Draft decision

Australian Gas Networks (SA) access arrangement 2026 to 2031

(1 July 2026 to 30 June 2031)

Attachment 3 – Operating expenditure

November 2025

AUSTRALIAN ENERGY REGULATOR

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Version	Date	Pages
1	28 November 2025	32

List of attachments

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

The draft decision includes the following documents:

Overview

Attachment 1 – Capital base, Regulatory depreciation and Corporate income tax

Attachment 2 – Capital expenditure

Attachment 3 – Operating expenditure

Attachment 4 – Demand

Attachment 5 – Reference services, tariffs and non-tariff components

- Includes: Services covered by the access arrangement, reference tariff settings, reference tariff variation mechanism, and non-tariff components

Attachment 6 – Capital expenditure sharing scheme

Attachment 7 – Efficiency carryover mechanism

Contents

3 Operating expenditure

Operating expenditure (opex) is the operating, maintenance and other non-capital expenses, incurred in the provision of pipeline services. Forecast opex is one of the building blocks we use to determine a service provider's total revenue requirement.

In this attachment, we outline our assessment of AGN SA's (AGN) opex proposal for the 2026–31 access arrangement period (2026–31 period).

3.1 Draft decision

Our draft decision is to not accept AGN's total forecast opex of $464.1 million ($2025–26)[1] for the 2026–31 period, excluding ancillary reference services and including debt raising costs. This is because we are not satisfied that AGN's total forecast opex reasonably reflects the opex criteria[2] and the requirements for forecasts and estimates.[3]

Our draft decision is to include our alternative estimate of total forecast opex of $396.2 million for the 2026–31 period, which is:

- $67.9 million (–14.6%) lower than AGN's total forecast opex proposal
- $41.1 million (–9.4%) lower than the opex forecast we approved for the 2021–26 access arrangement period (2021–26 period)
- $43.0 million (12.2%) higher than AGN 's actual (and estimated) opex in the 2021–26 period.

Table 3.1 sets out AGN's opex proposal, our alternative estimate for the draft decision and the differences.

1 All numbers are in $2025–26, unless otherwise indicated.

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

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

Table 3.1 Comparison of AGN's opex proposal and our alternative estimate ($million, 2025–26)

	AGN's proposal	AER alternative estimate	Difference
Based on estimated opex in 2024–25	**368.7**	**365.6**	**–3.0 (–0.7%)**
2024–25 to 2025–26 increment	**3.9**	**4.4**	**0.4 (0.1%)**
Remove category specific forecasts	**–33.9**	**–34.0**	**–0.1 (–0.0%)**
Trend: Output growth	2.9	2.8	–0.1 **(–0.0%)**
Trend: Price growth	7.2	5.2	–2.0 **(–0.4%)**
Trend: Productivity growth	–4.2	–4.0	0.2 **(0.0%)**
Total trend	**5.9**	**4.0**	**–1.9 (–0.4%)**
Step change: Purchase of renewable gas guarantee of origin certificates	26.0	–	–26.0 **(–5.6%)**
Step change: Overheads to be expensed (capex to opex)	32.0	32.0	–
Step change: Transition from APA – AGN IT costs	18.5	–	–18.5 **(–4.0)**
Step change: Cybersecurity (Data privacy/security & Access control)	1.2	–	–1.2 **(–0.3%)**
Step change: Application upgrades & enhancements	4.1	4.1	–
Step change: Abolishments for safety at redundant sites	4.6	–	–4.6 **(–1.0%)**
Total step changes	**86.5**	**36.1**	**–50.3 (–10.8%)**
Category specific forecasts	27.9	14.6	–13.2 **(–2.9%)**
Total opex, excluding debt raising costs	**458.9**	**390.7**	**–68.2 (–14.7%)**
Debt raising costs	5.1	5.5	0.3 **(0.1%)**
Total opex, including debt raising costs	**464.1**	**396.2**	**–67.9 (–14.6%)**

Source: AGN SA, *Attachment 8.1_Opex Forecast Model,* 1 July 2025; AER analysis.
Note: Numbers may not add up to total due to rounding. Amounts of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

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

- not included 4 step changes that we consider are either already accounted for elsewhere in the total opex forecast, or where AGN has not provided sufficient information to demonstrate the prudency and efficiency of the proposed amounts:

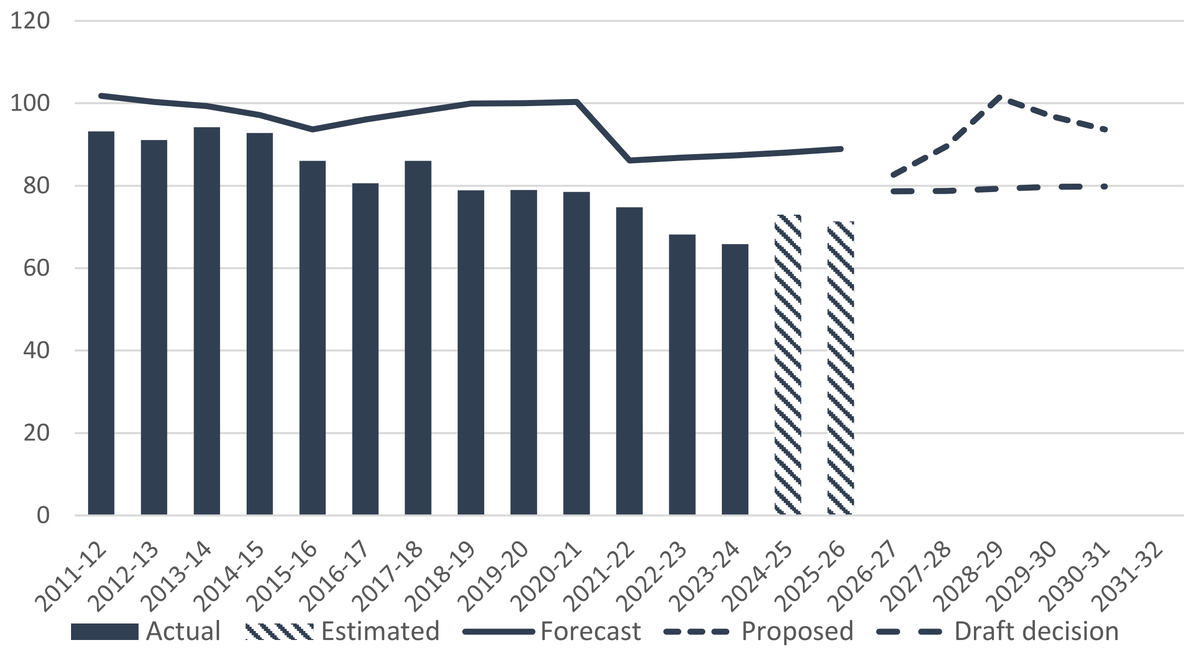
 - Cyber security (section 3.5.3.5)
 - Purchase of renewable gas guarantee of origin certificates (section 3.5.3.2)
 - Non-recurrent IT transition costs (section 3.5.3.3)
 - Abolishments for redundant sites (section 3.5.3.4)

- adjusted forecast Unaccounted for Gas (UAFG) costs to reflect benchmark wholesale gas prices reported in AEMO's 2025 Gas Statement of opportunities (section 3.5.4.2).

We have also applied minor mechanical input updates for price growth (e.g., wage price index forecasts) and a more recent inflation forecast from the Reserve Bank of Australia (RBA).[4]

In Figure 3.1, we compare our alternative estimate of total forecast opex to AGN's proposal for the 2026–31 period. We also show the forecasts we approved for the last 2 access arrangement periods, and AGN's actual and estimated opex over these periods.

Figure 3.1 Historical and forecast opex ($million, 2025–26)



Source: AGN SA, *Regulatory accounts*, 2011 to 2026; AGN SA, *Attachment 8.1_Opex Forecast Model, ,* 1 July *2025*; AGN SA, *Access arrangement, PTRM (multiple periods*: 2011–16, 2016–21, 2021–26); AER analysis.

Note: Includes debt raising costs and movements in provisions.

We discuss the difference between our alternative estimate and AGN's proposal in detail in section 3.5.

[4] Reserve Bank of Australia, *Statement on Monetary Policy*, August 2025, (https://www.rba.gov.au/publications/smp/2025/aug/outlook.html#3-5-detailed-forecast-information).

3.2 AGN's proposal

AGN applied a 'base-step-trend' approach to forecast opex, consistent with our preferred approach.[5]

AGN proposed total forecast opex of $464.1 million. AGN:[6]

- used an opex estimate for 2024–25 as the base from which to forecast (its estimate of $73.7 million in the base year contributes $368.7 million to the total forecast opex)
- removed $33.9 million for costs that it forecast on a category specific basis
- added $3.9 million for the final year increment (from 2024–25 to 2025–26)
- applied a rate of change comprising:
  - output growth ($2.9 million)
  - price growth ($7.2 million)
  - productivity growth (–$4.2 million)
- added 6 step changes totalling $86.5 million for:
  - Change in capitalisation policy – Overheads ($32.0 million)
  - Purchase of Renewable Gas Guarantee of Origin Certificates ($26.0 million)
  - Non-recurrent IT transition costs ($18.5 million)
  - Abolishment of redundant sites ($4.6 million)
  - Application upgrades and enhancements ($4.1 million)
  - Cybersecurity ($1.2 million)
- added 2 category specific forecasts, totalling $33.0 million for:
  - UAFG ($27.9 million)
  - debt raising costs ($5.1 million).

Figure 3.2 shows the different components that make up AGN's proposed total forecast opex.

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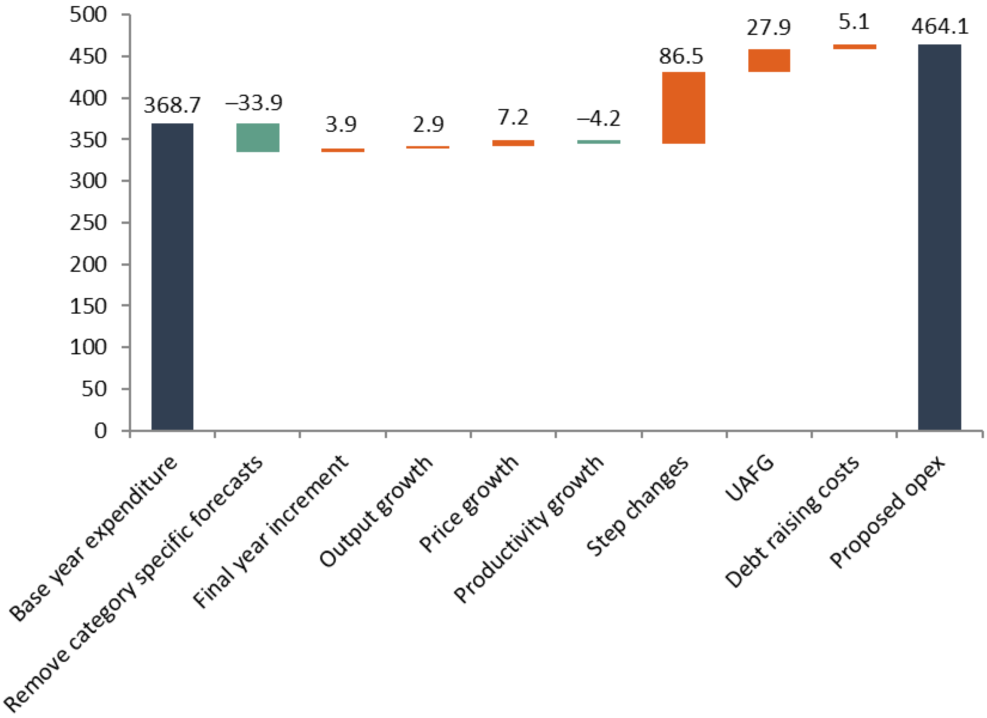
5 AGN SA, *2026–2031 Final plan*, 11 July 2025, p. 79.

6 AGN SA, *Attachment 8.1_Opex Forecast Model*, 1 July 2025.

Figure 3.2 AGN's proposed opex ($million, 2025–26)



Source: AGN SA, *Attachment 8.1_Opex Forecast Model*, 1 July 2025; AER analysis.

AGN's proposed total forecast opex of $464.1 million is $110.9 million (31.4%) higher than its actual and estimated opex over the 2021–26 period.

3.3 Assessment approach

Our role is to decide whether or not to accept a business's forecast opex. We approve the business's forecast opex if we are satisfied that it meets the opex criteria. The opex criteria require that:

> Operating expenditure must be as such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.[7]

In deciding whether forecast opex meets the opex criteria, we also apply the forecasting and estimate requirements under the National Gas Rules (NGR), which include that:

> A forecast or estimate must be arrived at on a reasonable basis and must represent the best forecast or estimate possible in the circumstances. [8]

7 NGR, r. 91(1). Rule 91(2) also provides that the forecast of required operating expenditure of a pipeline service that is included in the full access arrangement must be for expenditure that is allocated between reference services in accordance with Rule 93.

8 NGR, r. 74(2).

We use a form of incentive based regulation to assess the business's forecast opex over the access arrangement period at a total level. To do so, we develop an alternative estimate of total opex using a 'top-down' forecasting method, known as the 'base–step–trend' approach.[9]

Once we have developed our alternative estimate of total forecast opex, we compare it with the business's total forecast opex to form a view on the reasonableness of the business's proposal. If we are satisfied the business's total forecast meets the NGR requirements, we accept the forecast. If we are not satisfied, we substitute the business's forecast with our alternative estimate.

In making this decision, we take into account the reasons for the difference between our alternative estimate and the business's forecast, and the materiality of that difference. We also take into consideration the interrelationships between the opex forecast and other constituent components of our decision, such that our decision is likely to contribute to the achievement of the National Gas Objective (NGO).[10]

3.3.1 Incentive regulation and the 'top-down' approach

Incentive regulation is designed to prevent network businesses from exploiting their natural monopoly position by setting prices in excess of efficient costs. A key feature of the regulatory framework is that it is based on incentivising networks to be as efficient as possible. We apply incentive-based regulation across the energy networks we regulate, including gas networks. More specifically for opex, we rely on the efficiency incentives created by both ex-ante revenue regulation (where forecast opex is approved over a multi-year regulatory period) and the efficiency carryover mechanism (ECM).[11]

The incentive-based regulatory framework partially overcomes the information asymmetries between the regulated businesses and us.[12] It is intended to align the commercial goals of the network businesses to the objectives of the regulatory regime—especially the long-term interests of consumers (a key consideration under the NGO).[13]

Incentive regulation aligns these goals by encouraging regulated businesses to reduce costs below our forecast, in order for them to make higher profits, and 'reveal' their costs in doing so. The information revealed by the businesses allows us to develop better expenditure

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9 A 'top-down' approach forecasts total opex at an aggregate level, rather than forecasting all individual projects or categories to build a total opex forecast from the 'bottom up'.

10 National Gas Law (NGL), s. 28(1)(a). The NGO is set out in s. 23 of the NGL.

11 The approach we apply to assessing a business's opex (and which we have applied in this decision) is more fully described in the *Expenditure Forecast Assessment Guideline* and its accompanying explanatory materials, which are published on the AER's website.

12 Productivity Commission, *Electricity Network Regulatory Frameworks*, volume 1, No. 62, 9 April 2013, p. 189.

13 The NGO is set out in the s. 23 of the NGL. The NGO is '...to promote efficient investment in, and efficient operation and use of, covered gas services for the long term interests of consumers of covered gas with respect to—

(a) price, quality, safety, reliability and security of supply of covered gas; and

(b) 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.

forecasts over time. Revealed opex reflects any efficiency gains made by a business over time. As a network business becomes more efficient, this translates to lower forecasts of opex in future access arrangements, which means consumers also receive the benefits of the efficiency gains made by the business. Incentive regulation therefore aligns the business's commercial interests with consumer interests.

The Productivity Commission explains:

> Under incentive regulation, the regulator forecasts efficient aggregate costs over the upcoming regulatory period (of usually 5 years), which it uses to set a revenue allowance for that period. The business makes higher profits if it reduces costs below those forecast by the regulator. In doing so, the business reveals the efficient costs of delivering the service, which would then influence the regulator's determination in the next period. Accordingly, incentive regulation encourages efficiency while reducing the risks that networks use their monopoly positions to set unreasonably high prices.[14]

Incentive regulation is designed to leave the day-to-day decisions to the network businesses.[15] It allows the network businesses the flexibility to manage their assets and labour as they see fit to comply with the opex criteria and achieve the NGO.

Our general approach is to assess whether opex, in aggregate, is sufficient to satisfy the opex criteria over the access arrangement period (the 'top-down' approach), rather than to assess all individual opex projects or programs (the 'bottom-up' approach). As noted above, to do so, we develop an alternative estimate of total opex using the 'base–step–trend' forecasting approach (section 3.3.2). This is generally a 'top-down' approach, but there may be circumstances where we need to use 'bottom-up' analysis, particularly in relation to our base opex assessment and for step changes.

3.3.2 Building an alternative estimate of total forecast opex

As a comparison tool to assess a business's forecast opex, we develop an alternative estimate of the business's total opex requirements in the forecast period, using the base–step–trend forecasting approach. We apply the forecasting and estimate requirements under the NGR.

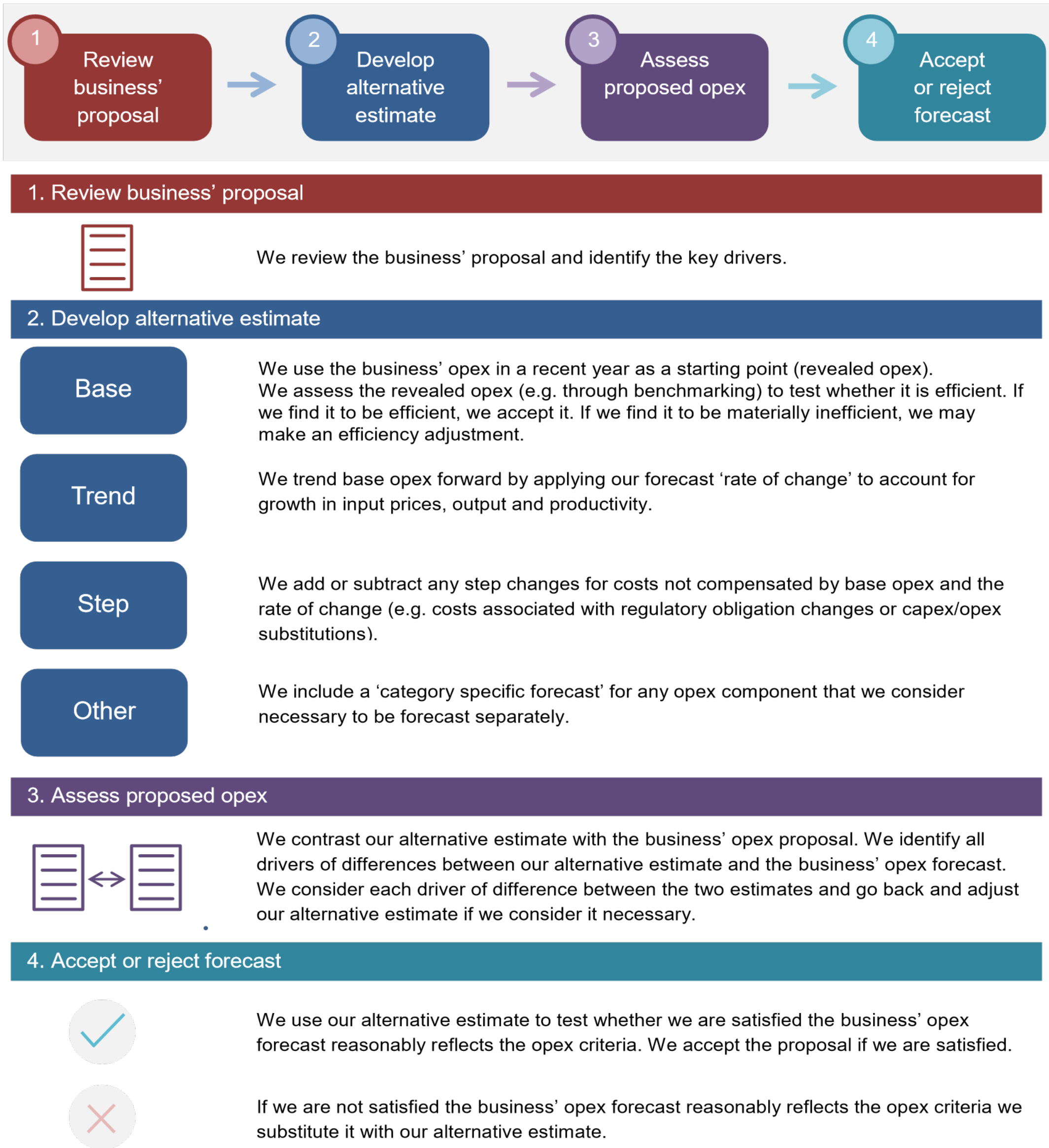
If a business adopts a different forecasting approach to derive its opex forecast, we develop an alternative estimate and assess any differences with the business's forecast opex.

Figure 3.3 summarises the base-step-trend forecasting approach:

14 Productivity Commission, *Electricity Network Regulatory Frameworks*, volume 1, No. 62, 9 April 2013, p. 27.

15 Productivity Commission, *Electricity Network Regulatory Frameworks*, volume 1, No. 62, 9 April 2013, pp. 27–28.

Figure 3.3 Our opex assessment approach



3.3.3 Interrelationships

In assessing AGN's total forecast opex, we also take into account other components of the access arrangement proposal that could interrelate with our opex decision. The matters we considered in this regard included:

- the ECM carryover—the level of opex used as the starting point to forecast opex (the final year of the 2021–26 period) should be the same as the level of opex used to calculate ECM carryovers. This consistency ensures that the business is rewarded (or penalised) for any efficiency gains (or losses) it makes in the final year the same as it would for gains or losses made in other years
- the operation of the ECM in the 2021–26 period, which provided AGN an incentive to reduce opex in the base year
- our assessment of forecast demand growth, including AGN's forecast growth in customer numbers and mains length, which we have used to forecast output growth and UAFG

- the impact of cost drivers that affect both forecast opex and forecast capital expenditure (capex). For instance, forecast labour price growth affects forecast capex and our forecast price growth used to estimate the rate of change in opex
- the approach to assessing the rate of return, to ensure there is consistency between our determination of debt raising costs and the rate of return building block
- the outcomes of AGN's engagement with consumers and stakeholders in developing its proposal.

3.4 Submissions on the proposal

We received 4 submissions on AGN's proposal relating to opex.

The South Australian Council of Social Services (SACOSS) raised concerns on the viability of a hydrogen future, including noting that residential and low-income consumers should not bear the risks and costs that AGN is more appropriately placed to manage itself. This especially related to AGN's 'Purchase of renewable gas guarantee of origin certificates' step change proposal.[16]

Energy Consumers Australia raised similar concerns on hydrogen, and submitted that it did not support the proposed 'Purchase of renewable gas guarantee of origin certificates' step change.[17]

The South Australian Reference Group Review Panel noted that the AER was best placed to assess the proposed base year and unaccounted for gas proposal, but highlighted that it also did not support the 'Purchase of renewable gas guarantee of origin certificates' step change.[18]

The Consumer Challenge Panel, Sub-panel 33 (CCP33) commended AGN for its work to support customers experiencing hardship, but also questioned the reasonableness of AGN's trend forecasts given the uncertainty in the future of gas.[19] Consistent with other stakeholders, CCP33 also stated that it does not support the Purchase of renewable gas guarantee of origin certificates,[20] and also questioned the benefits of AGN's proposed ICT investments to all customers.[21]

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16 SACOSS, *Submission on AGN SA 2026–31 Access arrangement proposal*, August 2025, pp. 3–5.

17 Energy Consumers Australia, Submission on AGN SA and Evoenergy *2026–31 Access arrangement proposal*, August 2025, pp. 3–4.

18 South Australian Reference Group Review Panel, *Submission on AGN (SA) 2026–31 Access arrangement proposal, August 2025*, pp. 6, 25–26.

19 CCP33, *Advice to AER – Submission on AGN (SA) 2026–31 Access arrangement proposal*, August 2025, pp. 32–33.

20 CCP33, *Advice to AER – Submission on AGN (SA) 2026–31 Access arrangement proposal*, August 2025, pp. 32–33.

21 CCP33, *Advice to AER – Submission on AGN (SA) 2026–31 Access arrangement proposal*, August 2025, p. 33.

3.5 Reasons for the draft decision

We do not accept AGN's proposed opex forecast of $464.1 million for the 2026–31 period,[22] because we are not satisfied that it reflects the opex criteria[23] and the requirements for forecasts and estimates.[24]

Our draft decision is to include a total opex forecast of $396.2 million, excluding ancillary reference services and including debt raising costs. This is $67.9 million (–14.6%) lower than AGN's proposed forecast opex of $464.1 million.[25] We are satisfied our alternative estimate of total forecast opex for AGN reasonably reflects the opex criteria and the forecasts and estimates criteria in the NGR.[26] We also consider that our alternative estimate provides a total forecast opex such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.

Table 3.1 sets out AGN's proposal, our alternative estimate that is the basis for the draft decision, and the difference between our draft decision and the proposal.

We have set out the main drivers for the differences in section 3.1, and we discuss the components of our alternative estimate, and our assessment of AGN's proposal, below. Full details of our alternative estimate are set out in our opex model, which is available on our website.

3.5.1 Base opex

This section provides our view on the prudent and efficient level of base opex that we consider AGN needs for the safe and reliable provision of services.

We have used 2024–25 as the base year, which is consistent with AGN's proposed base year. However, we have used a base year opex estimate of $73.1 million, or $365.6 million over 5 years (excluding ancillary reference services), to form our alternative estimate of total forecast opex. This is slightly lower than AGN's proposal of $73.7 million, or $368.7 million over the 2026–31 period (excluding ancillary reference services).[27] This is because we have applied a more recent inflation forecast from the RBA.[28]

AGN stated that its base year estimated opex reflects 9 months of actual data and 3 months of forecasts. This amount will need to be updated following our draft determination to reflect the full actual costs incurred in 2024–25. [29] This will reflect opex in the most recent year for which audited actual data is available by the time of us making our final determination.

22 AGN SA, *Attachment 8.1_Opex Forecast Model*, 1 July 2025.

23 NGR, r. 91.

24 NGR, r. 74.

25 AGN SA, *Attachment 8.1_Opex Forecast Model*, 1 July 2025.

26 NGR, r. 91; NGR, r. 74.

27 AGN SA, *Attachment 8.1_Opex Forecast Model*, 1 July 2025.

28 RBA, *Statement on Monetary Policy*, August 2025, (https://www.rba.gov.au/publications/smp/2025/aug/outlook.html#3-5-detailed-forecast-information).

29 AGN SA, *2026–2031 Final plan*, 11 July 2025, p. 85.

AGN stated that the base year opex can be assumed to be both prudent and efficient given the operation of both:

- the opex incentive scheme, the objective of which is to provide a continuous incentive to pursue efficiencies and achieve the lowest sustainable cost of providing services in every year; and
- its internal and external controls on asset management, procurement and financial governance, the objectives of which are to ensure AGN undertakes opex in a prudent and efficient manner, in accordance with good industry practice.[30]

AGN did not provide any economic benchmark report showing the analysis of its opex efficiency in the proposed base year. We do not undertake our own economic benchmarking or category analysis review of gas distributors to assess the efficiency of the base year opex. Historically, we have relied on the economic benchmarking undertaken by the gas network businesses.

We have reviewed AGN's actual opex. Figure 3.1 shows that AGN's opex has decreased by 21% between 2013–14 and 2023–24, and it is expected to decrease further in 2024–25, from its 2013–14 level. We agree with AGN that through the application of the ECM, it has been subject to a continuous incentive to pursue efficiencies and achieve the lowest sustainable cost of providing services in every year. While the estimated opex in 2024–25 and 2025–26 appears expected to be higher than actual opex in the first 3 years of the 2021–26 period, it remains lower than forecast opex for that year and across the period. AGN does not have an incentive to increase its opex above efficient levels in the proposed base year.[31]

In summary, we have not identified any evidence that AGN's proposed 2024–25 base year is materially inefficient. We consider it to be an appropriate choice of base year.

We have not applied any efficiency adjustment to base year opex, in line with AGN's proposal.

3.5.1.1 Removal of category specific forecasts

In some circumstances, we remove a category of opex from the base year expenditure if it is more appropriate to forecast that category separately. We refer to these as 'category specific forecasts' (see section 3.5.4).

We have removed UAFG and debt raising costs from base opex, to be forecast separately. This is consistent with our standard approach, as well as AGN's proposal.

Accordingly, we have removed $34.0 million from base opex for the costs we forecast as category specific forecasts. This is slightly higher than the $33.9 million that AGN removed because we applied a more recent inflation forecast, which was not available at the time of AGN's proposal.

30 AGN SA, *2026–2031 Final plan*, 11 July 2025, p. 85.

31 NGR, r. 71(1).

3.5.1.2 Final year increment

Our standard approach to estimating final year opex is to add the forecast change in opex between the base year (2024–25) and the final year (2025–26) to the base year opex amount.[32] This ensures that our estimate of opex in the final year that we use to forecast opex for the 2026–31 period is consistent with the estimate in the ECM (the ECM uses the same equation to estimate opex in the final year). This ensures that AGN is only rewarded for efficiency gains passed on to consumers through a lower opex forecast, or only penalised for efficiency losses that are reflected in forecast opex.

We have included $4.4 million for the final year increment in our alternative estimate, which is more than AGN's proposed amount of $3.9 million. The variance between our estimate of the final year increment and AGN's proposal arises because AGN used a different approach to forecast the change in opex between the base year and the final year. It applied the forecast rate of change from the base year (rather than from the final year).

3.5.2 Rate of change

Having estimated opex in the final year of the 2021–26 period, we then applied a forecast annual rate of change to forecast opex for the 2026–31 period. We have applied an average annual rate of change of 0.5% to derive our alternative estimate of opex. This is lower than the average of 0.7% that AGN used. We compare both sets of forecasts in Table 3.3.

Table 3.2 Forecast annual rate of change in opex, %

	2026–27	2027–28	2028–29	2029–30	2030–31
AGN's proposal					
Forecast output growth	0.2	0.1	0.5	0.4	0.3
Forecast price growth	0.6	0.6	0.8	0.9	0.9
Forecast productivity growth	0.4	0.4	0.4	0.4	0.4
Forecast rate of change	**0.4**	**0.4**	**0.9**	**0.9**	**0.8**
AER alternative estimate					
Forecast output growth	0.2	0.1	0.5	0.4	0.3
Forecast price growth	0.4	0.5	0.6	0.7	0.7
Forecast productivity growth	0.4	0.4	0.4	0.4	0.4
Forecast rate of change	**0.2**	**0.2**	**0.7**	**0.7**	**0.6**

Source: AGN SA, *Attachment 8.1_Opex Forecast Model*, July 2025; AER analysis.
Note: The rate of change = (1 + price growth) × (1 + output growth) × (1 – productivity growth) – 1. Numbers may not add up to totals due to rounding.

We discuss our forecasts for price, output and productivity growth below, including the reasons for any differences between our forecast and AGN's.

32 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, October 2024, pp. 22–23.

3.5.2.1 Forecast price growth

AGN proposed average annual price growth of 0.8%,[33] which increased its total opex forecast by $7.2 million. We have used lower annual price growth rates, which averaged 0.6%. The price growth rates we used increased our total opex alternative estimate by $5.2 million.

Both we and AGN forecast price growth as a weighted average of forecast labour price growth and non-labour price growth:

- AGN used a weighted average of wage price index (WPI) growth forecasts for the electricity, gas, water and waste services (utilities) industry and the construction industry in South Australia to forecast labour price growth. AGN sourced both forecasts from its consultant, Oxford Economics.[34] In our alternative estimate, we averaged the utilities industry forecast from Oxford Economics with more recent forecasts from our consultant, Deloitte Access Economics.[35]
- both we and AGN applied a forecast non-labour real price growth rate of zero.[36]
- we applied different weights to account for the proportion of opex that is labour and non-labour than AGN. AGN used weights of 71% for labour inputs and 29% for non-labour inputs.[37] We used weights of 68% and 32% for labour and non-labour inputs respectively.

Consequently, the key differences between our real price growth forecasts and AGN's is that:

- we have not included WPI growth rates for the construction industry in our labour price growth rate
- we have used an average of 2 forecasts for the South Australian utilities industry to forecast labour price growth
- we have used different input price weights.

We discuss these issues below.

3.5.2.1.1 Forecast labour price growth should reflect the utilities industry

We have used only the WPI growth rates for the utilities industry in our forecast of labour price growth. AGN used a weighted average of WPI growth for the utilities industry (80% weight) and the construction industry (20% weight).[38]

We did not include forecasts for the construction industry in our labour price growth forecasts, because the distribution of natural gas through mains systems is included in the electricity, gas, water and waste services industry, which we call utilities, under the Australian

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33 AGN SA, *2026–2031 Final plan*, 11 July 2025, p. 89.

34 AGN SA, *2026–2031 Final plan*, 11 July 2025, p. 89.

35 Deloitte Access Economics, *Labour price growth forecasts*, 30 July 2025, p. 10.

36 AGN SA, *2026–2031 Final plan*, 11 July 2025, p. 89.

37 AGN SA, *2026–2031 Final plan*, 11 July 2025, p. 89.

38 AGN SA, *Attachment 8.1_Opex forecast model*, July 2025.

and New Zealand standard industrial classification.[39] This is also consistent with the econometric studies we have used to test output and productivity growth.[40]

We have updated our forecasts of WPI to reflect the latest available information. Our standard approach to forecasting labour price growth is to use an average of 2 WPI growth forecasts for the utilities industry in the relevant state. We use one set of forecasts provided by the network, and one set that we receive from our own consultant. For this determination, we engaged Deloitte Access Economics to provide WPI growth forecasts for the South Australian utilities industry.[41]

3.5.2.1.2 Forecasts from multiple sources will likely be more accurate than a single forecast

AGN used only forecasts from its consultant, Oxford Economics. We consider using an average of the forecasts from both Oxford Economics and Deloitte Access Economics is likely to produce the best forecast possible in the circumstances.[42] We have previously tested the accuracy of the forecasts from these 2 consultants and found that, although Deloitte Access Economics was more accurate than Oxford Economics at that time, an average of the 2 was the most accurate.[43]

Since AGN submitted its access arrangement proposal, we have received new WPI growth forecasts from Deloitte Access Economics, which reflect more up-to-date economic information. We used these newer forecasts in addition to Oxford Economics' forecasts for the South Australian utilities industry, which AGN submitted.[44]

3.5.2.1.3 The input price weights should match those used in the econometric studies

AGN used weights of 71% and 29% for labour and non-labour inputs respectively. It stated that these were the AER benchmark weights.[45] However, these are not the input price weights we use for gas distribution. Consistent with past gas distribution determinations, we have used weights of 62% for labour and 38% for non-labour inputs. We use these weights because these are the weights used in the econometric studies.[46] This ensures that our input specification is consistent with the input price specification used to derive forecast output growth and productivity growth.

We show the labour price growth forecasts from Oxford Economics, Deloitte Access Economics and the average WPI growth rate in Table 3.4.

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39 ABS, Australian and New Zealand Standard Industrial Classification, D Electricity, Gas, Water and Waste Services, https://www.abs.gov.au/statistics/classifications/australian-and-new-zealand-standard-industrial-classification-anzsic/2006-revision-2-0/detailed-classification/d

40 See, for example, ACIL Allen, *Opex partial productivity study 2022, Report to Australian Gas Networks (VIC and Albury), Multinet and AusNet*, 16 June 2022, p. 11.

41 Deloitte Access Economics, *Labour price growth forecasts*, 30 July 2025.

42 This is consistent with the requirement under r. 74(2) of the NGR.

43 AER, *Final decision, SA Power Networks Distribution Determination 2020 to 2025, Attachment 6*, June 2020, pp. 14–18.

44 Oxford Economics, *Input cost escalation: Forecasts to 2030/31 prepared by Oxford Economics Australia for Australian Gas Networks (South Australia)*, May 2025.

45 AGN SA, *2026–2031 Final plan*, 11 July 2025, p. 89.

46 See, for example, ACIL Allen, *Opex partial productivity study 2022, Report to Australian Gas Networks (VIC and Albury), Multinet and AusNet*, 16 June 2022, p. 11.

Table 3.3 Forecast labour price growth, %

	2026–27	2027–28	2028–29	2029–30	2030–31
AGN's proposal					
WPI – Utilities – Oxford Economics	0.9	0.9	1.1	1.3	1.3
WPI – Construction – Oxford Economics	0.6	0.8	1.0	1.3	1.0
Weighted average	**0.8**	**0.9**	**1.1**	**1.3**	**1.2**
AER alternative estimate					
WPI – Utilities – Oxford Economics	0.9	0.9	1.1	1.3	1.3
WPI – Utilities – DAE	0.4	0.7	0.7	1.0	1.0
Average	**0.6**	**0.8**	**0.9**	**1.1**	**1.1**
Difference	**–0.2**	**–0.1**	**–0.2**	**–0.2**	**–0.1**

Source: Oxford Economics, *Input cost escalation: Forecasts to 2030/31 prepared by Oxford Economics Australia for Australian Gas Networks (South Australia)*, May 2025, p. 4; Deloitte Access Economics, *Labour price growth forecasts*, 30 July 2025, p. 10.

3.5.2.2 Forecast output growth

AGN proposed average annual output growth of 0.3%,[47] which increased its proposed opex forecast by $2.9 million. We have also forecast average annual output growth of 0.3%. This increases our alternative estimate of total forecast opex by $2.8 million.

3.5.2.2.1 Assessment of output growth

For electricity distribution determinations, we typically forecast output growth based on the forecast growth in a defined output measure, based on econometric modelling. However, for gas distribution decisions, we have not undertaken the modelling needed to determine a standard industry output specification.

To assess AGN's output and productivity growth forecasts, we tested how the proposed output growth, net of productivity growth, compares to the output and productivity growth forecast using the output specifications derived from the available econometric studies. These econometric studies have been submitted in previous gas reset processes and were undertaken between 2015 and 2022.[48] We have taken the opex cost functions estimated by each of these studies and forecast output and productivity growth using the forecast growth in energy throughput, customer numbers and mains length. In this way we have produced output and productivity growth forecasts specific to AGN's circumstances. When we compared the results of the different studies, we compared forecast output growth and

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47 AGN SA, *2026–2031 Final plan*, 11 July 2025, p. 89.

48 ACIL Allen, *Opex partial productivity analysis, Report to Australian Gas Networks Limited*, 20 December 2016; Economic Insights, *Relative opex efficiency and forecast opex productivity growth of Jemena Gas Networks*, February 2015; Economic Insights, *Gas distribution businesses opex cost function, Report prepared for Multinet Gas*, 22 August 2016; Economic Insights, *Relative efficiency and forecast productivity growth of Jemena Gas Networks (NSW)*, 24 April 2019; ACIL Allen, *Opex partial productivity study 2022, Report to Australian Gas Networks (VIC and Albury), Multinet and AusNet*, 16 June 2022.

productivity growth together because an output specification that yields higher output growth tends to also give higher forecast productivity growth.

When we compared AGN's average annual output growth net of productivity growth of –0.1% against the forecasts based on each of the available econometric studies, we found it to be within the reasonable range formed by the studies, as shown in Table 3.5. Consequently, we are satisfied that AGN's forecast of output growth, net of productivity growth, is reasonable in these circumstances.[49]

Table 3.4 Comparison of forecast output growth net of productivity growth

Model specification	Output growth	Productivity growth	Output growth net of productivity growth
Proposed	**0.32%**	**0.40%**	**–0.08%**
ACIL Allen (2016)	0.50%	0.62%	–0.12%
Economic Insights (2015)	–1.00%	0.21%	–1.20%
ACIL Allen (2016)	0.52%	0.64%	–0.12%
Economic Insights (2016)	0.45%	0.30%	0.15%
Economic Insights (2019)	**0.40%**	**0.73%**	**–0.33%**
ACIL Allen (2022)	0.23%	0.23%	0.00%
CEG (2024)	**0.40%**	**0.11%**	**0.29%**
Minimum			**–0.33%**
Maximum			**0.29%**

Source: AGN SA, *2026–2031 Final plan*, 11 July 2025, p. 89; AER analysis.
Note: We have only included the results of those studies that reliably estimated individual parameters (that is, the estimated coefficient is of the expected sign) in forming the reasonable range. Consequently, we have excluded the results from Economic Insights (2015) and Economic Insights (2016), which are highlighted grey.
Numbers may not add up to total due to rounding.

3.5.2.3 Forecast productivity growth

AGN's proposal included forecast average annual productivity growth of 0.4%.[50] We have used the same forecast in our alternative estimate.

The econometric analyses previously submitted by gas distributors found both a negative time trend and positive returns to scale. That is, the studies found that, all else equal, opex reduces over time and that when output increases, opex increases at a lower rate. This suggests that, at least while output is growing, gas distributors should be able to achieve productivity growth. AGN's proposal is consistent with this.

49 NGR, r. 74(2).

50 AGN SA, *2026–2031 Final plan*, 1 July 2025, p. 89.

Because AGN's forecast of output growth net of productivity growth falls within the reasonable range of previous econometric studies (Table 3.5), we have adopted AGN's proposed productivity growth in our alternative estimate.

3.5.3 Step changes

In developing our alternative estimate, we include prudent and efficient step changes for cost drivers such as new regulatory obligations or efficient capex / opex trade-offs. As we explain in the Expenditure Forecast Assessment Guideline for electricity, we will generally include a step change if the efficient base opex and the rate of change in opex of an efficient service provider do not already include the proposed cost for such items, and they are required to meet the opex criteria.[51]

AGN's proposal included 6 step changes totalling $86.5 million (18.6% of total forecast opex).[52] These are shown in Table 3.6, along with our alternative estimate for the draft decision, which is to include step changes totalling $36.1 million. The difference is largely because we have not included the following 4 step changes:

1. Purchase of renewable gas guarantee of origin certificates (–$26.0 million)
2. Transition from APA – AGN IT costs (–$18.5 million)
3. Abolishment for safety at redundant sites (–$4.6 million)
4. Cyber security ($1.2 million).

Table 3.5 Step changes ($million, 2025–26)

Step change	AGN's proposal	AER draft decision	Difference
Change in capitalisation policy – Overheads	32.0	32.0	–
Purchase of Renewable Gas of Origin Certificates	26.0	–	–26.0
Transition from APA – AGN IT costs	18.5	–	–18.5
Abolishment of redundant sites	4.6	–	–4.6
Application upgrades and enhancements	4.1	4.1	–
Cybersecurity	1.2	–	–1.2
Total	**86.5**	**36.1**	**–50.3**

Source: AGN SA, *Attachment 8.1_Opex Forecast Model*, 1 July 2025; AER analysis.
Note: Amounts of '0.0' and '–0.0' represent small non-zero values and '–' represents zero.

[51] AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, October 2024, p. 26.

[52] AGN SA, *Attachment 8.1_Opex Forecast Model*, 1 July 2025.

3.5.3.1 Change in capitalisation policy – Overheads

We have included in our alternative estimate AGN's proposed step change of $32.0 million for the change in its capitalisation policy towards overheads. We consider this to be an efficient allocation of its expenditure, which aligns with our final decision for AGN's (Victoria and Albury) 2023–28 access arrangement.

Table 3.6 Change in capitalisation policy – Overheads ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
AGN's proposal	6.4	6.4	6.4	6.5	6.3	32.0
AER draft decision	6.4	6.4	6.4	6.5	6.3	32.0
Difference	–	–	–	–	–	–

Source: AGN SA, *Attachment 8.1_Opex Forecast Model*, 1 July 2025; AER analysis.
Note: Numbers may not add up to total due to rounding. Amounts of '0.0' and '–0.0' represent small non-zero values and '–' represents zero.

AGN proposed a total of $32.0 million for the reclassification of a portion of its corporate overheads from capex to opex to align with its new capitalisation policy. It proposed allocating to opex 59% of costs related to:[53]

- the operation and maintenance of capital projects
- the procurement of vehicles
- indirect costs to support the provision of the above, such as for human resources.

AGN submitted that this was a capex to opex trade off and not an increase in its overall expenditure. It also submitted that this approach aligns with the AER's final decision for AGN's (Victoria and Albury) 2023–28 access arrangement, and that this is an efficient trade off to reduce the growth in its asset base.

We have reviewed and confirmed that these costs have been deducted from AGN's capex forecast and reallocated to opex. The capitalisation change has not resulted in an increase to AGN's total expenditure. We note that there is a minor discrepancy in the 2 estimates between AGN's capex and opex forecasts, which AGN will amend in its revised proposal. We are also satisfied that this step change aligns with a similar step change in AGN's (Victoria and Albury) 2023–28 access arrangement final decision, where we found these costs to meet the characteristics of opex, and that this capex to opex reallocation was reasonable and efficient.[54]

Consistent with our 2023–28 final decision for AGN (Victorian and Albury), we consider it is prudent and efficient for AGN to allocate these costs to opex. We have therefore included this step change in our alternative estimate for the draft decision.

[53] AGN SA, *2026–2031 Final plan*, 11 July 2025, pp. 86–87.

[54] AER, *AGN 2023–28 – Draft Decision - Attachment 6 – Operating expenditure*, December 2022, pp. 29–30.

3.5.3.2 Purchase of renewable gas guarantee of origin certificates

We have not included the 'Purchase of renewable gas guarantee of origin certificates' step change in our alternative estimate of total forecast opex. We are not satisfied that this represents prudent and efficient expenditure, including that this is not required to deliver pipeline services.

Table 3.7 Purchase of renewable gas guarantee of origin certificates step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2300–31	Total
AGN's proposal	–	–	8.7	8.7	8.7	26.0
AER draft decision	–	–	–	–	–	–
Difference	**–**	**–**	**–8.7**	**–8.7**	**–8.7**	**–26.0**

Source: AGN SA, *Attachment 8.1_Opex Forecast Model*, 1 July 2025; AER analysis.
Note: Numbers may not add up to total due to rounding. Amounts of '0.0' and '–0.0' represent small non-zero values and '–' represents zero.

AGN proposed $26.0 million (5.6% of total forecast opex) to purchase renewable gas guarantee of origin certificates for the proposed HypAdelaide hydrogen production facility.[55] AGN submitted that this proposal may become a future jurisdictional scheme, and that the expenditure is consistent with its priority to deliver a more sustainable energy future, the South Australian Government's emission reduction objectives, and the NGO. It further clarified that it plans to commence purchasing the certificates from 2028–29, which it then intends to on-sell to its industrial customers to offset their emissions. AGN stated this will eventually wholly offset certificate purchase costs.[56]

The submission from the South Australian Reference Group Review Panel stated that it does not support the concept of customers paying for the renewable gas certificates to support the economics of HypAdelaide. It also considered it unlikely there will be a future for hydrogen, particularly from an economic perspective, and observed that limited information is available on the details of the potential state government jurisdictional scheme.[57] CCP33 similarly questioned the economic viability of hydrogen gas and did not support this step change.[58] The SACOSS also considered it inappropriate for AGN to build in assumptions related to government schemes that have not yet been announced. It emphasised that it should not be on consumers to bear the risks and costs of this unproven policy mechanism.[59] Energy Consumers Australia similarly questioned whether hydrogen would become economic and emphasised that consumers should not be required to pay for renewable gas projects that consumers are unlikely to benefit from. It noted that should AGN wish to undertake these

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55 AGN SA, *2026–2031 Final plan*, 11 July 2025, p. 87.

56 AGN SA, *2026–2031 Final plan*, 11 July 2025, p. 87.

57 South Australian Reference Group Review Panel, *Submission on AGN (SA) 2026–31 Access arrangement proposal*, August 2025, pp. 4–6, 19.

58 CCP33, *Advice to AER – Submission on AGN (SA) 2026–31 Access arrangement proposal*, August 2025, pp. 32–33.

59 SACOSS, *Submission on AGN SA 2026–31 Access arrangement proposal*, August 2025, pp. 4–5.

investments, it should bear the risk of those investments, rather than shifting the risk to network consumers.[60]

We assessed the information provided in AGN's initial proposal, including information received through an information request. Overall, we are not satisfied AGN provided sufficient information to demonstrate the prudency and efficiency of the proposed step change, and have identified the following concerns with this proposal:

1. AGN did not provide, in either its initial proposal or through its response to our request for further information, information that demonstrated that the proposed expenditure is required for delivering pipeline services.
2. 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.
3. The proposal appears to allocate the full cost of purchasing certificates to consumers, without accounting for expected offsetting revenue streams. That is, consumers pay higher network tariffs from this expenditure, while AGN projects to receive 2 separate revenue streams: revenue through network tariffs for the purchase of certificates; and a secondary revenue stream through on-selling the certificates to industrial customers.
4. We do not consider it prudent to include forecast opex for potential regulatory obligations that do not have defined details and timelines. We are not satisfied, based on the limited information provided, that AGN has provided sufficient information to support the need for this expenditure in the circumstances.

For the reasons set out above, we have not included the 'Purchase of renewable gas guarantee of origin certificates' step change in our alternative estimate of total forecast opex.

3.5.3.3 Non-recurrent IT transition costs (APA to AGN)

We have not included the $18.6 million step change for the transition of IT from APA to AGN in our alternative estimate of total forecast opex for the draft decision. This reflects that we are not satisfied that the proposed step change is prudent and efficient.

Table 3.8 Non-recurrent IT transition costs step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
AGN's proposal	–	6.3	8.9	3.5	–0.1	18.6
AER draft decision	–	–	–	–	–	–
Difference	**–**	**–6.3**	**–8.9**	**–3.5**	**0.1**	**–18.6**

Source: AGN SA, *Attachment 8.1_Opex Forecast Model*, 1 July 2025; AER analysis.
Note: Amounts of '0.0' and '–0.0' represent small non-zero values and '–' represents zero.

60 Energy Consumers Australia, *Submission on AGN SA and Evoenergy 2026–31 Access arrangement proposal*, August 2025, pp. 3–4.

AGN proposed $18.6 million (4.0% of total forecast opex) for the insourcing of IT services currently provided under contract with APA, which will expire in 2027. We note the proposal also includes corresponding capex (refer Attachment 2). The opex proposal is for software applications, infrastructure, security and connectivity arrangements.[61] The amounts are additional to the base opex expenditure currently paid for services to APA.

AGN submitted that APA has divested this aspect of its business.[62] Our assessment subsequently identified that Australian Gas Infrastructure Group (AGIG) acquired this new business aspect. AGIG consists of the Australian Gas Networks, the Dampier Bunbury Pipeline and Multinet Gas Network. Currently, AGIG has contracts with APA Group for the provision of asset management, field services, finance, HR and IT support.[63] In response to questions during a workshop, AGN advised that AGIG is principally a trading name, with all 3 networks operating separately, and only sharing some services (e.g. IT). AGN's proposal further noted that the ICT infrastructure (capex and opex) is owned and operated by AGIG, with AGN utilising these facilities to operate its gas network.

Based on the information available, we are not satisfied AGN has sufficiently demonstrated the prudency of this step change. Our assessment identified uncertainty regarding the relationship between AGN and AGIG, which we have not yet resolved, and which goes to the question of whether proposed costs are appropriately allocated to AGN as the regulated entity. AGN throughout its proposal stated that this expenditure is for AGIG, including to develop and uplift AGIG's capabilities.[64] We note that AGIG is a registered business with its own ABN, that is not a regulated network business. This decision relates to forecast opex (and capex) for AGN's access arrangement for the 2026–31 period. AGN's transition costs from APA to AGIG should therefore only include costs required for AGIG to provide ongoing services to AGN, similar to its current APA arrangement, rather than for AGIG's establishment infrastructure or similar costs. Further, if the proposed expenditure was to be incurred by a prudent service provider acting efficiently,[65] we expect that these costs would be similar to those currently incurred through AGN's contract with APA.

In terms of the cost estimates, we are further not satisfied AGN provided sufficient information to support the proposed costs. For instance, AGN has not provided supporting cost-benefit analysis, and only limited details on the proposed scope of work. We further consider insufficient information is available to justify the input rates, including labour rates and hours, which appear high in this context. We provide further information on our assessment in Attachment 2 of this draft decision.

For our alternative estimate for the draft decision, we have therefore not included the proposed IT transition costs. We are not satisfied that AGN has provided adequate information to demonstrate that the proposed expenditure is for AGN, as the regulated entity, to continue to efficiently procure relevant services, rather than directly funding capacity and

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61 AGN SA, *2026–2031 Final Plan*, 11 July 2025, p. 87.

62 APA, *APA executes agreement to divest gas distribution operations and maintenance entities*, 19 August 2025.

63 AGN SA, *Attachment 9.9_Business Cases (IT projects)*, 1 July 2025, p.145.

64 AGN SA, Attachment 9.7_IT Investment Plan, 1 July 2025, pp. 22–23; AGN SA, *Attachment 9.9_Business Cases (IT projects)*, 1 July 2025, pp.143–160.

65 NGR, r. 91(1).

upgrades for AGIG. In AGN's revised proposal, we seek additional information from AGN to address our concerns, including providing a written disclosure of the company structure, and a clearly specified attribution of the transition project costs.

3.5.3.4 Abolishment of redundant sites

We have not included a step change for the abolishment of redundant sites in our alternative estimate of total forecast opex.

Table 3.9 Abolishment of redundant sites step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
AGN's proposal	0.9	0.9	0.9	0.9	0.9	4.6
AER draft decision	–	–	–	–	–	–
Difference	**–0.9**	**–0.9**	**–0.9**	**–0.9**	**–0.9**	**–4.6**

Source: AGN SA, *Attachment 8.1_Opex Forecast Model*, 1 July 2025; AER analysis.
Note: Numbers may not add up to total due to rounding. Amounts of '0.0' and '–0.0' represent small non-zero values and '–' represents zero.

AGN proposed $4.6 million (1.0% of total forecast opex) to permanently remove service lines from 3,500 redundant 'inlet only' services. These residential services have a live supply to the metering location, including a vertical standpipe, but no meter in place. AGN considers sites that have not had gas meters for over 24 months to be redundant. AGN stated that some of these customers may not be aware they have live gas assets on their property. As such, it considers leaving a redundant service live carries a risk of damage and potential leak and ignition.

AGN proposed removing these redundant services over a 5-year period.

We have several concerns with this proposed step change and consider that AGN has not provided sufficient information or analysis to demonstrate these costs are required to address a safety issue. Our concerns include that:

- there is no regulatory obligation to remove redundant services
- AGN did not provide evidence of any incidents involving redundant services
- AGN did not provide evidence of an increased risk if redundant services are not abolished
- 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
- AGN did not provide a basis for the proposed 24-month period for a service to be deemed redundant
- it is likely that some customers with a dormant connection would value that connection, and consequently, not every connection would need to be removed.

Further, AGN did not provide evidence that it sought, or received, advice from the Office of the Technical Regulator, the relevant safety regulator, on the need for this program.

Without the above evidence, we cannot be satisfied that the proposed expenditure would be incurred by a prudent service provider acting efficiently.[66] We are also not satisfied that the forecast was arrived at on a reasonable basis and represents the best forecast possible in the circumstances.[67]

3.5.3.5 Cyber security (data privacy/security and access control)

We have not included the proposed $1.2 million cyber security step change in our alternative estimate of total forecast opex for the draft decision. This reflects that we are not satisfied that these costs represent prudent and efficient expenditure, including that the proposed step change amount is likely to be accounted for in AGN's base opex and the rate of change under our opex forecasting approach.

Table 3.10 Cyber security step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
AGN's proposal	0.0	0.3	0.3	0.3	0.3	1.2
AER draft decision	–	–	–	–	–	–
Difference	**–0.0**	**–0.3**	**–0.3**	**–0.3**	**–0.3**	**–1.2**

Source: AGN SA, *Attachment 8.1_Opex Forecast Model*, 1 July 2025; AER analysis.
Note: Amounts of '0.0' and '–0.0' represent small non-zero values and '–' represents zero.

AGN proposed $1.2 million (0.3% of total forecast opex) to meet obligations arising from the Security of Critical Infrastructure and privacy legislation, and Foreign Investment Review Board conditions. AGN submitted these costs are required to achieve an uplift in its capabilities, to adequately address growing cyber security risks. AGN also submitted that its proposed program is based on a risk-based approach.[68] We note AGN has a corresponding capex cyber security proposal. Further details of this program can be found in Attachment 2 – Capital expenditure of this draft decision. The discussion below focuses on the proposed opex step change component of these costs.

We assessed AGN's proposed step change, including through the information provided in the respective business case and model, the responses received to our information requests, and information obtained through a workshop.

We are satisfied that AGN has prudently developed its cyber security maturity, including through a risk-based approach. We further consider it prudent for AGN to continue to invest and maintain its cyber security maturity in a growing threat environment, including to develop its capabilities to meet all new regulatory obligations.

However, we consider that the proposed step change risks double counting costs already provided through our base-step-trend forecasting approach. That is, this relatively small step up in costs for an existing category of expenditure will be accounted for through the base and trend components of our opex forecasting approach. We note that forecast opex is

66 NGR, r. 91(1).

67 NGR, r. 74(2).

68 AGN SA, *2026–31 Final Plan*, 11 July 2025, p. 88.

established on a top-down basis, and thus any rate of change uplift is inherently also based on a top-down rather than a bottom-up category level activity. This means that this trend uplift is not solely for base activities, but for continued growth and adaptation of the business over time. As noted in the Expenditure Forecast Assessment Guideline and the Better Resets Handbook,[69] step changes should not double count costs provided through other components of forecast opex, such as base opex and rate of change. We also note the concerns raised in Attachment 2 on this expenditure category. These concerns similarly apply to opex, and raise further concerns regarding the prudency of this proposal.

For the reasons set out above, we have not included the cyber security step change in our alternative estimate of total forecast opex.

3.5.3.6 Other IT applications and upgrades

We have included AGN's proposed $4.1 million for the Other IT applications upgrades and enhancements step change in our alternative estimate. Consistent with our capex position, we consider these costs to be prudent and efficient.

Table 3.11 Other applications and upgrades step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
AGN's proposal	0.7	0.8	0.9	0.9	0.8	4.1
AER draft decision	0.7	0.8	0.9	0.9	0.8	4.1
Difference	–	–	–	–	–	–

Source: AGN SA, *Attachment 8.1_Opex Forecast Model*, 1 July 2025; AER analysis.
Note: Amounts of '0.0' and '–0.0' represent small non-zero values and '–' represents zero.

AGN proposed a total of $4.1 million (0.9% of total forecast opex) for necessary upgrades to several of its corporate and operational IT applications to newer versions,[70] to ensure that they are fit for purpose and can adequately manage technology risks and prevent material outages. In addition to increasing data and storage costs to integrate digital metering data into their billing system.

Consistent with our capex position for these projects, we do not have any material concerns with these costs and consider them likely to be prudent and efficient. We have therefore included them in our alternative estimate of total forecast opex.

3.5.4 Category specific forecasts

AGN's proposal included 2 category specific forecasts, which were not forecast using the base-step-trend approach. These were for debt raising costs and UAFG costs.

69 AER, *Final decision, Expenditure forecast assessment guideline – electricity distribution*, October 2024, pp. 24–25

70 AGN SA, *Attachment 9.7_IT Investment Plan*, July 2025, pp. 17–21.

3.5.4.1 Debt raising costs

We have included debt raising costs of $5.5 million in our alternative estimate. This is $0.3 million higher than the $5.1 million proposed by AGN.[71]

Table 3.12: Debt raising costs ($million, 2025–26)

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
AGN's proposal	1.0	1.0	1.0	1.0	1.1	5.1
AER alternative estimate	1.1	1.1	1.1	1.1	1.1	5.5
Difference	**–**	**0.1**	**0.1**	**0.1**	**0.1**	**0.3**

Source: AGN SA, *2025–30 Access arrangement proposal - Attachment 8.1_Opex Forecast Model,* July 2025; AER analysis.
Note: Numbers may not add up to total due to rounding. Amounts of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

Debt raising costs are transaction costs incurred each time a business raises or refinances debt. Our preferred approach is to forecast debt raising costs using a benchmarking approach rather than a service provider's actual costs in a single year. This provides consistency with the forecast of the cost of debt in the rate of return building block. This is the basis for our alternative estimate in Table 3.13. We used our standard approach to forecast debt raising costs.

3.5.4.2 Unaccounted for gas costs

We have included forecast UAFG costs of $14.6 million in our alternative estimate. This is $13.2 million lower than AGN's proposal because we are not satisfied that AGN's forecast price and volume of UAFG reasonably reflect the forecasts and estimates criteria.[72] We have applied alternative UAFG price and volume as set out below.

AGN proposed a category specific forecast of $27.9 million for UAFG and a true-up factor in its tariff variation mechanism for the cost of gas assumed in the forecast.[73] AGN stated that it maintained a consistent approach to forecast UAFG to the one it applied over the 2021–26 period. It forecast its UAFG costs for the 2026–31 period by multiplying:[74]

- the annual average volume of UAFG in the last 3 years of settled UAFG volumes, being 2020–21, 2021–22, and 2022–23.

by:

- the forecast average price of gas, which it 'based on current market indications for securing firm gas' to meet its UAFG quantity requirements.

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71 AGN SA, *Attachment 8.1_Opex Forecast Model,* 1 July 2025.

72 NGR, r. 74.

73 AGN SA, *2026–2031 Final plan*, 11 July 2025, p. 90.

74 AGN SA, *2026–2031 Final plan*, 11 July 2025, p. 90.

AGN submitted that it expects to pay higher UAFG prices based on the current market price.[75]

While we are satisfied that including the UAFG category specific forecast in our alternative estimate would result in a total forecast opex that meets the opex criteria, we are not satisfied that AGN's proposed UAFG amount of $27.9 million would result in a total forecast opex that meets the requirements for forecasts and estimates.[76]

We note that the price AGN relied on to forecast its proposed UAFG was set for another network, not the South Australian gas network. Further, this price is significantly higher than the wholesale gas price projections prepared by ACIL Allen for AEMO's 2025 Gas Statement of Opportunities.

We agree with AGN that the downward trend observed from settled volumes of UAFG over the past 6 years reflects its mains replacement program. However, we consider that UAFG volumes are likely to continue to decrease beyond the 3-year period on which AGN based its forecast volume of UAFG. This is because AGN is projected to carry out further mains replacement work over the 2026–31 period. In contrast, AGN stated that UAFG volumes will stabilise.

Based on the above reasons, we have relied on ACIL Allen's wholesale gas price projections and a 3-year average UAFG volume including the 2023–24 year for which UAFG volumes will settle after our draft decision. We consider that an unsettled 2023–24 volume will be more reflective of AGN's UAFG volumes going forward than a settled 2020–21 volume. We request that AGN update the 2023–24 UAFG volume when it becomes settled.

We compare both forecasts in Table 3.14.

Table 3.13: Unaccounted for gas costs ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
AGN's proposal	5.6	5.6	5.6	5.6	5.6	27.9
AER alternative estimate	3.1	3.0	3.0	2.8	2.7	14.6
Difference	**–2.5**	**–2.6**	**–2.6**	**–2.7**	**–2.8**	**–13.2**

Source: AGN SA, *Attachment 8.1_Opex Forecast Model,* 1 July 2025; AER analysis.
Note: Numbers may not add up to total due to rounding. Amounts of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

3.6 Revisions

We require the following revisions to make the access arrangement proposal acceptable as set out in Table 3.11.

75 AGN SA, *2026–2031 Final plan*, 11 July 2025, p. 79.

76 NGR, r. 74.

Table 3.14 Opex revisions

Revision	Amendments
Revision 3.1	Make all necessary amendments to reflect our draft decision on the proposed opex forecast for the 2026–31 access arrangement period, as set out in section 3.1.

Glossary

Term	Definition
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGIG	Australian Gas Infrastructure Group
AGN	Australian Gas Networks (South Australia)
capex	capital expenditure
CCP33	Consumer Challenge Panel, sub-panel 33
ECM	Efficiency carryover mechanism
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
opex	Operating expenditure
RBA	Reserve Bank of Australia
SACOSS	South Australian Council of Social Services
UAFG	Unaccounted for gas
WPI	Wage price index