DRAFT DECISION
Australian Gas Networks (SA) Access Arrangement

2021 to 2026

Attachment 6
Operating expenditure

November 2020

AUSTRALIAN
ENERGY
REGULATOR

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Note

This attachment forms part of the AER's draft decision on the access arrangement that will apply to Australian Gas Networks (SA) ('AGN') for the 2021–2026 access arrangement period. It should be read with all other parts of the draft decision.

The draft decision includes the following documents:

Overview

Attachment 1 – Services covered by the access arrangement

Attachment 2 – Capital base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency carryover mechanism

Attachment 9 – Reference tariff setting

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Attachment 11 – Non-tariff components

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Contents

6 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.

This attachment outlines our assessment of AGN's proposed opex forecast for the 2021–26 access arrangement period.

6.1 Draft decision

Our draft decision is to include our alternative estimate of total opex forecast of $333.8 million ($2020–21), including debt raising costs, for the 2021–26 access arrangement period. We are not satisfied AGN's forecast opex meets the opex criteria[1] and the requirements for forecasts and estimates.[2]

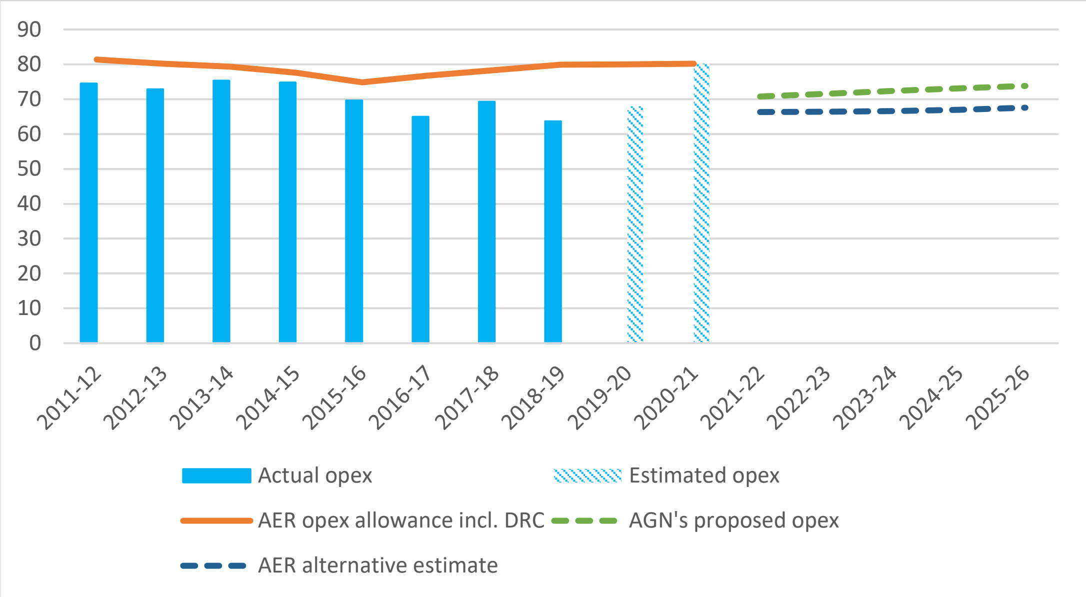
Our alternative estimate of total opex for the 2021–26 period is $27.9 million ($2020–21), or 7.7 per cent, lower than AGN's proposed opex forecast of $361.8 million ($2020–21), including debt raising costs. We set out AGN's proposed opex forecast and our draft decision alternative estimate of total opex in Table 6.1.

Figure 6.1 compares the opex forecast we approve in this draft decision to AGN's proposal, the forecasts we approved for 2011–21 and AGN's actual opex in that period. Our opex draft decision is lower than AGN's opex allowance for 2016–21. This was driven by opex efficiency improvements in the 2016–21 period, reflected in AGN's opex base for 2021–26 and reductions in UAFG costs relative to the 2016–21 period.

[1] NGR, r. 74.

[2] NGR, r. 91.

Figure 6.1 AER's draft decision compared to AGN's past and proposed opex ($million, 2020–21)



Source: AGN, *Final Plan*: *Five year plan for our South Australian network, 2021–2026 -Supporting document – Annual reset RIN*, 30 September 2020; AER, *AER Final Decision – Australian Gas Networks Arrangement – Post Tax Revenue Model*, May 2016; AER, *Envestra SA – PTRM – final decision – amended – tribunal varied,* January 2012; AER analysis.

Note: Includes debt raising costs and unaccounted for gas.

Table 6.1 sets out AGN's proposal and our draft decision alternative estimate.

Table 6.1 AER's alternative estimate compared to AGN's opex proposal for the 2021–26 access arrangement period ($million, 2020–21)

	AGN's proposal	AER's alternative estimate	Difference
Based on reported opex in 2019–20	338.5	339.5	0.9
Base year adjustments	–48.6	–52.1	–3.5
2019–20 to 2020–21 increment	4.0	1.1	–2.9
Output growth	7.3	6.9	–0.4
Price growth	4.4	–1.4	–5.8
Productivity growth	–3.7	–3.4	0.2
Step changes	8.1	0	–8.1
Category specific forecasts	47.2	38.9	–8.3
Total opex (excluding debt raising costs)	**357.4**	**329.4**	**–27.9**
Debt raising costs	4.4	4.4	0.0
Total opex (including debt raising costs)	361.8	333.8	**–27.9**

Source: AER analysis; AGN, *Final Plan*: *Five year plan for our South Australian network, 2021–2026 – Supporting document – Proposal Opex model,* July 2020.

Note: Numbers may not add up to total due to rounding.

The key differences between AGN's opex proposal and our draft decision alternative estimate are:

- we have used a more recent inflation forecast from the Reserve Bank of Australia (RBA).[3]
- we have forecast a lower input price growth rate compared to that proposed by AGN. We have forecast labour price growth using only Deloitte Access Economics' (Deloitte) forecasts.[4] This is a change to our previous approach of averaging the forecasts from Deloitte and the business' consultant (generally BIS Oxford Economics). It reflects that the price growth estimates submitted by AGN are not reflective of the economic and financial impacts resulting from COVID-19. For the final decision we will consider updating the rate of change forecast using our standard approach provided the necessary forecasts are available.
- we have not included the three step changes proposed by AGN. Two of the step changes, the digital experience (customer relationship management system) and vulnerable customer assistance program, arose out of the consumer engagement undertaken by AGN. While there was strong consumer support for AGN to undertake both projects, we do not consider that they have been justified as step changes. The customer relationship management system is a refinement of existing services provided by AGN and is compensated for through the forecast rate of change.

  For the vulnerable customer assistance program we require further information that the program will materially increase the quantity or quality of services provided by AGN.

  The other proposed step change is in relation to insurance. We have not included this step change as we consider the impact of these cost increases on AGN's total opex are captured through the rate of change.
- We have adjusted the forecast of unaccounted for gas (UAFG) proposed by AGN due to changes made to the forecast of UAFG volumes and the cost of replacement gas. Our forecast of UAFG volumes accounts for the downward trend in UAFG as a result of AGN's mains replacement program. Our forecast of replacement gas does not factor in the purchase of a portion of gas from renewable sources, as proposed by AGN. We recognise that AGN's customer engagement demonstrated consumer support the initiative. However, we consider it is already open to AGN to purchase replacement gas from renewable sources in accordance with its customers' preferences and be compensated for any additional costs under the tariff variation mechanism.

3 RBA, *Statement on Monetary Policy—Appendix: Forecast*, August 2020.

4 Deloitte Access Economics, *Labour Price Growth Forecasts Prepared for the AER*, August 2020.

6.2 AGN's proposal

AGN used a 'base–step–trend' approach to forecast opex for the 2021–26 period, consistent with our preferred approach.

In applying our base-step-trend approach to forecast opex, AGN:

- used reported opex in 2019–20 as the base for forecasting its opex over the 2021-26 period. AGN did not remove the debt raising costs and movement in provisions in its opex proposal and acknowledged this in correspondence with the AER [5]
- then adjusted its base opex by:
    - removing category specific forecasts for unaccounted for gas
    - applying the approach in the *Expenditure forecast assessment guideline* (the Guideline) to calculate the 2019–20 to 2020–21 opex increment (to arrive at the starting point for its forecast).[6] This increased its opex forecast by $4.0 million ($2020–21).
- applied its overall rate of change forecast to its adjusted base opex, increasing it by $8.0 million ($2020–21). AGN forecast output growth of $7.3 million ($2020–21), input price growth of $4.4 million ($2020–21) and productivity growth reduced forecast opex by $3.7 million ($2020–-21)
- proposed three step changes for a vulnerable customer assistance program, digital customer experience and for insurance premiums. This increased its opex forecast by $8.1 million ($2020–21)
- proposed one opex category specific forecast totalling $47.2 million ($2020–21) for unaccounted for gas
- proposed debt raising costs of $4.4 million ($2020–21).

This resulted in AGN proposing a total opex forecast of $361.8 million ($2020–21) for the 2021–26 period (see Table 6.2), which is 8.0 percent higher than AGN's actual and estimated opex for the 2016–21 period.

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[5] AGN, *Response to Information Request 015 –Base Year Opex*, 3 September 2020.

[6] This increment is necessary to ensure we measure incremental efficiency gains accurately. This is discussed in: AER, *Better Regulation, Explanatory Statement, Expenditure forecast assessment guideline*, November 2013, pp. 62–65.

Table 6.2 AGN's proposed opex for the 2021–26 access arrangement period ($million, 2020–21)

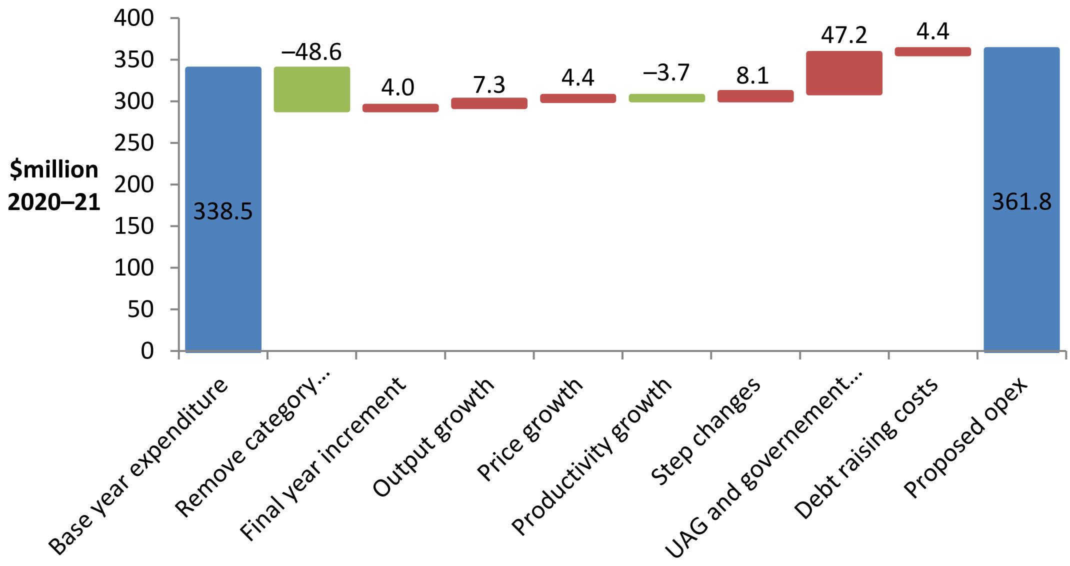
	2020–21	2021– 22	2022–23	2023–24	2024–25	Total
Total opex, excluding debt raising costs	69.9	70.7	71.5	72.3	72.9	**357.4**
Debt raising costs	0.9	0.9	0.9	0.9	0.9	**4.4**
Total opex, including debt raising costs	**70.8**	**71.6**	**72.4**	**73.2**	**73.8**	**361.8**

Source: AGN, *AGN Attachment 7.1 Opex Forecast Model (Public)*, July 2020; AER analysis.

Note: Numbers may not add up due to rounding. Includes debt raising costs.

Figure 6.2 shows the different elements that make up AGN's opex forecast for the 2021–26 period.

Figure 6.2 AGN's opex forecast for the 2021–26 access arrangement period ($million, 2020–21)



Source: AER analysis; AGN, *Final Plan*: *Five year plan for our South Australian network, 2021–2026 – Supporting document – Proposal Opex model*, July 2020.

6.2.1 Stakeholder views

We received submissions from ten stakeholders on AGN's 2021–26 proposal, a number of which raised issues on opex. Submissions broadly supported AGN's opex proposal with particular emphasis on the high level of customer engagement that AGN conducted through their consultants, KPMG.

We have taken these submissions into account in developing the positions set out in this draft decision. Table 6.3 summarises the stakeholder issues raised in submissions.

Table 6.3 Submissions on AGN's 2021–26 opex proposal

Stakeholder	Issue	Description
Consumer Challenge Panel (CCP24) Energy Consumers Australia (ECA)	Base opex	CCP24 stated that the AER should assess the efficiency of the base year expenditure. They also commented that in contrast to the situation with electricity networks, the AER has relatively less data at its disposal to assess gas network efficiency. [7] ECA have supported the used of 2019–20 opex as the base year given that it's the year with the lowest level of opex in the current five year plan. [8]
CCP24,Origin, ECA,	Rate of change	CCP24 stated that price growth forecasts do not reflect the full economic impacts of COVID-19. They expect all forecasts to be revised prior to the AER's final decision.[9] Origin commented that in regards to labour costs it was unclear that the BIS Oxford forecasts incorporate the impact of COVID-19.[10] ECA have stated that the rate of change is consistent with regulatory precedent.[11]
CCP24, South Australian Council Of Social Service (SACOSS), ECA, Business SA, SA Minister for Energy & Mining	Step change	**Vulnerable Customer Assistance Program** CCP24 have raised concerns that the final plan does not provide full detail of the intended vulnerable customer strategy. They also recommended that shareholders should make a contribution to the cost of this program too.[12] The Minister for Energy and Mining was concerned the program will be duplicated by similar programs.[13] SACOSS are supportive but considers it can be funded from existing opex.[14] ECA questioned whether the four initiatives to assist vulnerable customers reduce the financial barriers to greater gas efficiency; and safe and reliable appliances being the most effective initiatives. [15] ECA requested the AER to make further enquiries in relation to the proposal to include expenditure for the vulnerable customer assistance program initiatives. They also raised whether: • The current initiatives that AGN undertakes are adequate. • Is there a double up between initiatives being undertaken by other organisations (such as retailers and charities) and those proposed by AGN.

7 CCP24, *Advice to Australian Energy Regulator on Australian Gas Networks Final Plan for AGN Gas Networks (South Australia) Access Arrangement July 2021-June 2026,* 10 August 2020, p. 24.

8 ECA, *Submission on AGN 2021-26 AA Proposal*, August 2020, p. 14.

9 CCP24, *Advice to Australian Energy Regulator on Australian Gas Networks Final Plan for AGN Gas Networks (South Australia) Access Arrangement July 2021-June 2026,* 10 August 2020.p. 28.

10 Origin, *Submission on AGN 2021-26 AA Proposal,* August 2020, p. 20.

11 ECA, *Submission on AGN 2021-26 AA Proposal*, August 2020, p. 15.

12 CCP24, *Advice to Australian Energy Regulator on Australian Gas Networks Final Plan for AGN Gas Networks (South Australia) Access Arrangement July 2021-June 2026,* 10 August 2020.p. 26.

13 SA Minister Energy and Mining, *Submission on AGN 2021-26 AA Proposal,* August 2020, p. 3.

14 SACOSS, *Submission on AGN 2021-26 AA Proposal,* August 2020, p. 5.

15 ECA, *Submission on AGN 2021-26 AA Proposal*, August 2020, p. 15.

		Digital Customer Experience CCP24 stated that this proposal was supported by customer engagement and is consistent with AGN's proven record in actively seeking to improve interaction with customers. [16] ECA have questioned as to whether the customer relationship management component of this change overlaps with aspects of the vulnerable customer assistance program proposal. [17] **Insurance Premiums** CCP24 advised that the AER should review and assess whether the additional costs over trend are justifiable. [18] SACOSS raised the issue that Evoenergy has not elected to pass on insurance premium increase.[19]
CCP24, Energy Australia, SA Minister for Energy & Mining	Opex category specific forecasts	**UAFG** CCP24 suggest that the AER consider ways that might lead to the networks having a greater incentive to improve on volumes and prices for UAFG given the significant and rising cost put forward in their Final Plan. [20] The SA Minister for Energy & Mining considers this is over estimated and strongly encourages AER to consult with the Office of the Technical Regulator to assess UAFG volumes.[21] Energy Australia noted customer support for using renewables may need to be reinvestigated in wake of COVID-19.[22]
Energy and Water Ombudsman SA, SA Minister for Energy & Mining, South Australia Federation Residents and Ratepayers Associations Inc. (SAFRRA), Business SA, South Australian Financial Counsellors Association (SAFCA)	Consumer Engagement	The Energy and Water Ombudsman SA supports AGN's consumer engagement.[23] The Minister for Energy and Mining South Australia acknowledges AGN's significant consumer consultation.[24] SAFFRA gave accolades for AGN's consumer engagement process.[25] Business SA stated the consumer engagement was genuine, comprehensive and led from the CEO down.[26] SAFCA congratulated AGN on its high level of customer satisfaction and in depth approach to seeking customer input.[27]

16 CCP24, *Advice to Australian Energy Regulator on Australian Gas Networks Final Plan for AGN Gas Networks (South Australia) Access Arrangement July 2021-June 2026,* 10 August 2020.p. 27.

17 ECA, *Submission on AGN 2021-26 AA Proposal*, August 2020, pp.16–17.

18 CCP24, *Advice to Australian Energy Regulator on Australian Gas Networks Final Plan for AGN Gas Networks (South Australia) Access Arrangement July 2021-June 2026,* 10 August 2020.pp. 27–28.

19 SACOSS, *Submission on AGN 2021-26 AA Proposal,* August 2020, p. 3.

20 CCP24, *Advice to Australian Energy Regulator on Australian Gas Networks Final Plan for AGN Gas Networks (South Australia) Access Arrangement July 2021-June 2026,* 10 August 2020.p. 28.

21 SA Minister Energy and Mining, *Submission on AGN 2021-26 AA Proposal,* August 2020, pp. 3–5.

22 Energy Australia, *Submission on AGN 2021-26 AA Proposal,* August 2020, p. 2.

23 Energy and Water Ombudsman SA, *Submission on AGN 2021-26 AA Proposal,* August 2020, p. 2.

24 SA Minister Energy and Mining, *Submission on AGN 2021-26 AA Proposal,* August 2020, p. 1.

25 SAFRRA, *Submission on AGN 2021-26 AA Proposal,* August 2020, p. 4.

26 Business SA, *Submission on AGN 2021-26 AA Proposal,* August 2020, p. 1.

27 SAFCA, *Submission on AGN 2021-26 AA Proposal,* August 2020, p. 3.

6.3 Assessment approach

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

> Operating expenditure must be 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.[28]

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

> A forecast or estimate (a) must be arrived at on a reasonable basis; and (b) must represent the best forecast or estimate possible in the circumstances.[29]

We use a form of incentive based regulation to assess the business' 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.[30]

Once we have developed our alternative estimate of total opex, we compare it with the business' total opex forecast to form a view on the reasonableness of the business' proposal. If we are satisfied the business' total forecast meets the NGR requirements, we accept the forecast. If we are not satisfied, we substitute the business' 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' 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).[31]

6.3.1 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.[32] 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 an opex

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28 NGR, r. 91.

29 NGR, r. 74(2).

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

31 NGL, s. 28(1).

32 Productivity Commission, *Electricity Network Regulatory Frameworks, volume 1, No. 62*, April 2013, p. 188.

allowance is granted over a multi-year regulatory period) and the efficiency carryover mechanism (ECM).[33]

The incentive-based regulatory framework partially overcomes the information asymmetries between the regulated businesses and us.[34] 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 (the NGO).

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 forecasts over time. Revealed opex reflects the efficiency gains made by a business over time. As a network business becomes more efficient, this translates to lower forecasts of opex in future regulatory periods, which means consumers also receive the benefits of the efficiency gains made by the business. Incentive regulation therefore aligns the business' 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 five 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.[35]

Incentive regulation is designed to leave the day-to-day decisions to the network businesses.[36] It allows the network businesses the flexibility to manage their assets and labour as they see fit to comply with the opex criteria[37] and achieve the NGO.[38]

Our general approach is to assess whether opex, in aggregate, is sufficient to satisfy the opex criteria over the access arrangement period, rather than to assess individual opex projects or programs. To do so, we develop an alternative estimate of total opex using the 'base–step–trend' forecasting approach (section 6.3.2). This is generally a 'top-down' approach, but there may be circumstances where we need to use 'bottom-

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

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

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

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

37 NGR, r. 91.

38 NGL, s. 28(1).

up' analysis, particularly in relation to our base opex assessment and for step changes.[39]

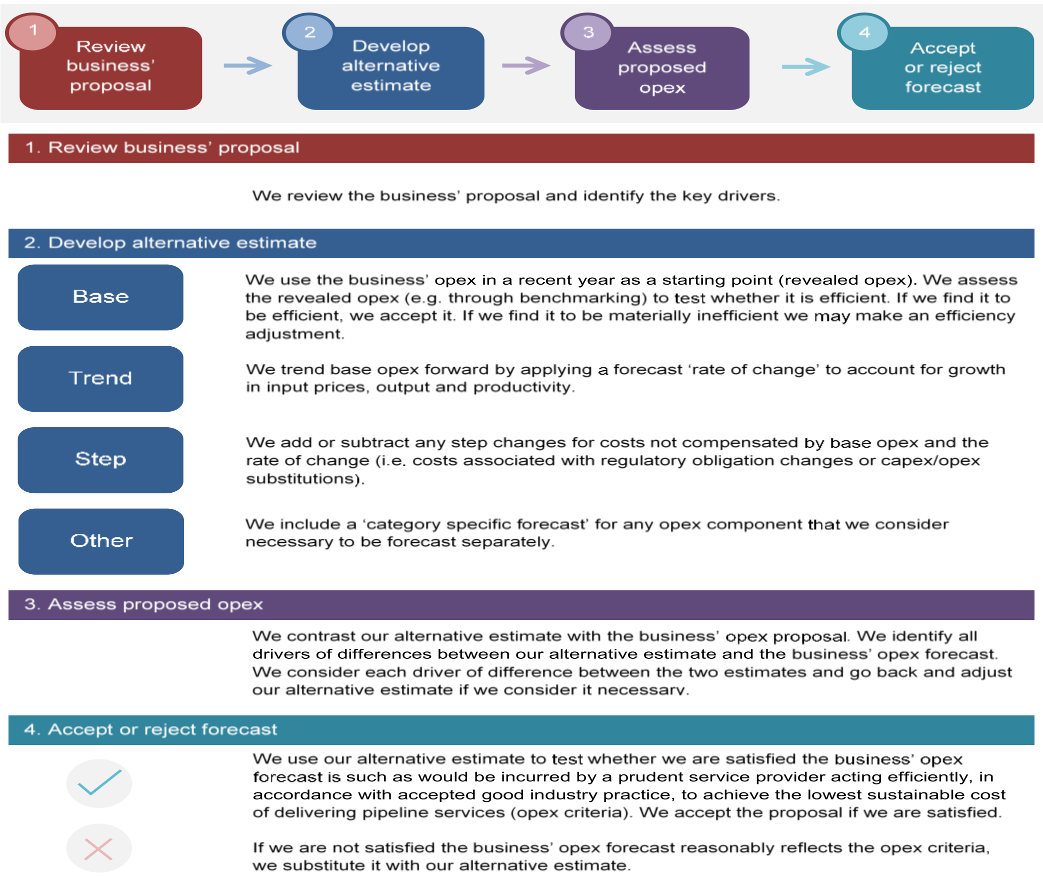
6.3.2 Building an alternative estimate of total forecast opex

As a comparison tool to assess a business' opex forecast, we develop an alternative estimate of the business' total opex requirements in the forecast period, using the base–step–trend forecasting approach. We apply the forecasting and estimate requirements under the NGR.[40]

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' forecast opex.

Figure 6.3 summarises the base–step–trend forecasting approach.

Figure 6.3 AER's opex assessment approach



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

[40] NGR, r. 74(2).

6.3.2.1 Base opex

If we find the business is operating efficiently, our preferred methodology is to use the business' historical or 'revealed' costs in a recent year as a starting point for our opex forecast.

We do not simply assume the business' revealed opex is efficient. It may include an ongoing level of inefficient expenditure. We use the business' actual opex in a single year as the starting point for our alternative estimate. This is the base opex.

We rely on the incentives under revenue regulation and any applicable efficiency incentive scheme to determine whether a business' 'revealed' opex is efficient.[41] We also assess the evidence the business submits to demonstrate the efficiency of its base opex.

To the extent that it is available, we may use benchmarking to test the efficiency of the base opex. Benchmarking is a way of determining how well a network business is performing against its peers and over time, and provides valuable information on what is 'best practice'.

If there are indications the business' revealed opex is inefficient, we may apply an efficiency adjustment to derive a base opex that complies with the opex criteria.

We consider revealed opex in the base year is generally a good indicator of opex requirements over the next access arrangement period because the level of *total opex* is relatively stable from year to year. This reflects the broadly predictable and recurrent nature of opex.

A business may experience fluctuations in particular categories of opex, and the composition of total opex can change, from year-to-year. While many operations and maintenance activities are recurrent and non-volatile, some opex projects follow periodic cycles that may or may not occur in any given year, and some opex projects are non-recurrent.

Even if disaggregated opex categories have high volatility, the total opex varies to a lesser extent because new or increasing components of opex are generally offset by decreasing costs or discontinued opex projects. Further, we expect the regulated business to manage the inevitable 'ups and downs' in the components of opex from year-to-year—to the extent they do not offset each other— by continually re-prioritising its work program, as would be expected in a workably competitive market. Our incentive-based, revealed cost, framework incentivises them to do so.

We also note that any volatility of total opex from year-to-year does not typically affect our choice of the appropriate base year when an ECM applies. A consequence of the operation of the ECM is that the forecast opex allowance (including ECM rewards and

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41 NGR, r. 71(1). We may infer opex is efficient without embarking on a detailed investigation, from the operation of an incentive mechanism.

penalties) is largely uninfluenced by the choice of base year. For example, although using a base year with unusually high opex would typically result in an increased opex forecast, this would be offset by a lower ECM reward (or a greater penalty).

If the business has demonstrated its ability to satisfy its obligations and service demand using its revealed costs, any further adjustments to base opex risk introducing a bias into the forecast—including through bottom-up type assessments. We therefore carefully scrutinise any such proposed adjustments.

6.3.2.2 Rate of change

We trend base opex forward by applying our forecast 'rate of change'. We estimate the rate of change by forecasting the expected growth in input prices, outputs and productivity. We consider that the rate of change takes into account almost all relevant sources of opex growth.

We forecast input price growth using a composition of labour and non-labour price change forecasts. To determine the input price weights for labour and non-labour prices, we have regard to the input price weights of a prudent and efficient benchmark business. Consistent with incentive regulation, this provides the business an incentive to adopt the most efficient mix of inputs throughout the access arrangement period but does not prevent the business from adopting its own mix of inputs.

We forecast output growth to account for the annual increase in output of services provided. The output measures used should, ideally, be the same measures used to forecast productivity growth. Productivity measures the change in output for a given amount of input. If the output measures differ from the productivity measures, they would be internally inconsistent and we cannot compare them like for like.

The output measures we typically use for gas distribution businesses are customer numbers, mains length, and energy throughput. We do not typically adjust forecast output growth for economies of scale because we account for these in our forecast of productivity growth.

Our forecast of opex productivity growth captures the sector-wide, forward-looking, improvements in good industry practice that should be implemented by efficient distributors as part of business-as-usual operations. For gas distribution, we generally base our estimate of productivity growth on recent productivity trends.

6.3.2.3 Step changes and category-specific forecasts

Lastly, we add or subtract any components of opex that are not adequately compensated for in base opex or the rate of change, but which should be included in the forecast total opex to meet the opex criteria. These adjustments are in the form of 'step changes' or 'category-specific forecasts'.

Step changes

Step changes should not double count costs included in other elements of the total opex forecast. For example, the costs of increased volume or scale should be compensated for through the output growth component of the rate of change and, as such, should not be accommodated through a step change. In addition, forecast productivity growth may account for the cost of increased regulatory obligations over time—that is, 'incremental changes in obligations are likely to be compensated through a lower productivity estimate that accounts for higher costs resulting from changed obligations.'[42] Therefore, we consider only new costs that do not reflect the historic 'average' change as accounted for in the productivity growth forecast require step changes.

To increase its opex forecast, a regulated business has an incentive to identify new costs not reflected in base opex or costs increasing at a greater rate than the rate of change. It has no corresponding incentive to identify those costs that are decreasing or will not continue. Information asymmetries make it difficult for us to identify those future diminishing costs. Therefore, simply demonstrating that a new cost will be incurred—that is, a cost that was not incurred in the base year—is not a sufficient justification for introducing a step change. There is a risk that including such costs would upwardly bias the total opex forecast.

The test we apply is whether the step change is needed for the opex forecast to comply with the opex criteria.[43] Our starting position is that only exceptional circumstances would warrant the inclusion of a step change in the opex forecast because they may change a business' fundamental opex requirements. Two typical examples are:

- a material change in the business' regulatory obligations
- an efficient and prudent capex/opex substitution opportunity.

We may accept a step change if a material 'step up' or 'step down' in expenditure is required by a network business to prudently and efficiently comply with a new, binding regulatory obligation that is not reflected in the productivity growth forecast. This does not include instances where a business has identified a different approach to comply with its existing regulatory obligations that may be more onerous, or where there is increasing compliance risks or costs, the business must incur to comply with its regulatory obligations. Often when a new regulatory obligation is imposed on a business, it will incur additional expenditure to comply. The business may be expected to continue incurring such costs associated with the new regulatory obligation into future access arrangement periods; hence, an increase in its opex forecast may be warranted.

We expect the business to provide evidence demonstrating the material impact the change of regulatory obligation has on its opex requirements, and robust cost–benefit analysis to demonstrate the proposed step change expenditure is prudent and efficient to meet the change in regulatory obligations.

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[42] AER, *Expenditure forecast assessment guideline, Explanatory statement*, November 2013, p. 52.

[43] NGR, r. 91.

By contrast, proposed opex projects designed to improve the operation of the business, which we consider as discretionary in the absence of any legal requirement, should be funded by base opex and trend components, together with any savings or increased revenue that they generate—rather than through a step change. Otherwise, the business would benefit from a higher opex forecast *and* the efficiency gains.

We may also accept a step change in circumstances where it is prudent and efficient for a network business to increase opex in order to reduce capital costs. We would typically expect such capex/opex trade-off step changes to be associated with replacement expenditure (or repex). The business should provide robust cost–benefit analysis to demonstrate clearly how increased opex would be more than offset by capex savings.

In the absence of a change to regulatory obligations or a legitimate capex/opex trade-off opportunity, we would accept a step change under limited circumstances. We would consider whether the costs associated with the step change are unavoidable and material—such that base opex, trended forward by the forecast rate of change, would be insufficient for the business to recover its efficient and prudent costs. We would also consider whether the business would continue to incur the costs of a proposed step change in future access arrangement periods.

Category specific forecasts

A category specific forecast is a forecast of an opex item or activity that is assessed and forecast independently from base opex, and is not subject to the ECM.

A category specific forecast may be justified if, as a result of including a specific opex category in the base opex, total opex becomes so volatile that it undermines our assumption that total opex is relatively stable and follows a predictable path over time.

We may also use category specific forecasts to avoid inconsistency or double counting within our regulatory decision. For example, we forecast debt raising costs separately to provide consistency with the forecast of the cost of debt in the rate of return building block of total revenue.

Absent such exceptions, we expect that base opex, trended forward by the rate of change, will allow the business to recover its prudent and efficient costs. This is a reasonable assumption given that the business has operated in the past with that level of opex, demonstrating that it is able to operate prudently and efficiently in meeting all its existing regulatory obligations, including its safety and reliability standards.

We consider it is also reasonable to expect the same outcome looking forward with the increase provided through the trend growth in the base opex. Some costs may go up, and some costs may go down—so despite potential volatility in the cost of certain individual opex activities, total opex is generally relatively stable over time.

For similar reasons as noted above in relation to step changes, we consider providing a category specific forecast for opex items identified by the business that may upwardly bias the total opex forecast. By applying our revealed cost approach consistently and carefully scrutinising any further adjustments, we avoid this potential bias.

6.3.3 Interrelationships

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

- the operation of the ECM in the 2016–21 access arrangement period, which provides 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 used to forecast output growth
- the impact of cost drivers that affect both forecast opex and forecast capex, including forecast labour price growth
- our assessment of 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 consumer engagement in developing its regulatory proposal.

6.4 Reasons for draft decision

Our draft decision is to not accept AGN's total opex forecast of $361.8 million ($2020–21), including debt raising costs, for the 2021–26 period.[44]

We are not satisfied AGN's forecast opex meets the opex criteria[45] and the requirements for forecasts and estimates.[46] We consider that some forecast inputs have not been arrived at on a reasonable basis or do not represent the best forecast or estimate possible in the circumstances.[47] Consequently, we are not persuaded that the resulting total opex forecast meets the opex criteria.[48]

We consider that our alternative estimate of total forecast opex of $333.8 million ($2020–21), including debt raising costs, for the 2021–26 period meets the opex criteria.

Our alternative estimate of total opex is $27.9 million ($2020–21), or 7.7 per cent, lower than AGN's opex forecast of $361.8 million ($2020–21), including debt raising costs, for the 2021–26 period.

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44 AGN, *Final Plan*: *Five year plan for our South Australian network, 2021–2026,* July 2020.

45 NGR, r. 91.

46 NGR, r. 74.

47 NGR, r. 91.

48 NGR, r. 74.

We set out AGN's opex forecast and our draft decision alternative opex estimate in Table 6.4.

Table 6.4 AER's draft decision on opex and AGN's proposed opex for the 2021–26 access arrangement period ($million, 2020–21)

	AGN's proposal	AER's alternative estimate	Difference
Based on reported opex in 2019–20	338.5	339.5	0.9
Base year adjustments	–48.6	–52.1	–3.5
2019–20 to 2020–21 increment	4.0	1.1	–2.9
Output growth	7.3	6.9	–0.4
Price growth	4.4	–1.4	–5.8
Productivity growth	–3.7	–3.4	0.2
Step changes	8.1	0	–8.1
Category specific forecasts	47.2	38.9	–8.3
Total opex (excluding debt raising costs)	**357.4**	**329.4**	**–27.9**
Debt raising costs	4.4	4.4	0.0
Total opex (including debt raising costs)	361.8	333.8	**–27.9**

Source: AGN, *Final Plan*: *Five year plan for our South Australian network, 2021–2026 – Supporting document – Proposal Opex model*, July 2020.

Note: Numbers may not add up to total due to rounding.

The main drivers for the differences are set out in section 6.1 and we discuss the components of our alternative estimate below. Full details of our alternative estimate are set out in our opex model, which is available on our website.

6.4.1 Base opex

This section provides our view on the prudent and efficient level of base opex that AGN would need for the safe and reliable provision of gas services over the 2021–26 regulatory control period.

We have used base opex of $57.7 million ($2020–21) for each year of the 2021–26 access arrangement period or $288.5 million over five years to form our alternative estimate of forecast opex.

This is lower than AGN's proposal of $58.0 million ($2020–21) each year or $290.0 million over five years due to:

- AGN's submitted proposal failed to remove provisions and debt raising costs from the base year opex.[49]
- we have also used the latest inflation forecasts published by the RBA available at the time of our assessment.[50] We consider these inflation forecasts are the best forecast possible in the circumstances because they are the most up-to-date information available at the time.[51]

Table 6.5 sets out our estimate of opex for 2019–20, which we explain further in the sections below.

Table 6.5 AER's forecast of base opex ($million, 2020–21)

	Our base opex
Reported 2019–20 opex (unadjusted for movements in provisions)	67.9
Remove reported movement in provisions	0.1
Reported 2019–20 opex	**67.9**
Add estimated change in opex between the base year and the final year	0.2
Estimated final year opex	68.1
Remove category specific forecasts	10.4
Base opex	**57.7**

Source: AER analysis

Note: Numbers may not add up to total due to rounding.

6.4.1.1 Proposed base year

We have used 2019–20 as the base year consistent with AGN's proposal. AGN's reported opex expenditure at time of submission has been calculated on three quarters of actuals with June quarter estimates. It is expected that AGN will submit an updated opex model to reflect 2019–20 actuals for the final decision.

Consistent with our preferred approach, we have used AGN's reported opex in 2019–20 of $67.9 million ($2020–21) as the starting point in determining our alternative estimate of total opex. We consider that the opex AGN reported in 2019–20 is a reasonable basis for forecasting total opex for the 2021–26 period.[52] The actual opex incurred in 2019–20 is moderately higher to the opex reported in 2018–19 driven by higher UAFG estimated expenditure and lower than the previous regulatory period which AGN explained is a result of the cost reductions realised through the 2017

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49 AGN, Response to *Information request 015 (Q1) – Base Year Opex (Public),* 03 September 2020.

50 RBA, *Statement on Monetary Policy—Appendix: Forecast*, August 2020.

51 NGR, r. 74(2).

52 NGR, r. 74.

merger with AGIG. [53] There is no evidence to suggest AGN's expenditure drivers will change materially in the forecast period compared to those in 2019–20.

We note the choice of base year not only affects our alternative opex estimate, but also our calculation of ECM carryover amounts.

6.4.1.2 Efficiency of AGN's opex

AGN is subject to the incentives of an ex ante regulatory framework, including the application of the ECM for opex. Typically, where a service provider is subject to these incentives, we are satisfied there is a continuous incentive for a service provider to make efficiency gains and it does not have an incentive to increase its opex in the proposed base year.[54]

We have also considered benchmarking undertaken by Economic Insights, which AGN commissioned to assess the efficiency of its base year expenditure.[55] Economic Insights considered that AGN's normalised real opex per customer is below the average of the five largest Australian Gas Distribution Businesses (GDB). Prior to normalisation AGN's average opex per customer was actually 35.6 per cent above the average of the largest five GDB's.[56] Economic Insights considers that AGN's higher opex per customer, when compared to the five largest GDB's can be fully explained by its smaller scale, lower customer density and differences in the other identified cost drivers.

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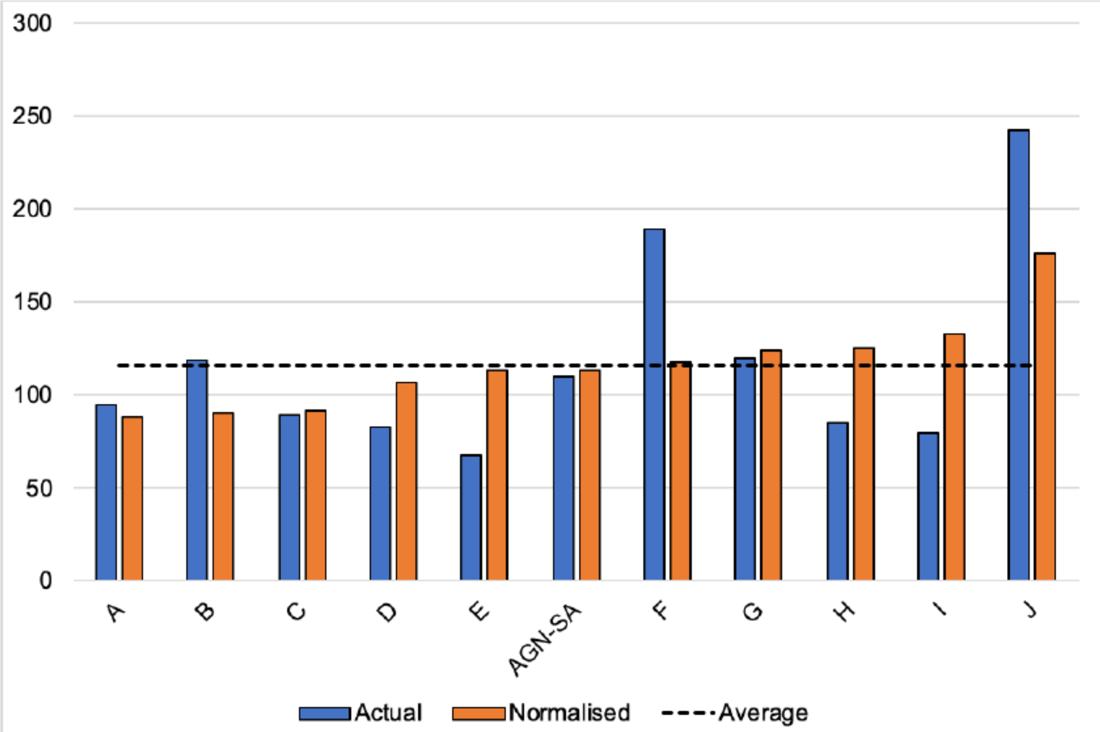
[53] AGN, *Final Plan*: *Five year plan for our South Australian network, 2021–2026,* July 2020, p. 7.

[54] NGR, r.71(1).

[55] AGN, *Final Plan*: *Five year plan for our South Australian network, 2021–2026 – Attachment 7.5 – EI Benchmarking opex and capex,* July 2020.

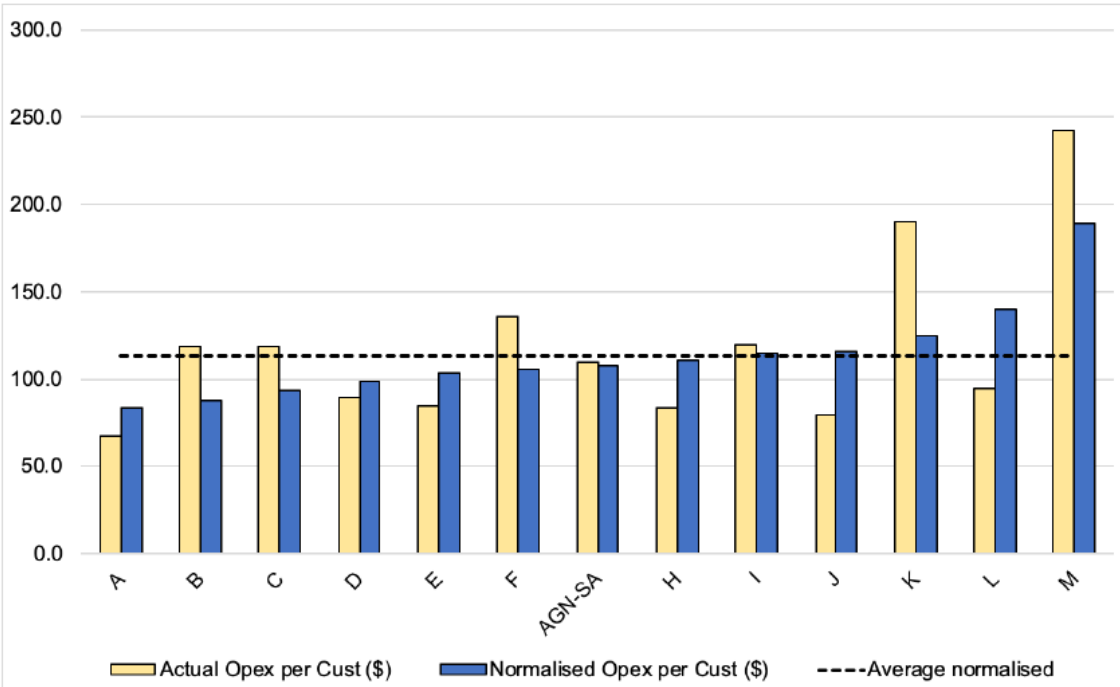
[56] AGN, *Final Plan*: *Five year plan for our South Australian network, 2021–2026 – Attachment 7.5 – EI Benchmarking opex and capex,* July 2020, p. 3.

Figure 6.4.1 Normalised Opex per Customer (2015–2019*) – 1st Method



Source: AGN, *Final Plan*: *Five year plan for our South Australian network, 2021–2026 – Attachment 7.5 – EI Benchmarking opex and capex*, July 2020, p. 22.

Figure 6.4.2 Normalised Opex per Customer (2015–2019*) – 2nd Method



Source: AGN, *Final Plan*: *Five year plan for our South Australian network, 2021–2026 – Attachment 7.5 – EI Benchmarking opex and capex*, July 2020, p. 23.

Benchmarking is a way of determining how well a network business is performing against its peers and over time, and provides valuable information on what is 'best practice'. We note that we do not do annual benchmarking analysis of gas distributors, like we do for electricity distributors. Nonetheless, numerous benchmarking studies have been done of gas distributors that provide useful insights.

Economic Insights stated that AGN appears to have performed at about an average level overall. When compared directly to the five largest GDB's it appears that cost per customer is higher than average. Economics Insights found that when the normalisation process was applied it clearly showed that this difference could be fully attributed to its smaller scale and lower customer numbers.

Economic Insights' findings suggest that AGN does not have any material inefficiency and does not require an adjustment to its base year opex. While Economic Insights' report refers to AGN's initially proposed base year of 2019–20, the analysis examines the historical efficiency performance of AGN over the period of 1999–2019.[57]

We agree with Economic Insights that the conclusions from its benchmarking analysis should be treated with care.[58] This analysis is limited by the small sample size of gas distribution businesses and it is difficult to test some of the underlying data sources—among other things.

Overall, our review of AGN's opex over time has not identified any significant inefficiencies. In the absence of any evidence suggesting to the contrary, we are satisfied that the 2019–20 base year opex is not materially inefficient.

Movements in provisions

We have removed the total movement in provisions of –\$0.1 million (\$2020–21) attributable to opex that AGN reported for 2019–20 in our alternative estimate of total opex. We typically assess base year expenditure exclusive of any movements in provisions so our alternative estimate is based on actual costs incurred by the business. This ensures that the reported opex amount we use for base opex is uninfluenced by the assumptions used to value provisions set aside for liabilities that have not yet been paid out.

In its opex forecast submitted in its Final Plan, AGN did not remove movements in provisions attributable to opex in 2019–20.[59]

For the purpose of this draft decision, we have used movements in provisions as reflected in the opex model as a placeholder until AGN submits its Annual Regulatory Information Notice (RIN). AGN noted that when it submits its 2019–20 annual RIN, it

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57 AGN, *Final Plan*: *Five year plan for our South Australian network, 2021–2026 – Attachment 7.5 EI Benchmarking opex and capex,* July 2020, p. 1.

58 AGN, *Final Plan*: *Five year plan for our South Australian network, 2021–2026 – Attachment 7.5 EI Benchmarking opex and capex,* July 2020, p. 4.

59 AGN, Response to *Information request 015(Q1) – Base Year Opex,* 03 September 2020.

will also provide updated and audited provisions amounts for 2019–20. We will take these into account in our final decision.

Estimate of 2020–21 opex

We need to estimate opex for the final year of the current (2016–21) period because we will not have a reported opex amount at the time of our final decision in April 2021. It is important our final year estimate is the same as that used in the ECM. This allows the service provider to retain incremental efficiency gains made after the base year through its opex forecast. We have estimated 2020–21 opex as follows:

$$A^*_{2020-21} = F_{2020-21} - (F_b - A_b) + non-recurrent\ efficiency\ gain_b$$

Where:

- $A^*_{2020-21}$ is the best estimate of actual opex for the final year of the 2016–21 period
- $F_{2020-21}$ is the allowed opex forecast for the final year of the 2016–21 period
- F_b is the allowed opex forecast for the base year, 2019–20
- A_b is the amount of reported opex in the base year, 2019–20
- $non-recurrent\ efficiency\ gain_b$ is the non-recurrent efficiency gain in the base year.

We have used 2019–20 as the base year and have not applied any adjustment for non-recurrent efficiency gains in the base year, consistent with AGN's proposal. Applying this approach, we have estimated actual opex of $57.7 million ($2020–21) for 2020–21.

6.4.2 Rate of change

Once we have estimated opex in the final year of the 2016–21 period, we apply a forecast annual rate of change to forecast opex for the 2021–26 period.

We have applied a forecast average annual rate of change of 0.41 per cent. This is lower than AGN's forecast of 0.96 per cent. We compare both forecasts in Table 6.6.

Table 6.6 AER's draft decision and AGN's proposed forecast annual rate of change in opex for the 2021–26 access arrangement period (per cent)

	2021–22	2022–23	2023–24	2024–25	2025–26
AGN's proposal					
Input price growth	0.44	0.48	0.59	0.54	0.48
Output growth	0.59	0.86	0.94	0.96	0.92
Productivity growth	0.40	0.40	0.40	0.40	0.40
Opex rate of change	**0.63**	**0.93**	**1.13**	**1.10**	**1.00**

	2021–22	2022–23	2023–24	2024–25	2025–26
AER's draft decision					
Input prices	–0.25	–0.36	–0.18	0.11	0.48
Output growth	0.59	0.86	0.95	0.97	0.92
Productivity growth	0.40	0.40	0.40	0.40	0.40
Opex rate of change	**–0.06**	**0.09**	**0.36**	**0.68**	**1.00**

Source: AER analysis; AGN, *Final Plan*: *Five year plan for our South Australian network, 2021–2026 – Attachment 7.1 – Proposal Opex model*, July 2021.

Note: The rate of change = (1+ price growth) × (1+ output growth) × (1+ productivity growth) – 1.

The difference between our forecast rate of change and AGN's is driven by:

- a different approach to forecasting labour price growth
- our incorporation of the legislated superannuation guarantee increases.

We discuss these issues below.

6.4.2.1 Forecast price growth

We have applied a real average annual price growth of –0.04 per cent to develop our alternative estimate of total opex. This decreased our total opex alternative estimate by $1.4 million ($2020–21). It compares to AGN's proposed average annual price growth of 0.51 per cent, which increased its total opex forecast by $4.4 million ($2020–21).[60]

Our real price growth forecast is a weighted average of forecast labour price growth and non-labour price growth:

- to forecast labour price growth, we have used the most up-to-date forecast of growth in the utilities WPI for SA, undertaken in August 2020, as forecast by our consultant, Deloitte.[61] This is a change to our standard approach of averaging the WPI growth forecasts provided by Deloitte and the consultant engaged by the business. This change reflects that the WPI forecasts submitted by AGN did not factor in the full economic impact of the COVID–19 pandemic
- both we and AGN applied a forecast non-labour real price growth rate of zero.[62]
- we and AGN have applied the same weights to account for the proportions of opex that is labour and non-labour, 59.7 per cent and 40.3 per cent, respectively.[63]

60 AGN, *Final Plan*: *Five year plan for our South Australian network, 2021–2026 – Supporting document – Proposal Opex model,* July 2020.

61 Deloitte Access Economics, *Labour price growth forecasts prepared for the Australian Energy Regulator*, August 2020.

62 AGN, *Final Plan*: *Five year plan for our South Australian network, 2021–2026,* July 2020, p. 79.

63 AGN, *Final Plan*: *Five year plan for our South Australian network, 2021–2026,* July 2020, p. 79.

Consequently, the key difference between our real price growth forecasts and AGN's reflects a change in our approach to forecasting labour price growth.

Accounting for the impact of the COVID-19 pandemic

To forecast labour price growth we have used our Deloitte only forecast WPI, made in August 2020,[64] because they reflect the only available forecast accounting for COVID-19 impact at this stage and would provide the best possible forecast of labour price growth in the circumstances[65].

AGN adopted our standard approach,[66] taking the average of the utilities WPI forecasts from Deloitte, made in June 2019[67] and their consultant, BIS Oxford Economics, made in February 2020.[68] Both forecasts provided by AGN were prepared prior to the COVID–19 pandemic, which has materially changed the economic outlook. As such, we do not consider our standard approach of averaging the Deloitte and BIS Oxford Economics' forecasts of WPI would produce the best possible forecast in the circumstances. In doing this, we considered stakeholders submissions which stated that we should take into account the impact of COVID-19 pandemic.

AGN have acknowledged that the WPI forecasts provided by their consultant BIS Oxford Economics are not reflective of the economic impacts resulting from COVID–19 and will be resubmitting updated forecasts.[69] If we have updated forecasts that account for the changed economic outlook in our final decision will reconsider using our standard approach having regard to the reasons set out above.

We have accounted for the legislated increases in the superannuation guarantee in our labour price growth forecasts

Under the *Minerals Resource Rent Tax Repeal and Other Measures Bill 2014 (Cth)*, Schedule 6— Superannuation Guarantee Charge percentage, the superannuation guarantee is scheduled to increase incrementally from 9.5 per cent on 1 July 2020 to 12 per cent on 1 July 2025.

AGN did not include an additional allowance for the legislated superannuation guarantee increases to its labour price growth forecasts. AGN's consultant, BIS Oxford Economics provided them with advice that they expect the proposed Superannuation Guarantee increases will be deferred due to current economic conditions as per the same reason they were deferred in 2014/15. [70] We note the concerns which have been raised in relation to the superannuation guarantee increase proceeding, particularly in

64 Deloitte Access Economics, *Labour price growth forecasts prepared for the Australian Energy Regulator*, August 2020.

65 NGR, r. 74(2)(b)).

66 AGN, *Final Plan*: *Five year plan for our South Australian network, 2021–2026,* July 2020, p. 78.

67 Deloitte Access Economics, *Labour price growth forecasts prepared for the Australian Energy Regulator*, June 2019.

68 BIS Oxford Economics, *Input cost escalation forecasts to 2025–26*, February 2020.

69 AGN, *Response to AER information request IR#007 – Forecast Price and Growth (Q1-3),* August 21.

70 AGN, *Response to AER information request IR#007 – Forecast Price and Growth (Q1-3),* 21 August 2020.

light of the economic impacts of the COVID-19 pandemic. However, as the superannuation guarantee increases are currently legislated in place we consider it is appropriate to consider how they should be factored into forecasts of labour price growth.

We sought advice from Deloitte on how to best account for the superannuation guarantee increases. It noted that there is extensive research suggesting that increases in payroll taxes or compulsory contributions levied on employers are passed onto employees. This research suggests that the increases to the superannuation guarantee will likely result in slower WPI growth than would otherwise have been the case. Deloitte advised that the superannuation guarantee increases should be added to the forecast WPI growth rates, but only if those WPI growth rates take into account the superannuation guarantee changes.[71] Consequently we have added the legislated superannuation guarantee increases to Deloitte's WPI growth forecasts to forecast labour price growth.[72]

6.4.2.2 Forecast output growth

We have adopted AGN’s approach to forecast output growth. We forecast average annual output growth of 0.86 per cent. This increases our alternative estimate of total opex by $6.9 million ($2020–21). This compares with 0.85 per cent proposed by AGN, which increases its proposed opex by $7.3 million ($2020–21).

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

To assess AGN’s output and productivity growth forecasts, we tested whether output growth, net of productivity growth, falls within an acceptable range based on the results of previous econometric studies. The acceptable range is based on the cost functions estimated by Economic Insights[73] and ACIL Allen.[74] We consider this approach uses the best information available to establish an acceptable range.

When we tested AGN's forecast average annual output growth net of productivity growth against the acceptable range of forecast output growth, it fell within the acceptable range. The results are set out in Table 6.7.

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[71] Deloitte Access Economics, *Impact of changes to the superannuation guarantee on forecast labour price growth*, 24 July 2020, p. 4.

[72] Deloitte Access Economics, *Impact of changes to the superannuation guarantee on forecast labour price growth*, 24 July 2020, pp. 4–5.

[73] Economic Insights, *Productivity performance,* Report for AGN, July 2020; Economic Insights, *Gas Distribution Businesses Opex Cost Function, Report prepared for Multinet Gas*, 22 August 2016.

[74] ACIL Allen Consulting, *Opex Partial Productivity Analysis, Report for AGN*, 20 December 2016; ACIL Allen Consulting, *Opex Partial Productivity Study, Report for AGN*, July 2020.

Table 6.7 Comparison of AGN's forecast output growth with the acceptable range of output growth net of productivity

	Proposed average annual growth rate, per cent	Acceptable range, average annual growth rate, per cent	Assessment
AGN	0.45	–1.40 to 0.71	Within acceptable range

Source: AER analysis.

6.4.2.3 Forecast productivity growth

We have adopted AGN's proposed annual productivity growth rate of 0.40 per cent.[75] This decreases our alternative opex estimate by $3.4 million ($2020–21) for the 2021–26 period.

We consider network growth should deliver productivity gains such as economies of scale, particularly for operating costs.

Achieving productivity gains would be consistent with AGN's past performance as well as that of other gas distribution businesses. According to the productivity performance study Economic Insights prepared for AGN, opex partial factor productivity index performance improved from 1999 to 2019.[76]

We have also considered Economic Insights' econometric analysis. Economic Insights found significant economies of scale, as well as positive technological change. Both economies of scale and technological change are components of productivity change and they indicate the gas distribution businesses should achieve positive productivity growth, to the extent that output is forecast to grow.

6.4.3 Step changes

We have not included any step changes in our alternative estimate of opex. AGN proposed three step changes, totalling $8.1 million ($2020–21), for:

- a customer relationship management system
- a vulnerable customer assistance program
- insurance.

The first two of these proposed step changes were for new activities that AGN developed in response to feedback through its customer and stakeholder engagement program. We discuss below how we accounted for customer and stakeholder feedback within our assessment of opex step changes. We then discuss our assessment of each of the individual proposed step changes.

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75 AGN, *Final Plan: Five year plan for our South Australian network, 2021–2026,* July 2020, p. 80.

76 Economic Insights, *Productivity performance,* Report for AGN, July 2020, p. 24.

6.4.3.1 How we accounted for customer feedback

The main driver of the customer relationship management system and vulnerable customer assistance program step changes proposed is the customer and stakeholder engagement program undertaken by AGN. This is not one of the typical step change drivers, such as a material change in business regulatory obligations or a prudent and efficient capex/opex substitution, which we have previously recognised.

As set out in our assessment approach in 6.3.2, the test we apply is whether additional opex is needed for the opex forecast to comply with the opex criteria. In the NGR the opex criteria require ‘operating expenditure must be such as would be incurred by a prudent service provider activing efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services’.[77]

As noted in our recent draft decisions for the Victorian electricity distributors for 2021–26, we consider proposals which have been developed in consultation with consumers, are more likely to be in the long-term interests of consumers than those which have not.[78] In this case AGN has proposed new and enhanced services. In applying the opex criteria we have considered whether the enhancements reasonably reflect consumer preferences.

Factors we considered in forming a view about the customer engagement outcomes include whether:

- the consumer engagement involved a representative group of unbiased customers across relevant demographics
- the nature of the engagement was genuine, with customers being highly engaged and given the necessary support to provide informed views
- consumers were appropriately consulted and given a range of genuine options
- the initiative or project proposed by the network service provider in the proposal is clearly based on the expressed view of consumers
- consumers clearly understood the potential price impacts and there is support from vulnerable customers and a majority of other customer groups.

These factors are a starting point and we expect that our approach to the consideration of customer preferences will continue to evolve in future determinations.

Our assessment of AGN’s approach to consulting with its customers and other stakeholders is outlined in the overview. Overall we found that AGN’s consumer engagement was well received by stakeholders and met the factors above. We agree

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77 NGR, r. 91(1).

78 See for example AER, *Draft Decision, Powercor distribution determination 2021–26, Overview*, September 2020, pp. 44–45.

with CCP24 'that AGN has a strong track record for genuine and effective customer and stakeholder engagement'.[79]

In its advice to us CCP24 stated that consumers look to the AER to interpret the rules and how they should be applied and to assess the efficient cost of an initiative they may support.[80] In other words, once we are satisfied that consumers support a specific initiative, our role is to determine whether the proposal is prudent and efficient. We agree with this approach set out by CCP24.

To this end, in addition to being satisfied a proposed initiative is valued and supported by customers, to satisfy the opex criteria we must consider the prudency and efficiency of the costs and whether the opex forecast already compensates the business for the proposed new activity.

It is inevitable that the way in which a gas distributor provides its services, and the specific activities it undertakes, will evolve over time. We have therefore considered whether the opex required to deliver a customer supported initiative might be captured within the rate of change. We consider the forecast rate of change, including forecast productivity growth, will provide for incremental changes in the services provided. Consequently we consider additional opex, beyond that provided by the forecast rate of change, would only be required for significant discrete changes.

Similarly, we would expect changes in good industry practice to improve the quality of services delivered, for example, by improving safety and reliability. We consider that productivity growth, included in the rate of change, will account for the change over time in good industry practice. If proposed improvements in service quality are consistent with historical improvements, additional opex may not be required.

However, if a proposed customer supported initiative delivers a significant improvement in the quality of service this may not be not captured in the output specification used to forecast output growth. In that case the forecast rate of change may not account for the increase in outputs. If customers are willing to pay more for the increased outputs than it costs to deliver them, then it may be prudent and efficient to undertake the proposed initiative. If this is the case, we would need to be satisfied that proposed customer supported initiative delivers a genuine step increase in the quality of the service being provided.

We have also considered how a customer supported initiative that is prudent and efficient, and is not accounted for in base opex or the rate of change, should be accounted for in forecast opex. If we provide the additional opex for a customer supported initiative as a step change, we effectively provide the additional annual expenditure in perpetuity. The efficiency carryover mechanism rewards AGN for

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[79] CCP24, *CCP24 Advice to Australian Energy Regulator on Australian Gas Networks Customer initiated opex programs*, 6 October 2020, p. 8.

[80] CCP24, *CCP24 Advice to Australian Energy Regulator on Australian Gas Networks Customer initiated opex programs*, 6 October 2020, p. 8.

reducing expenditure, including by reducing services. Typically regulatory obligations require networks to provide specified services and meet safety and other obligations. In the case of customer initiated services, no such obligations exist and these components of the service provided are not reflected in service quality incentives. Hence, the network would have the option of discontinuing the service at any time.

Given this, we have considered whether providing a step change is the best way to provide additional opex to deliver a customer supported initiative. Instead, we consider the additional opex for the activity should be provided as a category specific forecast and excluded them from the ECM. This would reduce the incentive to discontinue the initiative. In this case, if AGN discontinues the customer supported initiative it will only retain the avoided opex for the remainder of the access arrangement period. Further, in order to retain funding for the initiative in future reset periods, AGN would need to demonstrate that it will continue to deliver the initiative and that customers continue to value it.

6.4.3.2 Customer relationship management system

We have not included AGN's proposed step change for a new customer relationship management system in our alternative estimate of opex, either as a step change or a category specific forecast. AGN's customer engagement found there was strong support from customers for this project. However, we are not satisfied that additional opex is required to deliver additional online services to customers.

AGN proposed the 'digital customer experience project' as a step change, totalling $1.4 million ($2021–21). AGN stated that customers expect its communication channels and service options to reflect broader market trends, which increasingly means offering a variety of digital communication channels.[81]

AGN stated that it currently communicated planned maintenance by letter box drops which it stated are often mistaken for junk mail and left unread. Similarly, communications about meter changes and resolving meter reading issues are facilitated through a physical card being left at the door. AGN stated that both of these communication methods can result in customers being unaware of the works to be done at their premises or in their local community.[82]

The proposed step change would update AGN's website to provide self-service options. This would include:

- interactive maps displaying outages and planned works
- online registration for outage notifications
- connection request portal which provides status updates

[81] AGN, *Final Plan*: *Five year plan for our South Australian network, 2021–2026,* July 2020, p. 79.

[82] AGN, *Final Plan*: *Five year plan for our South Australian network, 2021–2026 - Attachment 8.8, Capex business cases, Part 5,* July 2020, p. 422.

- online registration of vulnerability
- submission of self-read meter data online.[83]

We sought advice from CCP24 on its assessment of AGN's engagement on the proposed digital customer experience step change. This included the nature of engagement, its breadth and depth, clear evidence of its impact and CCP24's assessment of the outcomes. CCP24 advised that it considered:

- all participants were actively engaged in the workshop sessions
- the presented options were clearly explained and well understood by participants
- the process was robust and lead by an independent facilitator with AGN staff available for questions of detail
- the alternatives provided were clear and that no change was presented as a viable option
- there was agreement to the proposition that AGN should deliver more services through digital channels
- the fact that no submissions to the AER mentioned the proposed customer relationship management system step change, suggested there is no opposition to it nor to the engagement that led to it.[84]

In conclusion CCP24 stated that:[85]

> The available evidence shows that there is strong residential and small business consumer support for the "digital experience" expenditure proposed by AGN in their Access Arrangement proposal. We are unaware of any opposition from other stakeholders or customer groups. In CCP24's opinion, the outcomes of AGN's consumer engagement support the proposed digital customer experience project.

Having considered AGN's proposal, and the advice from CCP24, we are satisfied that AGN undertook robust consumer consultation and the consulted customers supported the provision of improved online services. However, we also need to consider whether the total opex forecast, without including the proposed step change, is sufficient to provide the proposed additional services that customers say they value.

We are not satisfied that the proposed customer relationship management system step change is material. The proposed step change is for $1.4 million ($2020–21), or 0.4 per cent of AGN's total opex forecast. We also consider the net cost will be less

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83 AGN, *Final Plan*: *Five year plan for our South Australian network, 2021–2026 - Attachment 8.8, Capex business cases, Part 5,* July 2020, pp. 431, 434.

84 CCP24, *CCP24 Advice to Australian Energy Regulator on Australian Gas Networks Customer initiated opex programs*, 6 October 2020, pp. 9–12.

85 CCP24, *CCP24 Advice to Australian Energy Regulator on Australian Gas Networks Customer initiated opex programs*, 6 October 2020, p. 12.

than this because the project will reduce other costs incurred by AGN. For example, we would expect providing more information to customers on its website will reduce the number of calls received by AGN's call centre.

We consider that the costs are not additional to the trend costs for the efficient benchmark. Rather we consider the proposed service improvements to be a refinement of the services it currently provides and is consistent with the gradual improvement of good industry practice that we consider is compensated for through the forecast rate of change. This is consistent with AGN's statement that 'customers expect its communication channels and service options to reflect broader market trends'. Similarly, we note that some gas distributors already provide similar services on their websites. For example, Jemena Gas Networks provides an outages map on its website and has made this improvement without a step change or additional category specific forecast.

Given these considerations we are not satisfied that additional opex is required to deliver the proposed customer relationship management system. We consider that our total opex forecast, including base opex and the forecast rate of change, provide sufficient opex. We are satisfied, however, that the initiative has received support from customers. AGN should respond to its customers' feedback that it should broaden its communication channels and service options to reflect broader market trends.

6.4.3.3 Vulnerable customer assistance program

We have not included AGN's proposed step change for a vulnerable customer assistance program in our alternative estimate of opex for this draft decision. Neither have we included it as a category specific forecast.

AGN's customer engagement process revealed strong support for a vulnerable customer assistance program. However, we require further information to be satisfied that we should include additional opex for the vulnerable customer assistance program in our alternative estimate of opex. We will reconsider this in our final decision if AGN provides further information demonstrating that the program will deliver a materially higher level of service. Further co-design of the proposal with stakeholders to address, for example, concerns about potential overlaps of the proposal would help inform the final decision.

The proposed vulnerable customer assistance program was a result of AGN engaging with its customers and stakeholders, including a series of co-design workshops.[86]

The vulnerable customer assistance program would provide:

- a dedicated resource to run the program
- assistance for appliance rebates and audits for vulnerable customers

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[86] AGN, *Final Plan*: *Five year plan for our South Australian network, 2021–2026,* July 2020, p. 78.

- rebates for new connections
- rebates for switching to more efficient gas appliances
- gas efficiency audits
- CRM enhancements for improved/targeted services.[87]

We sought advice from CCP24 on its assessment of AGN's engagement on the proposed vulnerable customer assistance program step change. This included the nature of engagement, its breadth and depth, clear evidence of its impact and CCP24's assessment of the outcomes. CCP24 advised that:

- it was noteworthy that the impetus for a vulnerable customer assistance program arose from participant feedback during the initial round of customer workshops
- AGN hosted a series of three vulnerable customer assistance program co-design workshops, which lead to the set of potential new initiatives identified in AGN's *Draft plan*
- feedback on the vulnerable customer assistance program proposal was sought through submissions to the *Draft plan*, and through the third round of customer workshops
- 76 per cent of participants at these workshops, supported or strongly supported a vulnerable customer assistance program at a cost of $1 to $2 per annum on their bill (for residential consumers). AGN's customer reference groups were also supportive, but requested more information be provided in the *Final plan*.
- the *Final plan* identified the specific initiatives to be included in the vulnerable customer assistance program and the associated cost
- it considered that the customer workshops involved a fair representation of South Australian residential and small business gas consumers
- a number of stakeholders, have requested additional clarity on issues such as:
    - the scope of the program
    - respective roles of AGN, retailers, government and other support agencies
    - cost sharing arrangements
    - forecast bill impacts for medium and large businesses.
- AGN worked collaboratively with a group of 10 representatives with expertise in recognising and addressing the needs of vulnerable community members. AGN and co-design workshop participants canvassed and analysed approximately 100 options, before narrowing the initiatives down to those put forward in the *Final plan*.[88]

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87 AGN, *Final Plan*: *Five year plan for our South Australian network, 2021–2026,* July 2020, p. 78.

88 CCP24, *CCP24 Advice to Australian Energy Regulator on Australian Gas Networks Customer initiated opex programs*, 6 October 2020, pp. 9–12.

In conclusion CCP24 stated that:[89]

> In CCP24's opinion, the outcomes of AGN's consumer engagement support the proposed VCAP in principle, with a number of stakeholders seeking further clarification of project details prior to lodgement of the revised AA.

Having considered AGN's proposal, and the advice from CCP24, we are satisfied that AGN undertook robust consumer consultation and the consulted customers supported the provision of a vulnerable customer assistance program.

However, it is not yet clear whether or not the total opex forecast, without including the proposed step change, is sufficient to provide the proposed additional services that customers value. To be satisfied of this we require further information showing that the proposed vulnerable customer assistance program would materially increase the quantity or quality of services it provides. In particular we note that AGN already offers rebates for new connections and rebates for gas appliances.[90] AGN needs to clearly differentiate the activities it proposes to undertake as part of the vulnerable customer assistance program from its marketing activities.

Similarly, AGN will need to demonstrate that the vulnerable customer assistance program is discrete and measureable. If we are to provide additional opex for the program we consider it should be provided as a category specific forecast and the program should be excluded from the ECM. To do this AGN will need to be able to separately report the costs of delivering the program.

Given these considerations we have not included additional opex for the proposed vulnerable customer assistance program in our alternative estimate of opex for this draft decision. We are satisfied, however, that customers support providing assistance to vulnerable customers. We encourage AGN to undertake further co-design with stakeholders and provide further information in support of the vulnerable customer assistance program in its revised proposal. We will carefully consider any such information in making our final decision.

6.4.3.4 Insurance

We have not included AGN's proposed step change for an incremental increase on their insurance premiums in our alternative estimate. Our decision is consistent with

[89] CCP24, *CCP24 Advice to Australian Energy Regulator on Australian Gas Networks Customer initiated opex programs*, 6 October 2020, p. 15.

[90] https://www.australiangasnetworks.com.au/gas-explained/benefits-of-natural-gas/customer-rebates-and-promotions.

our recent decisions for South Australian Power Networks[91] and the Victorian distributors.[92]

AGN has proposed a $2.9 million step change for incremental increases to insurance premiums over the next regulatory control period.[93] AGN commissioned Marsh to assess the global insurance market and provide advice on the expected movements of insurance premiums.[94]

We have assessed the insurance premium step change and are not satisfied that a step change is warranted. We consider the increasing insurance costs would be captured through price growth. Our trend forecast includes an allowance for increases in non-labour price growth by CPI. We expect some non-labour components in opex will increase by more than CPI and some less than CPI. To the extent that higher insurance premiums rise by more than CPI, we expect this will to an extent be offset by other non-labour costs rising by less than CPI.

The proposed insurance premium increases are not related to a new regulatory obligation or a capex/opex substitution, the most common circumstances for which we consider allowing a step change. We also do not consider that the circumstances that AGN faces in the insurance liability market for one of its cost inputs is sufficiently exceptional that it would materially change its total opex over time beyond what is captured through our price growth forecast.

6.4.4 Category specific forecasts

We have included category specific forecasts for two expenditure items in our alternative estimate of total opex for the 2021–26 period. We have not forecast these costs using the base-step-trend approach. These are debt raising costs and UAFG. Table 6.8 sets out the forecasts AGN included in its total opex forecast. We are not satisfied that the UAFG amounts represent the best forecast possible in the circumstances, particularly in relation to forecast UAFG volumes, and have included our revised forecasts in our alternative opex estimate.

We note that AGN's engagement found that its customers had a preference for purchasing a portion of its replacement gas from renewable sources. If AGN decides to purchase renewable replacement gas in line with its customers' preferences and incurs an additional cost, this can be recovered through the tariff variation mechanism in its access arrangement.

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91 AER, *Final Decision, SA Power Networks distribution determination 2020–25 – Attachment 6 Operating Expenditure,* June 2020, pp. 26–29.

92 AER, *Draft Decision Powercor distribution determination 2021-26 – Attachment 6 Operating Expenditure,* September 2020, p. 56; AER, *Draft Decision United Energy distribution determination 2021-26 – Attachment 6 Operating Expenditure,* September 2020, p. 58.

93 AGN, *Final Plan*: *Five year plan for our South Australian network, 2021–2026- Supporting document - – Attachment 7.1 – Opex forecast model (Public),* July 2020.

94 AGN, *AGN Attachment 7.7 Marsh Insurance AA report (Public*), 1 July 2020.

Table 6.8 AER's draft decision and AGN's proposed category specific opex forecasts for the 2021–26 access arrangement period ($million, 2020–21)

Category	AGN's proposal	AER's draft decision	Difference
Debt raising costs	4.4	4.4	**0.0**
UAFG	47.2	38.9	**–8.3**
Total	**51.6**	**43.3**	**–8.3**

Source: AGN, *Response to AER information request 019 – UAFG Allowances*, 13 October; AER analysis.
Note: Numbers may not add up to total due to rounding.

6.4.4.1 Debt raising costs

We have included debt raising cost of $4.4 million ($2020–21) in our alternative opex forecast for the 2021–26 period.

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 for consistency with the forecast of the cost of debt in the rate of return building block. We discuss this in Attachment 3 of this draft decision.

6.4.4.2 Unaccounted for gas

Unaccounted for gas (or 'UAFG') is the difference between the measured quantity of gas entering the network system (gas receipts) and metered gas deliveries (gas withdrawals).[95] It may be attributable to gas leakage, inaccuracies in gas measurement or gas theft. AGN is required to replace any UAFG.[96]

AGN's access arrangement allows for UAFG costs to be recovered and includes an incentive to minimise UAFG. If the actual UAFG rate is below (above) AGN's target UAFG rate, AGN over (under) recovers its actual UAFG costs. If the price of purchasing UAFG differs from the approved forecast, AGN is compensated through the tariff variation mechanism.

AGN proposed a $47.2 million ($2020–21) for UAFG over the 2021–26 regulatory period. We do not accept this cost forecast in our alternative estimate of forecast total opex for the 2021–26 period. We consider the forecast is not arrived at on a reasonable basis and it does not represent the best forecast possible in the circumstances. We have instead included $38.9 million ($2020–21) in our alternative estimate.

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[95] AGN, *Final Plan*: *Five year plan for our South Australian network, 2021–2026,* July 2020, p. 82.

[96] AGN, *Response to AER Information Request 019 (Q5) – UAFG Allowances,* 13 October 2020, p. 1.

Table 6.9 sets out our draft decision on UAFG costs for each year of the 2021–26 period.

Table 6.9 Forecast UAFG costs ($million, 2020–21)

	2020–21	2021–22	2022–23	2023–24	2024–25	Total
AGN's proposal	9.4	9.4	9.4	9.4	9.4	**47.2**
AER's draft decision	7.8	7.8	7.8	7.8	7.8	**38.9**
Difference	–1.7	–1.7	–1.7	–1.7	–1.7	**–8.3**

Source: AGN, *Final Plan*: *Five year plan for our South Australian network, 2021–2026 – Supporting document – Proposal Opex model*, July 2020; AER analysis.

Note: Numbers may not add up to total due to rounding.

Consistent with the approach we adopted in our 2016–21 decision for AGN and AGN's 2021–26 proposal, we have forecast UAFG cost as the product of:[97]

- UAFG volumes
- the cost of replacement gas.

AGN used the same approach in its current proposal. There is no difference in the methodology to calculate UAFG costs. The variation between AGN's forecast of $47.2 million ($2020–21) and our forecast of $38.9 million ($2020–21) of UAFG costs is due to the difference in estimating volumes and the cost of replacement gas. We discuss each of these below.

UAFG volumes

AGN proposed a forecast of UAFG volumes based on a three year average of actual UAFG for 2015–16, 2016–17 and the estimate for 2017–18.[98] We engaged Zincara to review the reasonableness of the UAFG forecast.[99] We agree with Zincara's recommendation to use a forecast of UAFG based on a two year average of UAFG 2016–17 settled volumes and 2017–18 volumes which are almost settled.[100] This forecast factors the impact of AGN's recent mains replacement program on reducing UAFG volumes while still providing AGN an incentive to reduce UAFG volumes in future.

Due to the commercially sensitive nature of forecast UAFG volumes and prices, our detailed reasons in relation to UAFG volumes are set out in confidential Appendix A.

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97 AGN, *Final Plan*: *Five year plan for our South Australian network, 2021–2026,* July 2020, p. 82.

98 AGN, *Final Plan*: *Five year plan for our South Australian network, 2021–2026,* July 2020, p. 82.

99 Zincara, *Review of AGN Unaccounted for Gas – Public Summary,* November 2020.

100 Zincara, *Review of AGN Unaccounted for Gas – Public Summary,* November 2020, pp. 4–5.

The cost of replacement gas

We have forecast the cost of replacement gas based on the prices AGN was offered through a competitive tender. In developing our forecast costs, we have used the latest price information provided recently by AGN.[101] We consider this approach is reasonable and note that the actual cost of replacement gas will be 'trued-up' each year as part of the tariff variation process. We discuss our consideration of AGN's proposed reference tariff variation mechanism in attachment 10.

The price we have used is based on the assumption that AGN will not source any of its replacement gas from renewable sources. AGN, however, proposed to purchase of up to 20 per cent of its UAFG replacement gas from renewable gas sources. AGN's proposal to purchase up to 20 per cent of its unaccounted for gas from renewable gas sources followed its customer and stakeholder engagement where 87 per cent of customers considered it very important or extremely important that it consider ways to lower carbon emissions.[102] We discuss in section 6.4.3.1 above how we have accounted for customer feedback in our assessment of AGN's total opex forecast.

We sought advice from CCP24 on its assessment of AGN's engagement on the proposed purchase of renewable gas to replace unaccounted for gas. This included the nature of engagement, its breadth and depth, clear evidence of its impact and CCP24's assessment of the outcomes.

In summary, CCP24 considered the available evidence suggests that there is strong residential and small business consumer support, and no strong opposition from other consumer classes, for the proposal to source 20 per cent of replacement gas from renewable sources. CCP24 considered the outcomes of AGN's consumer engagement supported the proposed purchase of renewable unaccounted for gas.[103]

As noted by CCP24, we have received limited comment on this issue in submissions. SACOSS noted that consumers were supportive of sourcing renewable replacement gas only to the extent it increases bills up to a certain amount. Given this, it sought an assurance that consumers would not unnecessarily bear the risk of the cost of renewable replacement gas exceeding the incremental price at which customers expressed support.[104] The SA Government was supportive in principle but wanted us to do a thorough assessment of the gas price forecasts to ensure they were as accurate as possible.[105]

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[101] AGN, *Response to AER Information Request 019 – SA141 UAFG renewable business cases (Confidential),* 10 October 2020.

[102] AGN, *Final Plan*: *Five year plan for our South Australian network, 2021–2026,* July 2020, p. 82.

[103] CCP24, *CCP24 Advice to Australian Energy Regulator on Australian Gas Networks Customer initiated opex programs*, 6 October 2020, p. 19.

[104] SACOSS, *Submission to the AER on AGN's Access Arrangement Proposal for the South Australian gas distribution network (July 2021 – June 2026)*, 11 August 2020, p. 8.

[105] SA Minister Energy and Mining, *Submission on AGN 2021-26 AA Proposal*, 3 August 2020, p. 4.

CCP24 also noted that its observations were concentrated on residential and small business customers. It observations of larger customer views were limited to the South Australian Stakeholder Reference Group and reviewing the submissions from Business SA. It noted the Business SA submission made no specific comments on the use of renewable gas for UAFG.[106]

Having considered the advice from CCP24, and the submissions we have received we are satisfied that customers support the purchase of renewable gas by AGN to replace up to 20 per cent of its unaccounted for gas. While we have not included the cost of renewable gas in setting the cost of replacement gas, we consider the tariff variation mechanism in its access arrangement provides sufficient flexibility for AGN to source a portion of its UAFG from renewable gas in accordance with the expressed views of its customers. We encourage AGN to consider how it might provide some kind of assurance to its customers that they would not unnecessarily bear the risk of the cost of renewable replacement gas exceeding the incremental price at which customers expressed support.

6.5 Revisions

We require the following revisions to make the access arrangement proposal acceptable:

Table 6.10 AGN's opex revisions

Revision	Amendment
Revision 6.1	Make all necessary amendments to reflect our draft decision on the proposed opex allowances for the 2021–26 access arrangement period, as set out in section 6.1.

[106] CCP24, *CCP24 Advice to Australian Energy Regulator on Australian Gas Networks Customer initiated opex programs*, 6 October 2020, pp. 17–19.

Shortened forms

Shortened form	Extended form
AER	Australian Energy Regulator
capex	Capital expenditure
CAM	Cost allocation methodology
CESS	Capital expenditure sharing scheme
CCP24	Consumer Challenge Panel, sub-panel 24
CPI	Consumer price index
EBSS	Efficiency benefit sharing scheme
ECM	Efficiency carryover mechanism
NER	National Electricity Rules
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
opex	Operating expenditure
PTRM	Post-tax revenue model
RBA	Reserve Bank of Australia
RIN	Regulatory Information Notice
RFM	Roll forward model
RPP	Revenue and pricing principles
TAB	Tax asset base
UAFG	Unaccounted for gas
WACC	Weighted average cost of capital
WPI	Wage price index