance in its Draft Decision);
  - rising insurance premium costs ($0.3 million),
  - additional networking monitoring costs ($1.0 million), and
  - additional costs for hazard testing, assessments and other operational work to help ready the network for renewable gas ($0.3 million), noting the AER has accepted the associated capex proposal.[47]
- The AER otherwise found AGN's proposed investment in cybersecurity and the risk-based program of initiatives to be prudent.[48]

The fact that the request is relatively small for the cybersecurity step change should not be reason enough to not accept it. On the contrary, the amount reflects how AGN has been targeted and efficient in estimating the amount of additional expenditure required to address gaps in cybersecurity. It also reflects how we have demarcated cybersecurity from other IT needs to help assess the expenditure requirements in this area, as well as ensuring AGN focuses on the specific

[45] AGN, Response to AER Information Request No. 9 and AGN calculations.
[46] AGN Final Plan, pp. 91-92.
[47] AER, Draft Decision, Attachment 2, pp 10-11.
[48] AER, Draft Decision, Attachment 3, p. 23.

need for cybersecurity steps for customers and the business, but it should not be viewed as immaterial because of this separation.

For these reasons, we request that the AER accept the proposed step change of $1.2 million for critical cybersecurity needs.

Abolishments for safety at redundant sites

Our Revised Final Plan continues to seek a step change of $4.6 million for abolishments at redundant sites to address safety risk, as proposed in our Final Plan.[49] In our Final Plan, we stated how there is a need to permanently remove service line from 3,500 redundant 'inlet only' services on our network, over the next AA period. These residential services have a live supply to the metering location, including a vertical standpipe, but no meter in place. This situation arises when meters are removed due to billing issues, renovations or construction work, and a new meter is not re-installed.[50]

We also explained how the sites we identified are locations that have not had gas meters for over 24 months. This time period ensures that no inlets are included where customers are simply waiting for a meter fix. It also means that the customer is not using gas and so they may not be aware that they have live gas assets on their property. Importantly, keeping the inlet in service unnecessarily exposes it to the risk of damage from third party work and potential leak and ignition.[51]

To eliminate this risk, we need to implement a proactive program aimed at removing these redundant services within a reasonable timeframe. Our goal is to address the backlog over a five-year period, at a rate of 700 services per year. Our assumed unit rate for abolishment in SA is $1,250.[52]

In its Draft Decision, the AER did not accept the proposed expenditure as part of the opex forecast.[53] The AER cited several concerns with this proposed step change and considered that AGN did not provide sufficient information or analysis to demonstrate that the proposed costs are required to address a safety issue. Its main concerns (and where we have addressed them in our Revised Final Plan) are that:

- There is no regulatory obligation to remove redundant services (addressed in Section 1.2.1 of Attachment 8.6)
- AGN did not provide evidence of any incidents involving redundant services (Section 1.2.2)
- AGN did not provide evidence of an increased risk if redundant services are not abolished (Section 1.2.2)
- AGN did not demonstrate that it had considered other options to address this risk, or analysis showing the proposed approach to be the best option (Section 1.2.2.1)
- AGN did not provide a basis for the proposed 24-month period for a service to be deemed redundant (Section 1.2.3)

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49 AGN Final Plan, p. 88.
50 Ibid.
51 Ibid.
52 Attachment 8.6, Section 1.2.4.
53 AER, Draft Decision, Attachment 3, pp. 22-23.

- It is likely that some customers with a dormant connection would value that connection in the future, and consequently, not every connection would need to be removed (Section 1.2.3)
- AGN did not provide evidence that it sought, or received, advice from the Office of the Technical Regulator (OTR), the relevant safety regulator, on the need for this program (Section 1.2.1).[54]

We maintain the need for the program of work and have responded to each of these concerns directly in Attachment 8.6 of this Revised Final Plan in various sections as indicated above.

We have discussed information about the regulatory obligation in South Australia to conduct the works and note the Energy Safe Victoria (ESV) position that abolishment of services is required in these circumstances to address safety risk.[55] The OTR has advised AGN of its support for the works in principle, on safety grounds.[56] Clearly, if we do not undertake the program of work, AGN risks not meeting its regulatory obligations regarding maintaining safety of the network.

We have provided evidence of the incidents that occur with a redundant site connection still in place, further demonstrating the safety risk involved in leaving pipelines underground at these sites.[57]

We understand that the AER is aware of the safety risk presented by redundant sites with unused gas connections, as it advised in its AEMC submission on the regulatory framework regarding disconnections the following:

> *Either of those approaches leaves live gas connection pipes under customer properties and sometimes leaves gas within customer premises, giving risk of inadvertent gas leaks via strikes on connection pipes or other events.*[58]

and:

> *We consider that the sector, relevant regulators and governments should investigate alternatives to loading additional costs on to remaining gas customers, while also effectively managing the safety risk associated with live but unused gas connections remaining in situ.*[59]

We have considered the other options to address the risk[60], but the service abolishment is the most effective and prudent risk mitigation approach from an operational perspective. Further, the alternatives considered are complementary to abolishment and not necessarily a substitute for permanently removing the service. On safety grounds, we must start abolishing redundant services where it is clear there is no longer a need for them.

In addition, we have explained how we would check with customers before undertaking the work, although it is unlikely that a customer will still value the connection.[61] If an abolishment is not

[54] AER, Draft Decision, Attachment 3, p. 22.
[55] Attachment 8.6, Section 1.2.1.
[56] Attachment 8.6, Section 1.2.1. OTR, Email to AGN, 16 December 2025.
[57] Attachment 8.6, Section 1.2.2. We have showed that 18% of third-party asset strikes in 2023 occurred on sites without meters present, and the share was 11% in 2024, together accounting for 112 strikes in total for the AGN SA network.
[58] AER, Submission to the AEMC review on updating the regulatory framework, 10 July 2025, p. 4.
59 Ibid.
[60] Attachment 8.6, Section 1.2.2.1.
[61] Attachment 8.6, Section 1.2.3.

necessary because the customer indicates it wishes to retain the service, there are other sites that are likely to become redundant over the 5-year period to fill the gap..

We acknowledge the questions about the chosen timeframe of 24 months for these redundant sites by both the AER and the OTR.[62] It should be recognised that the 24-month mark (from date of meter removal) is just a threshold for identification of sites. Some sites identified for abolishment as part of this program have been redundant for longer than 24 months and virtually all sites would be redundant by up to around 8 years or longer by the end of the AA period if the gas lines at the site are not permanently abolished.[63] We have explained further the reasonableness of the threshold of 24 months to identify sites in Attachment 8.6.[64]

For these reasons, we request that the AER reconsider its position in its Draft Decision concerning the need for the abolishments of redundant sites with the additional evidence we have provided. Accordingly, we have included the opex step change of $4.6 million in our Revised Final Plan opex forecast.

1.4.4 Category specific forecasts

We propose category specific forecasts for unaccounted for gas (UAFG) and debt raising costs. We accept the AER's draft decision on debt raising costs (based on its standard benchmark approach)[65] but seek to modify the AER's position on UAFG forecasts concerning the price assumption, as discussed below.

Unaccounted for Gas (UAFG) forecasts

We are forecasting $19.7 million in UAFG costs over the next AA period, an increase of $5.1 million (or 35%) on the amount allowed for by the AER's Draft Decision ($14.6 million)[66] but a decrease of $8.2 million (or 29%) from our Final Plan ($27.9 million)[67].

Our Revised Final Plan forecast for UAFG expenditure incorporates changes to both the assumed volume and price over the next AA period, compared with our Final Plan, where our forecast was the product of:

- the annual average volume of UAFG in the last 3 years based on settled UAFG volumes for 2020/21, 2021/22 and 2022/23, and

  1. the forecast average price of UAFG based on available market information, with evidence of another recent UAFG contract entered into by AGN interstate provided confidentially to the AER to support the assumed price.[68]

In its Draft Decision, the AER adjusted the forecast volume by including the unsettled UAFG volume data for 2023/24 in the 3-year average[69]. The AER agreed that the downward trend observed from settled volumes of UAFG over the past 6 years reflects AGN's mains replacement program (MRP),

[62] AER, Draft Decision, Attachment 3, p. 22 and OTR, Email to AGN, 16 December 2025.
[63] The sites were identified in 2025 as at end 2024.
[64] Section 1.2.3, pp. 8-9.
[65] AER, Draft Decision, Attachment 3, p. 25.
[66] Ibid.
[67] AGN Final Plan, p. 90.
[68] AGN Final Plan, p. 90 and AGN, (Confidential) Response to AER IR#002, 13 August 2025.
[69] It based the 3-year average on settled data for 2021/22 and 2022/23 and unsettled data for 2023/24.

and that the downward trend is likely to continue given that AGN is conducting further (though much less) MRP work.[70]

While we remain cautious about relying on unsettled UAFG data (which can still change before it is settled), we accept the AER's adjusted volume forecast for the next AA period.

Regarding the forecast price for UAFG, the AER did not accept the market-based forecast we made in our Final Plan because it was not based on a commercial contract specifically for the South Australian distribution network. It stated that the price is significantly higher than the wholesale gas price projections prepared by ACIL Allen for AEMO's 2025 Gas Statement of Opportunities (GSOO) and adopted those forecasts instead.[71]

However, the GSOO wholesale gas prices is not a reasonable basis upon which to forecast the UAFG commercial price outcome and these prices are lower than UAFG prices. The wholesale gas price does not include any distribution costs or retailer margin for UAFG (as ACIL Allen advised in its projections)[72] and does not reflect commercial outcomes arising from the willingness and capacity for provision of UAFG by a retailer, specific to the needs of the network.

As noted by the AER in its Draft Decision, there will continue to be a true-up factor in the tariff variation mechanism for the price of gas assumed in the forecast,[73] but the price of UAFG assumed must still be reasonable in the circumstances and based on a prudent and efficient forecast.

We have since received commercial pricing information specific to provision of UAFG over the next AA period (2026/27 to 2030/31) for the AGN SA network, which we have provided at Confidential Attachment 8.7 to support the price forecast we have incorporated in our revised UAFG expenditure forecast. This assumed price reflects a small revision to our UAFG price forecast in our Final Plan.

As stated above, our adjusted volume and price assumptions result in forecast UAFG expenditure of $19.7 million over the next AA period, which is $5.1 million higher than the Draft Decision.

1.5 Summary

Our Revised Final Plan opex forecast for the next AA period is $434.0 million, which is $37.8 million higher than the AER's Draft Decision. Our revised opex forecast incorporates feedback from our customers and stakeholders and reflects the AER's preferred approach, wherever possible.

A summary of our revised opex forecast is provided in Table 1.9 below.

Table 1.9: Revised Final Plan opex forecast summary ($ million, June 2026)

Cost	2026/27	2027/28	2028/29	2029/30	2030/31	Total
Base year opex forecast	68.7	68.7	68.7	68.7	68.7	343.3
Step changes (excluding change in capitalization)	12.7	6.3	6.0	2.4	1.5	29.0
Change in capitalization	6.4	7.0	6.3	6.6	6.2	32.5

[70] AER, Draft Decision, Attachment 3, p. 26.
[71] AER, Draft Decision, Attachment 3, p. 26 and AGN calculations.
[72] ACIL Allen, *Gas, liquid fuel, coal and renewable gas projections – Final report*, p. 1 at https://aemo.com.au/-/media/files/major-publications/isp/2025/acil-allen 2024-fuel-price-forecast-report.pdf
[73] AER, Draft Decision, Attachment 3, p. 25.

Trend	0.4	0.6	1.0	1.4	0.6	4.0
UAFG	3.7	3.8	4.0	4.1	4.2	19.7
Total opex forecast (ex. DRC)	91.8	86.4	86.0	83.1	81.1	428.5
Debt raising costs (DRC)	1.1	1.1	1.1	1.1	1.1	5.5
Total opex forecast (inc. DRC)	**92.9**	**87.5**	**87.1**	**84.2**	**82.3**	**434.0**
Ancillary Reference Service	6.1	8.0	8.8	11.4	15.5	49.9
Total opex (inc. DRC and ARS)	**99.0**	**95.5**	**95.9**	**95.7**	**97.8**	**483.9**