Draft Decision

Australian Gas Networks (Victoria and Albury)
Access Arrangement 2023 to 2028

(1 July 2023 to 30 June 2028)

Attachment 6
Operating expenditure

December 2022

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 (Victoria and Albury) (AGN) for the 2023–28 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

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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 Australian Gas Networks' (AGN's) proposed opex forecast for the 2023–28 access arrangement period.

6.1 Draft decision

Our draft decision is to accept AGN's total opex forecast of $477.5 million ($2022–23), excluding ancillary reference services (ARS) and including debt raising costs.[1] This is because our alternative estimate of $470.0 million ($2022–23) is not materially different ($7.5 million ($2022–23), or 1.6% lower) from AGN's total opex forecast proposal. Therefore, we consider that AGN's total opex forecast satisfies the opex criteria,[2] and satisfies the criteria for forecasts and estimates.[3]

Our draft decision is:

- $85.4 million ($2022–23) (or 21.8%) higher than the opex forecast we approved in our final decision for the 2018–22 period
- $100.8 million ($2022–23) (or 26.7%) higher than AGN's actual (and estimated) opex in the 2018–22 period

After its initial proposal in July 2022, AGN submitted an addendum in September 2022 to reflect changes to estimates following release of the Victorian Government's *Gas Substitution Roadmap.* From an opex perspective, this primarily impacted the trend forecasts including AGN's output and productivity growth forecasts. We have considered this updated proposal, and the opex forecast it contained, in making our draft decision to accept the proposed opex forecast.

Table 6.1 sets out AGN's updated opex proposal, our alternative estimate for the draft decision and the differences between these forecasts.

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1 AGN, *2023–28 Revisions to final plan – Attachment 8.1A – Opex Forecast Model*, September 2022.These costs reflect those in the updated initial proposal AGN submitted on 2 September 2022 and as with all subsequent opex costs are in $2022–23.

2 NGR, r. 91.

3 NGR, r. 74.

Table 6.1 AER's alternative estimate compared to AGN's updated opex proposal ($million, 2022–23)

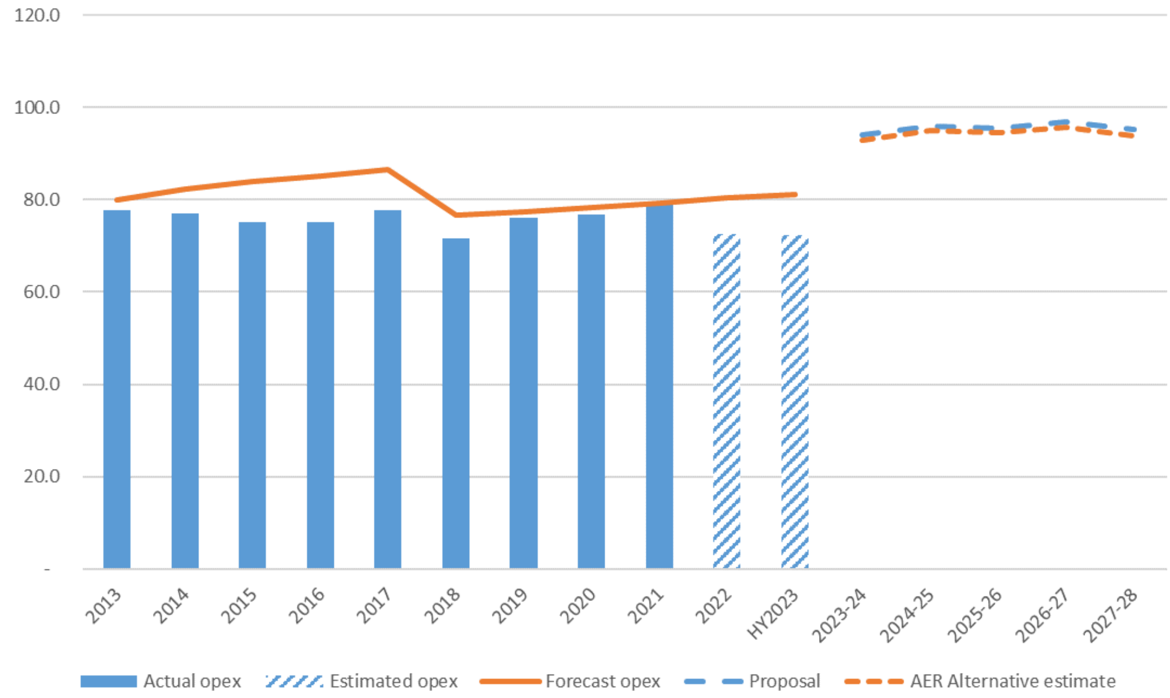
	AGN's updated proposal	AER alternative estimate	Difference
Based (reported opex in 2021)	**387.0**	**398.5**	**11.5**
Base year adjustments	**37.7**	**38.4**	**0.7**
Remove category specific forecasts	**–10.2**	**–10.0**	**0.2**
Final year increment	**16.8**	**8.4**	**–8.4**
Trend: Price growth	5.8	9.3	3.4
Trend: Output growth	4.9	–1.8	–6.7
Trend: Productivity growth	–	1.2	1.2
Total trend	**10.7**	**8.7**	**–2.0**
Capital expenditure to opex	15.9	15.9	–
Cyber security	6.9	–	–6.9
Renewable gas communication and education	3.0	–	–3.0
Total step changes	**25.7**	**15.9**	**–9.9**
Category specific forecasts	**5.0**	**5.1**	**0.1**
Total opex (excluding debt raising costs)	**472.7**	**465.0**	**–7.7**
Debt raising costs	**4.8**	**5.0**	**0.2**
Total opex (including debt raising costs)	**477.5**	**470.0**	**–7.5**
Percentage difference to proposal			**–1.6%**

Source: AER analysis; AGN, *2023–28 Revisions to final plan – Attachment 8.1A – Opex Forecast Model*, September 2022.

Note: Numbers may not add up to total due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

In Figure 6.1 we compare our alternative estimate of opex forecast to AGN's proposal for the next access arrangement period. We also show the forecasts we approved for the last two access arrangement periods from 2013–2022 and AGN's actual and estimated opex across that period.

Figure 6.1 Historical and forecast opex ($million, 2022–23)



Source: AGN, *Regulatory accounts,* 2013 to 2021; AGN, *2023–28 Revisions to final plan – Attachment 8.1A – Opex Forecast Model*, September 2022; AGN, *Access arrangement, PTRM* (multiple periods: 2013–17, 2018–22, 2023–28); AER analysis.

Note: Includes debt raising costs and movements in provisions.

While there is not a material difference between our alternative estimate of total opex and AGN's proposed opex, we have arrived at our alternative estimate in a different way to AGN. The key differences between AGN's opex proposal, which we have accepted, and our alternative estimate are that we have included:

- a more recent inflation forecast from the Reserve Bank of Australia (RBA)[4]
- higher base year opex, which is $11.5 million ($2022–23) more than AGN's proposal, largely because AGN's incorrectly applied inflation when escalating into $2022–23 terms[5], and the removal of non-reference services from base year opex twice[6]
- a final year increment, which is $8.4 million ($2022–23) lower than AGN proposed, primarily due to:
  - updating inflation through to June 2023
  - AGN incorrectly applying inflation when escalating into $2022–23 terms
  - AGN removing debt raising costs from base year opex for the six-months extension period twice[7]

4 RBA, *Statement on Monetary Policy – Appendix: Forecast, November 2022.*

5 AGN, *2023–28 Access arrangement proposal – Information request 24 Q1*, 11 October 2022.

6 AGN, *2023–28 Access arrangement proposal – Information request 21 Q2*, 29 September 2022.

7 AGN, *2023–28 Access arrangement proposal – Information request 24 Q1*, 11 October 2022.

- a higher price growth forecast, which is $3.4 million ($2022–23) more than AGN's forecast primarily due to using a more recent labour price growth forecast and different input price weights
- our exclusion of two step changes proposed by AGN which relate to cyber security ($6.9 million ($2022–23)) and the renewable gas communication and customer education program ($3.0 ($2022–23) million). This is because there is insufficient evidence to justify the additional expenditure as being prudent and efficient, and, in the case of the education program, strong stakeholder opposition.

We note that in our alternative estimate we have included corrections to what in our view are errors in the calculation of some of AGN's forecasts. These largely relate to converting dollars into a $2022–23 basis. While this in some cases has increased forecast opex, we consider this is appropriate as it provides a total opex forecast that would be incurred by a prudent service provider acting efficiently to deliver pipeline services.

Given our draft decision is to accept AGN's total opex forecast, reflecting that our alternative estimate is not materially different from AGN's forecast, we do not require any revisions to be made to AGN's opex proposal for the 2023-28 period. In forming any revised proposal, AGN should consider all of the corrections, amendments and reasoning we have made in forming our alternative estimate.

6.2 AGN's proposal

AGN used a 'base-step-trend' approach to forecast opex for the 2023–28 period, consistent with our preferred approach.[8]

After its initial submission in July 2022, AGN submitted an addendum in September 2022, to reflect changes to estimates following release of the Victorian Government's *Gas Substitution Roadmap.* From an opex perspective this primarily impacted the trend forecasts including AGN's output and productivity growth forecasts.

AGN proposed a total opex forecast of $477.5 million ($2022–23).[9] This included:

- using reported opex in 2021 as the base for forecasting opex over the 2023–28 period (total forecast base opex $387.0 million ($2022–23))
- adjusting its forecast opex by:
  - adding previously capitalised overheads that are proposed to be expensed going forward ($37.7 million, $2022–23)
  - removing unaccounted for gas (UAFG) and debt raising costs ($10.2 million, $2022–23), which it forecast separately as category specific forecasts.
- adding an estimate of the difference between the base year opex and the opex it will in the final year of the current access arrangement period, increasing opex by $16.8 million ($2022–23)

8 AGN, *2023-28 Final plan*, July 2022, p. 74.

9 AER analysis; AGN, *2023–28 Revisions to final plan – Attachment 8.1A – Opex Forecast Model*, September 2022; AGN, *2023–28 Final plan*, July 2022, pp. 69–87; AGN, *2023–28 Revisions to final plan*, September 2022, pp. 18–21.

- applying its overall rate of change forecast to its adjusted base opex, increasing opex by $10.7 million ($2022–23). This included:
  - input price growth increasing opex by $5.8 million ($2022–23)
  - output growth increasing opex by $4.9 million ($2022–23)
  - zero productivity growth
- three step changes for a capex to opex transfer, new cyber security obligations and a renewable gas communication and community education program. This increased its opex forecast by $25.7 million ($2022–23)
- a category specific forecast for a priority service program (PSP) of $5.0 million ($2022–23).
- debt raising costs of $4.8 million ($2022–23).

Table 6.2 AGN's proposed opex for the 2022–23 access arrangement period ($million, 2022–23)

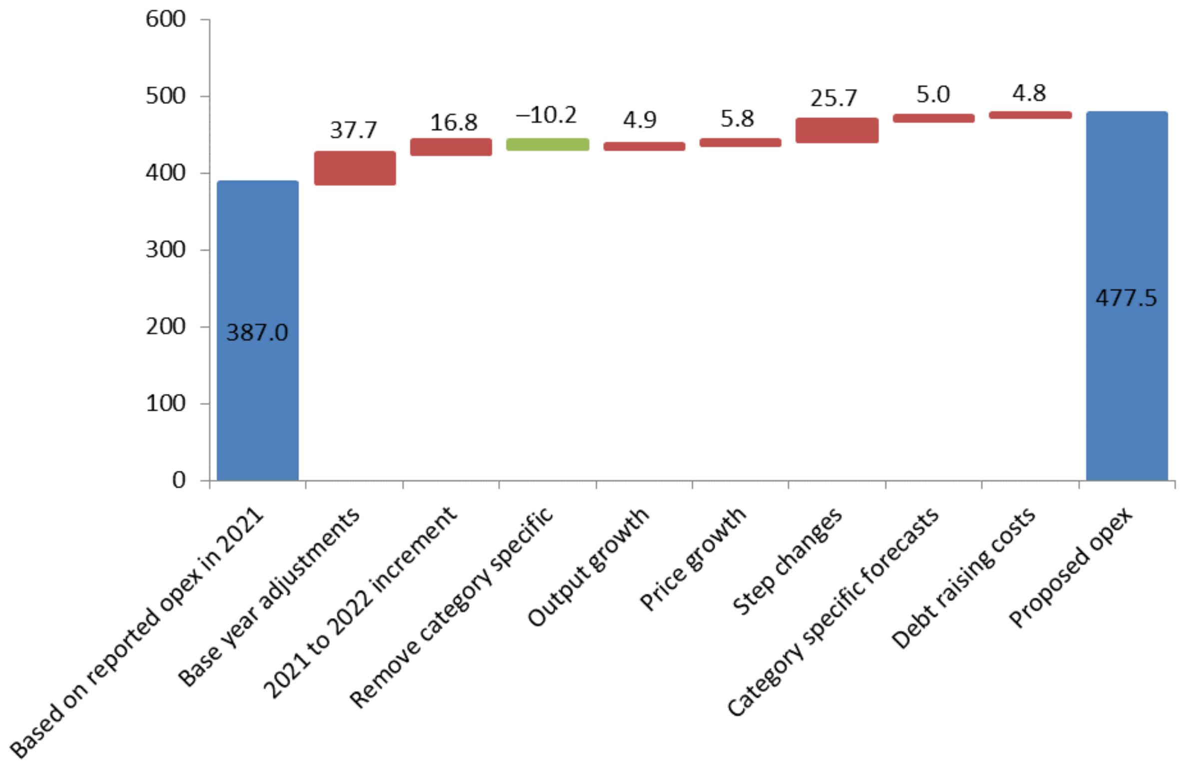
	2023–24	2024–25	2025–26	2026–27	2027–28	Total
Total opex, excluding debt raising costs	93.0	95.0	94.6	96.0	94.2	**472.7**
Debt raising costs	1.0	1.0	1.0	1.0	1.0	**4.8**
Total opex, including debt raising costs	**93.9**	**95.9**	**95.5**	**96.9**	**95.2**	**477.5**

Source: AER analysis; AGN, *2023–28 Revisions to final plan – Attachment 8.1A – Opex Forecast Model*, September 2022.

Note: Numbers may not add up due to rounding.

We show in Figure 6.2 the different elements that make up AGN’s opex forecast for the 2023–28 period.

Figure 6.2 AGN's proposed opex for the 2023–28 access arrangement period ($million, 2022–23)



Source: AGN, *2023–28 Revisions to final plan – Attachment 8.1A – Opex Forecast Model*, September 2022; AER analysis.
Note: Numbers may not add up to total due to rounding.

AGN's total opex forecast of $477.5 million ($2022–23) is $85.4 million ($2022–23), or 21.8%, higher than the amount we determined in our 2018–22 decision for AGN[10] and $100.8 million ($2022–23), or 26.7%, higher than its actual and estimated opex over the 2018–22 access arrangement period.[11]

6.2.1 Stakeholder views

We received submissions raising opex issues from 15 stakeholders, including a joint submission of 8 stakeholders and our Consumer Challenge Panel (CCP28).

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 in relation to opex.

[10] AER, *Australian Gas Networks (Victoria and Albury) access arrangement 2018–22, PTRM – return on debt update for 2022*, October 2021.

[11] AGN, *Regulatory accounts 2018 to 2021*; AGN, *2023–28 Revisions to final plan – Attachment 8.1A – Opex Forecast Model*, September 2022.

Table 6.3 Submissions on AGN's 2023–28 opex proposal

Stakeholder(s)	Issue	Description
Brotherhood of St Laurence (BSL), Joint Victorian Community Organisation (VCO) Submission, BSL (TRAC Partners)	Total opex	BSL's view is that due to stranding risk opex increases should be avoided or minimised. BSL also stated that it views the current AGN gas appliance rebates are not responsible expenditure and should be considered in relation to productivity and discretionary expenditure.[12] BSL does not consider that there is evidence of AGN passing on benefits from its merger (with MGN) to consumers.[13] TRAC Partners, on behalf of BSL, considered the base year choice appropriate.[14] The Joint VCO submission also considered that a high standard of evidence is required for any opex increases.[15] Energy Australia expressed concerns that AGN's proposed opex is much higher than actual expenditure in the current period and considers that it may be comparatively inefficient.[16]
Origin Energy, BSL (TRAC Partners), BSL	Base adjustments	Origin Energy noted the relative ease of migrating costs between capex and opex and considered that cost allocation should be consistent with the cause of the costs and should only change in exceptional circumstances.[17] BSL expressed concerns that AGN expensing previously capitalised overheads will increase tariffs in the near term.[18] TRAC Partners, on behalf of BSL, noted that they did not consider a sound case had been made for expensing overheads.[19]
Energy Users Association of Australia (EUAA), BSL, Origin Energy	Rate of change / trend	The EUAA considered that the *Gas Substitution Roadmap* does not inhibit productivity improvements and that businesses are still incentivised to make productivity improvements.[20] BSL considered that higher productivity targets should be applied, noting that the current offer of rebates indicate that businesses could be more efficient.[21] TRAC Partners, on behalf of BSL, did not consider zero productivity growth appropriate because, even if demand declines, costs are also likely to decrease somewhat, and there is still opportunity for technical change.[22] Origin Energy considered the opex forecast method used, and proposed zero productivity, reasonable considering demand projections.[23]

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12 Brotherhood of St. Laurence, *2023–28 Access arrangement proposal submission*, September 2022, pp. 23–24. Note: Brotherhood of St. Laurence also provided a supporting document prepared on their behalf by TRAC Partners. This supporting document is only cited separately where it provides additional information from BSL's submission.

13 Brotherhood of St. Laurence, *2023–28 Access arrangement proposal submission*, September 2022, p. 26.

14 TRAC Partners prepared on behalf of Brotherhood of St. Laurence, *2023–28 Access arrangement proposal submission*, p. 73.

15 Joint Victorian community organisations, *2023–28 Access arrangement proposal submission*, September 2022, p. 2.

16 Energy Australia, *2023–28 Access arrangement proposal submission*, September 2022, p. 3.

17 Origin Energy, *2023–28 Access arrangement proposal submission*, September 2022, p. 3.

18 Brotherhood of St. Laurence*, 2023–28 Access arrangement proposal submission*, September 2022, p. 26.

19 TRAC Partners prepared on behalf of Brotherhood of St. Laurence, *2023–28 Access arrangement proposal submission*, p. 73.

20 EUAA, *2023–28 Access arrangement proposal submission*, September 2022, p. 9.

21 Brotherhood of St. Laurence*, 2023–28 Access arrangement proposal submission*, September 2022, p. 27.

22 TRAC Partners prepared on behalf of Brotherhood of St. Laurence*2023–28 Access arrangement proposal submission*, September 2022, p. 74.

23 Origin Energy, *2023–28 Access arrangement proposal submission*, September 2022, p. 3.

Stakeholder(s)	Issue	Description
CCP28, EUAA, BSL, Energy Australia, Joint VCO Submission, Friends of the Earth Melbourne, Darebin Climate Action Now	Step changes – renewable gas communication and customer education program	CCP28 expressed concerns about end consumer consultation on the program, noting a need to distinguish between willingness to pay and in-principle/values-based support, and that it appeared the businesses did not explore whether it should be business as usual expenditure, who should pay and who should be responsible for providing the service.[24] The EUAA did not support the program, it noted in-principle support does not indicate willingness to pay and customers should not be incurring these costs.[25] BSL and the Joint VCO submission strongly opposed the proposed program, highlighting the importance of independent information and the absence of an equivalent fund for electrification.[26] Energy Australia, Friends of the Earth Melbourne and Darebin Climate Action Now also opposed the program.[27]
CCP28, EUAA, Energy Australia, BSL, Joint Victorian Community Organisation Submission, Red Energy and Lumo Energy	Category specific forecasts – PSP	CCP28 expressed concerns about consumer consultation on the PSP, noting need to distinguish between willingness to pay and in-principle/values-based support, and that it appears businesses did not explore whether it should be business as usual expenditure, who should pay and who should be responsible for providing the service.[28] The EUAA appreciated the efforts in engagement for the program but questioned if it is a genuine step change, favouring base opex funding given zero productivity.[29] Energy Australia also considered the initiative admirable but thinks that the businesses should fund internally as the expenditure is more discretionary in nature and thus inconsistent with the lowest cost of delivering pipeline services and is concerned the services may be duplicative.[30] BSL and the Joint VCO submission appreciated the initiative but opposed additional consumer funding of the PSP and considered that there is not a demonstrated need for the step change. BSL also noted that some consumers stated their support was dependent on consultation with the community sector.[31] The joint submission also highlighted issues with self-identification for the register and considers that participants in the submission who were also on the PSP advisory panel's views were misrepresented as support.[32] Red and Lumo also did not support additional funding for the PSP. They considered it reflects business as usual activities and offered limited additional value over retailer customer hardship programs. They were also concerned that they have not yet seen any benefits from the AGN (SA) PSP.[33]

24 CCP28, *2023–28 Access arrangement proposal submission*, September 2022, pp.18–20.

25 EUAA, *2023–28 Access arrangement proposal submission*, September 2022, p. 9.

26 Brotherhood of St. Laurence, *2023–28 Access arrangement proposal submission*, September 2022, pp. 24–25; Joint Victorian community organisations, *2023–28 Access arrangement proposal submission*, September 2022, p. 3.

27 Energy Australia, *2023–28 Access arrangement proposal submission,* p. 2; Darebin Climate Action Now (DCAN), *2023–28 Access arrangement proposal submission*, September 2022; Friends of the Earth Melbourne, *2023–28 Access arrangement proposal submission*, p. 2.

28 CCP28, *2023–28 Access arrangement proposal submission*, September 2022, pp.12–13, 18–20.

29 EUAA, *2023–28 Access arrangement proposal submission*, September 2022, p. 9.

30 Energy Australia, *2023–28 Access arrangement proposal submission,* September 2022, p. 3.

31 Brotherhood of St. Laurence, *2023–28 Access arrangement proposal submission*, September 2022, p. 24.

32 Victorian community organisations, *2023–28 Access arrangement proposal submission*, September 2022, pp. 2–3.

33 Red Energy and Lumo Energy, *2023–28 Access arrangement proposal submission*, October 2022, pp. 3–4.

Stakeholder(s)	Issue	Description
CCP28, EUAA, Brotherhood of St Laurence (BSL)	Consumer engagement	CCP28 considered that the engagement was broad, genuine in intent and provided depth on some topics. However, CCP28 had concerns about how topics were raised, adequacy of the level of engagement, the methods used (such as the use of live polls), customer attrition, distinction of in-principle support versus willingness to pay and the absence of engagement with consumers since March 2022, noting economic and policy changes since. It felt that divergent views from stakeholders were insufficiently resolved on some issues, did not consider the supporting stakeholder KPMG report was genuinely independent and viewed the statistics in the customer engagement KPMG report as not a meaningful quantitative measure of consumer support.[34] The EUAA considered the combined network engagement process excellent.[35] BSL felt engagement was well coordinated and supported by useful information, but not all consumer advocate concerns were addressed, and they felt some of their views were misrepresented.[36]

6.3 Assessment approach

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

> Operating expenditure must be as such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.[37]

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

> A forecast or estimate must be arrived at on a reasonable basis and must represent the best forecast or estimate possible in the circumstances.[38]

We use a form of incentive-based regulation to assess the business's forecast opex over the access arrangement period at a total level. To do so, we develop an alternative estimate of total opex using a 'top-down' forecasting method, known as the 'base–step–trend' approach.[39]

Once we have developed our alternative estimate of total opex, we compare it with the business's total opex forecast to form a view on the reasonableness of the business's

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34 CCP28, *2023–28 Access arrangement proposal submission*, September 2022, pp. 14–18.

35 EUAA, *2023–28 Access arrangement proposal submission*, 30 September 2022, p. 3.

36 Brotherhood of St. Laurence, *2023–28 Access arrangement proposal submission*, September 2022, pp. 5, 9–10

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

38 NGR, r. 74(2).

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

proposal. If we are satisfied the business's total forecast meets the NGR requirements, we accept the forecast. If we are not satisfied, we substitute the business's forecast with our alternative estimate.

In making this decision, we consider the reasons for the difference between our alternative estimate and the business's forecast, and the materiality of that difference. We also take into consideration the interrelationships between the opex forecast and other constituent components of our decision, such that our decision is likely to contribute to the achievement of the National Gas Objective (NGO).[40]

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.[41] 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 allowance is granted over a multi-year regulatory period) and the efficiency carryover mechanism (ECM).[42]

The incentive-based regulatory framework partially overcomes the information asymmetries between the regulated businesses and us.[43] 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).[44]

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

The Productivity Commission explains:

> Under incentive regulations, 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

40 NGL, s. 28(1)(a); NGL, s. 23.

41 Productivity Commission, *Electricity Network Regulatory Frameworks, volume 1, No. 62*, 9 April 2013, p. 188.

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

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

44 The NGO is set out under the NGL, s. 23 which is: '...to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.'

> 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.[45]

Incentive regulation is designed to leave the day-to-day decisions to the network businesses.[46] It allows the network businesses the flexibility to manage their assets and labour as they see fit to comply with the opex criteria[47] and achieve the NGO.[48]

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 all individual opex projects or programs. As noted above, to do so, we develop an alternative estimate of total opex using the 'base–step–trend' forecasting approach (section 6.3.2)**Error! Reference source not found.**. This is generally a 'top-down' approach, but there may be circumstances where we need to use 'bottom-up' analysis, particularly in relation to our base opex assessment and for step changes.

6.3.2 Building an alternative estimate of total forecast opex

As a comparison tool to assess a business's opex forecast, we develop an alternative estimate of the business's total opex requirements in the forecast period, using the base–step–trend forecasting approach. We apply the forecasts and estimate requirements under the NGR.[49]

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

Figure 6.3 summarises the base-step-trend forecasting approach:

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

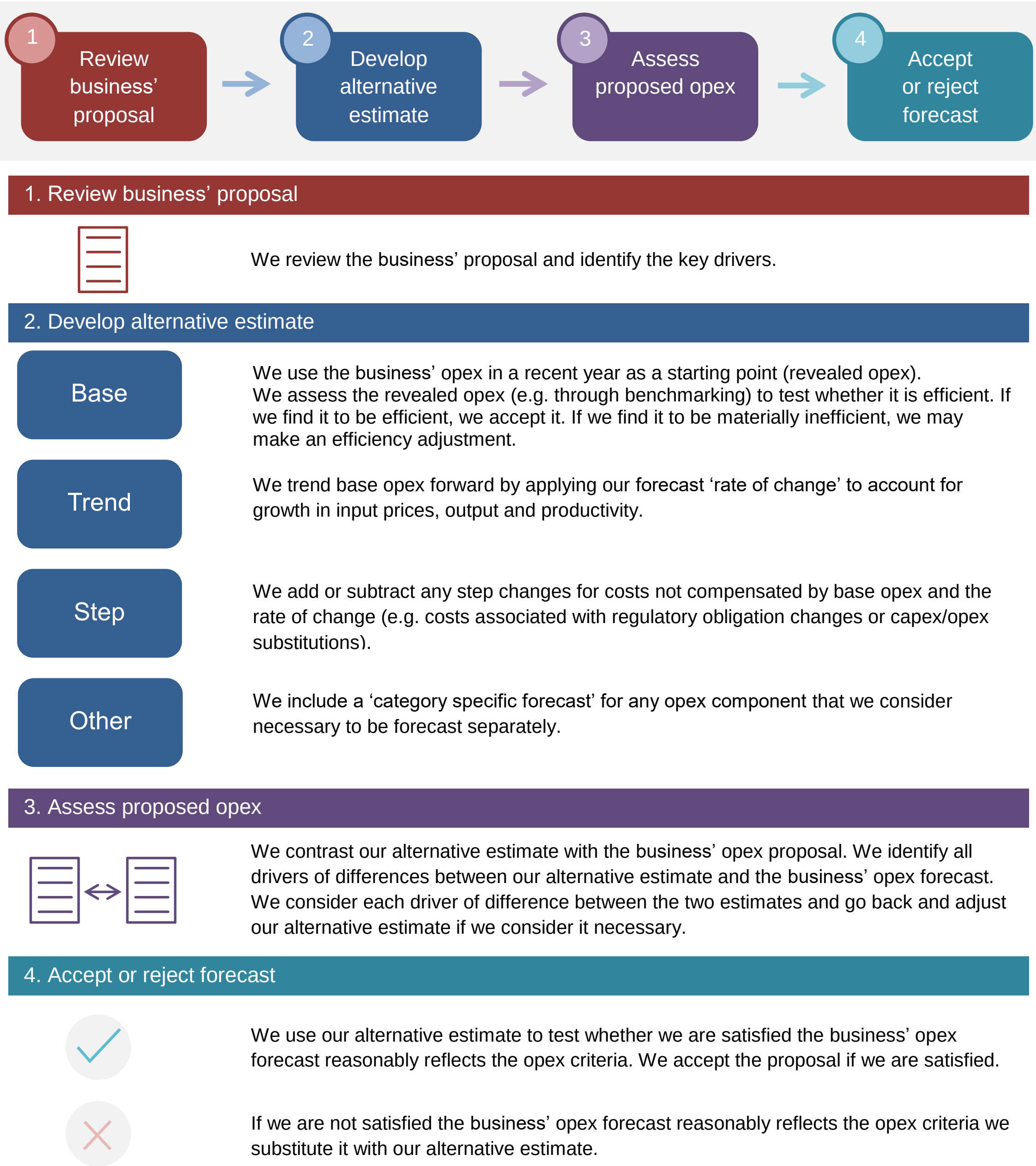
46 Productivity Commission, *Electricity Network Regulatory Frameworks, volume 1, No. 62*, 9 April 2013, pp. 27–28.

47 NGR, r. 91.

48 NGL, ss. 28(1)(a), 23.

49 NGR, r. 74.

Figure 6.3 Our opex assessment approach



6.3.3 Interrelationships

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

- the ECM carryover—the level of opex used as the starting point to forecast opex (the final year of the current access arrangement period, 2018–22) should be the same as the level of opex used to calculate ECM carryovers. This ensures that the business is rewarded (or penalised) for any efficiency gains (or losses) it makes in the final year the same as it would for gains or losses made in other years
- the operation of the ECM in the 2018–22 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 engagement with consumers and stakeholders in developing its regulatory proposal.

6.4 Reasons for draft decision

Our draft decision is to accept AGN's total opex forecast of $477.5 million ($2022–23), including debt raising costs, for the 2023–28 period.[50]

As detailed in Table 6.1, our alternative estimate of $470.0 million ($2022–23) is not materially different ($7.5 million, $2022–23, or 1.6% lower) from AGN's total opex forecast proposal. Therefore, we are satisfied that AGN's total opex forecast satisfies the opex criteria.[51] We are satisfied it was arrived at on a reasonable basis and represents the best forecast possible in the circumstances.[52]

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

6.4.1 Base opex

This section provides our view on the prudent and efficient level of base opex that we consider AGN would need for the safe and reliable provision of services over the 2023–28 access arrangement period.

In its updated proposal, AGN used a base year of 2021 and base year opex of $77.4 million ($2022–23) or $387.0 million ($2022–23) over the five years of the next access arrangement period.[53]

In our alternative estimate, we also used 2021 as the base year but used a base year opex of $79.7 million ($2022–23) or $398.5 million ($2022–23) over 5 years to form our alternative estimate. Our higher alternative estimate is largely due to correcting an error in AGN's proposal related to applying inflation to convert amounts into a $2022–23 basis.[54]

AGN's opex in the first three years of the access arrangement period was slightly lower than allowed in our last determination and slightly higher in 2021. In particular, AGN's opex in 2021 was $0.4 million ($2022–23) or 0.4% higher than the forecast opex we approved in our

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50 AGN, *2023–28 Revisions to final plan – Attachment 8.1A – Opex Forecast Model*, September 2022.

51 NGR, r. 91.

52 NGR, r. 74.

53 AGN, *2023–28 Revisions to final plan – Attachment 8.1A – Opex Forecast Model*, September 2022.

54 AGN, *2023–28 Access arrangement proposal – Information request 24 Q1*, 11 October 2022.

last determination.[55] Opex in 2021 was also $4.9 million ($2022–23) or 6.5% higher than the opex for previous three years of the current period (2018–2020). AGN explained that the main causes of lower-than-expected opex relative to our last determination were reductions in internal costs due to lower network operational costs and lower leak repair and maintenance costs. These savings have been partly offset by higher safety levies.[56]

We do not undertake our own economic benchmarking or category analysis review of gas distributors to assess the efficiency of base year opex. Instead, we rely on the economic benchmarking undertaken by the gas network businesses.

AGN's proposal referred to gas distribution benchmarking analysis (from the AGN (SA) revenue determination process) to support its view that its base year was efficient.[57] This was undertaken in 2020 by Economic Insights and AGN noted that it is the most recent industry benchmarking available. Under one method, the analysis indicated that AGN Victoria and Albury's actual opex per customer was relatively low, but normalised opex was higher for AGN Victoria and low for AGN Albury, compared to the other gas distribution businesses over the 2015–19 period.[58] However, the results from the benchmarking which assessed the opex per customer via another approach produced slightly different results finding both AGN Victoria and Albury's actual opex below average, but AGN Victoria to have below average and AGN Albury above average opex per customer.[59]

While not referred to in AGN's initial proposal, Economic Insights also undertook opex multilateral partial factor productivity benchmarking for AGN (SA) in 2020, including other gas distribution businesses. This showed that AGN was one of the most efficient businesses in terms of opex multilateral partial factor productivity benchmarking over the 1999–2019 period.[60]

Our assessment of the efficiency of opex in the base year has been informed by the benchmarking studies undertaken by Economic Insights in 2020. While this does not include updated data for 2020 or 2021, we consider that the results are indicative of the broader performance of AGN, including in the proposed base year. The results from the benchmarking generally suggest AGN's opex has been relatively efficient. When taken together with AGN's opex being subject to the incentives of the ECM over the 2018–22 period the results suggests that AGN's base opex is likely to be efficient. Typically, where a service provider is subject to an ECM, we are satisfied that there is a continuous incentive for a service provider to make efficiency gains and it does not have an incentive to increase its

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55 AER, *Australian Gas Networks (Victoria and Albury) access arrangement 2018–22, PTRM – return on debt update for 2022*, October 2021.

56 AGN, *2023–28 Access arrangement proposal – Information request 3, Q2*, 12 August 2022; AGN, *2023–28 Access arrangement proposal – Information request 14, Q1*, 12 August 2022.

57 AGN, *2023–28 Final plan*, July 2022, p. 77.

58 AGN, *2023–28 Final plan*, July 2022, p. 77; Economic Insights, *Benchmarking Operating and Capital Costs of Australian Gas Networks' South Australian Network Using Partial Productivity Indicators, report prepared for Australian Gas Networks*, 15 June 2020, pp.22–23.

59 AGN, *2023–28 Final plan*, July 2022, p.77; Economic Insights, *Benchmarking Operating and Capital Costs of Australian Gas Networks' South Australian Network Using Partial Productivity Indicators, report prepared for Australian Gas Networks*, 15 June 2020, pp. 22–23.

60 Economic Insights, *The Productivity Performance of Australian Gas Networks' South Australian Gas Distribution System, report prepared for Australian Gas Networks (AGN),* 15 June 2020, p. 26.

opex above efficient levels in the proposed base year.[61] In terms of Energy Australia's submission that proposed opex is much higher than actual expenditure in the current period, and it may be comparatively inefficient,[62] we do not see this from our analysis. As noted above, actual opex in the first three years of the access arrangement period has been slightly below the forecast opex and marginally higher in the base year. Further, the benchmarking analysis presented suggests AGN's opex has been relatively efficient and the operation of the ECM ensures there are incentives in place for this to occur.

6.4.1.1 Adjustments to base year opex

AGN proposed an increase in base opex of $7.5 million ($2022–23), or a total adjustment of $37.7 million over the five year access arrangement period, to reflect the change in AGN's proposed capitalisation policy change and increased expensing of overheads.[63] In our alternative estimate we have adjusted base year opex by $7.7 million ($2022–23) (or $38.4 million ($2022–23) over five years) to reflect the change in AGN's proposed capitalisation policy, which we consider to be reasonable. The difference between our total adjustment and that of AGN is due to the difference in actual and forecast inflation applied.

AGN proposed to change how it classifies some overheads from capex to opex, in line with changes to its capitalisation policy.[64] In doing this, AGN stated that it will adopt the same approach to classifying and allocating these costs as MGN to align the cost allocation methodology (CAM) between the two businesses.[65] This was in light of AGIG's acquisition of MGN in 2017. AGN submitted that the proposed treatment of overheads for the 2023–28 period would ensure alignment with current accounting standards, including to recognise that the nature of overheads has changed in recent years.[66]

Some stakeholders (Origin Energy and Brotherhood of St. Laurence) did not agree with the proposed expensing of overhead costs in their submissions. Origin Energy requested a more principled and consistent approach to cost allocation[67] and the Brotherhood of St. Laurence argued expensing overheads and other large capex items will increase tariffs in the near term and is not in the best interest of consumers in the current environment.[68]

We have reviewed AGN's proposed adjustment to base opex related to increased expensing of overheads, including the supporting information provided to justify these movements, and we are satisfied that it is reasonable.[69] The expensed overheads are consistent with the new

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

[62] Energy Australia, *2023–28 Access arrangement proposal submission*, September 2022, p. 3.

[63] AGN, *2023–28 Revisions to final plan,* September 2022, p. 19.

[64] AGN, *2023–28 Final plan,* July 2022, p. 75; AGN, *2023–28 Access arrangement proposal – Information request 21 Q3,* 13 September, p. 3.

[65] AGN, *2023–28 Final plan – BDO reclassification of certain programs to opex,* July 2022, pp. 11–12.

[66] AGN, *2023–28 Access arrangement proposal - Information request 21 Q3,* 29 September 2022, p. 4.

[67] Origin Energy, *2023–28 Access arrangement proposal submission,* September 2022, p. 3.

[68] Brotherhood of St. Laurence, *2023–28 Access arrangement proposal submission,* September 2022, p. 26.

[69] AGN, *2023–28 Final plan – BDO reclassification of certain programs to opex*, July 2022, pp. 11–12; AGN, *2023–28 Access arrangement proposal – Information request 21 Q3-4,* 29 September 2022; AGN, *2023–28 Access arrangement proposal – Information request 12 Q1–2,* 13 September 2022.

CAM, can be seen as opex in nature, and AGN has made the required offsetting changes to its capex forecast, which does not include any of the same overhead costs capitalised.

Under the National Electricity Rules (NER), network services providers must submit their proposed CAM to us for approval, and we must approve a proposed CAM that complies with the Cost Allocation Guidelines.[70] By contrast, the NGR do not contain a formal cost allocation framework for gas networks and do not require us to assess a change in AGN's cost allocation or capitalisation policy. In this case, AGN provided a copy of its current CAM along with justification for its proposed changes and we are satisfied that the reclassification is reasonable.[71]

6.4.1.2 Removal of category specific costs

In some circumstances a particular category of opex may be removed from the base year expenditure if it is more appropriate to forecast that category separately. We refer to these as 'category specific forecasts' (see section 6.4.4). We have removed unaccounted for gas (UAFG) and debt raising costs from base opex and forecast them separately. This is consistent with our standard approach and AGN's proposal.[72]

AGN removed $10.2 million ($2022–23) from base opex to account for category specific forecasts, which is $0.2 million ($2022–23) more than the $10.0 million ($2022–23) reduction we made in our alternative estimate.[73] The slight difference between AGN's proposed amount and our alternative estimate is due to our use of the more recent inflation figures when we escalated into $2022–23 terms.

6.4.1.3 Final year increment

Our standard approach to estimating final year opex is to add the difference between the approved forecast opex amounts in the base year (2021) and the final year of the current period to the reported opex in the base year.[74] To account for the six-month extension of the current access arrangement period, we have treated the six-month extension period (1 January–1 July 2023) as the final 'year'. We have annualised forecast opex for the extension period to account for its shorter length. This approach is consistent with AGN's proposal and our past decisions for the Victorian electricity distribution networks.

AGN proposed to include $16.8 million ($2022–23) for the estimate of 1 January–1 July 2023 opex, which is higher than the $8.4 million ($2022–23) in our alternative estimate.[75]

The variance between our alternative estimate and AGN's proposal is due to:

- our use of the latest inflation figures when we escalated base year opex into $2022–23

70 NER, cl. 6.15.2.

71 AGN, *2023–28 Access arrangement proposal – Information request 21*, 29 September 2022.

72 AGN, *2023–28 Final plan,* July 2022, p. 75.

73 AGN, *2023–28 Revisions to final plan – Attachment 8.1A – Opex Forecast Model,* September 2022.

74 AER, *Expenditure forecast assessment guideline for electricity distribution,* November 2022, pp. 24–25.

75 AGN, *2023–28 Revisions to final plan – Attachment 8.1A – Opex Forecast Model,* September 2022.

- correction of an error AGN made in its proposal when escalating its base opex for the six-month extension period, which applied a full year's inflation instead of only six months' worth of inflation
- correction of an error AGN made in its proposal which removed debt raising costs from base opex for the six-month extension period twice.

6.4.2 Rate of change

Once we estimate opex in the final year of the 2018–23 period, we apply a forecast annual rate of change to forecast opex for the 2023–28 access arrangement period. We applied an overall annual average rate of change of 0.3% to derive our alternative estimate of opex. This is lower than AGN's forecast of 0.5%. We compare both forecasts in Table 6.4.

Table 6.4 Forecast annual rate of change in opex (%)

	2023–24	2024–25	2025–26	2026–27	2027–28
AGN's proposal					
Price growth	0.4	0.5	0.6	0.3	0.3
Output growth	0.8	0.6	0.2	–0.3	–0.8
Productivity growth	–	–	–	–	–
Rate of change	**1.1**	**1.1**	**0.8**	**0.0**	**–0.6**
AER alternative estimate					
Price growth	0.6	0.9	0.9	0.4	0.3
Output growth	0.5	0.1	–0.4	–1.1	–1.7
Productivity growth	0.1	–0.0	–0.2	–0.4	–0.6
Rate of change	**1.0**	**1.1**	**0.7**	**–0.3**	**–0.8**
Difference	**–0.2**	**–0.1**	**–0.2**	**–0.3**	**–0.2**

Source: AGN, *2023–28 Revisions to final plan – Attachment 8.1A – Opex Forecast Model*, 2 September 2022
Note: The rate of change = (1 + price growth) × (1 + output growth) × (1 − productivity growth) − 1. Numbers may not add up to totals due to rounding. Amounts of '0.0' and '–0.0' represent small non-zero values and '–' represents zero.

The differences between our forecast rate of change and AGN's are that:

- we have used more recent wage price index (WPI) forecasts to forecast labour price growth
- we have used the input price weights used by ACIL Allen in its 2022 report
- we have used the output weights derived by ACIL Allen in its 2022 report to forecast output growth
- we have used the opex partial productivity forecasts derived by ACIL Allen in its 2022 report, updated to reflect AGN's updated output growth, to forecast productivity growth.

We discuss each of these issues below.

6.4.2.1 Forecast price growth

AGN proposed average annual price growth of 0.4%, which increased its total opex forecast by $5.8 million ($2022–23). We have used real average annual price growth of 0.6% in our alternative estimate of total opex. This increases our total opex alternative estimate by $9.3 million ($2022–23).

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

- Both we and AGN used an average of two wage price index (WPI) growth forecasts for the electricity, gas, water and waste services (utilities) industry in Victoria to forecast labour price growth. AGN used forecasts from its consultant, BIS Oxford Economics, and Deloitte Access Economics.[76] It sourced the Deloitte Access Economics forecasts from our final decisions for the Victorian electricity distributors for the 2021–26 regulatory control period. In our alternative estimate, we have replaced the Deloitte Access Economics forecasts with the more recent forecasts from our new consultant KPMG.[77]
- Both we and AGN applied a forecast non-labour real price growth rate of zero.
- We applied the weights of 62% and 38% to account for the proportion of opex that is labour and non-labour respectively. AGN used weights of 59.7% and 40.3%.

Consequently, the key difference between our real price growth forecasts, and AGN's, is that we have updated our labour price growth forecast to include the more recent forecasts from KPMG, instead of the older Deloitte Access Economics forecasts. We also used different input price weights but the impact of this is less significant.

We have updated our forecasts of WPI to reflect the latest available information

Our standard approach to forecasting labour price growth is to use an average of two WPI growth forecasts for the utilities industry in the relevant state. We use one set of forecasts provided by the network, and one set that we receive from our own consultant. For this determination we engaged KPMG to provide WPI growth forecasts for the Victorian utilities industry.

Consistent with this approach, AGN used forecasts from its consultant, BIS Oxford Economics, and Deloitte Access Economics. It sourced the Deloitte Access Economics forecasts from our final decisions for the Victorian electricity distributors for the 2021–26 regulatory control period.

Since AGN submitted its access arrangement proposal, we have received new WPI growth forecasts from KPMG, which reflect more up-to-date economic information. We used these newer forecasts in place of the Deloitte Access Economics forecasts that AGN used.

We show the labour price growth forecasts from BIS Oxford Economics, KPMG and the average WPI growth rate in Table 6.5. We then added the legislated superannuation guarantee increases to forecast labour price growth. The last legislated superannuation guarantee increase is due to occur on 1 July 2025.[78] We do this because the WPI does not

76 BIS Oxford Economics, *Input price escalation forecasts to 2027/28*, p. 4.

77 KPMG, *WPI forecast report*, September 2022, p. 41.

78 Australian Taxation Office, *Super guarantee percentage, Table 21 - Super guarantee percentage*, accessed 4 November 2022, Accessible at: https://ato.gov.au/SuperRate.

include superannuation and thus the WPI growth forecasts do not capture the increase in the price of labour when the superannuation guarantee increases.

Table 6.5 Forecast labour price growth, %

	2023–24	2024–25	2025–26	2026–27	2027–28
WPI growth — KPMG	0.6	1.1	0.8	0.4	0.4
WPI growth — BIS Oxford Economics	0.4	0.9	1.0	0.9	0.7
Average WPI growth	0.5	1.0	0.9	0.6	0.5
Superannuation guarantee increase	0.5	0.5	0.5	–	–
Forecast labour price growth	1.0	1.5	1.4	0.6	0.5

Source: BIS Oxford Economics, *Input price escalation forecasts to 2027/28*, p. 4; KPMG, *WPI forecast report*, September 2022, p. 41; AER analysis.

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

Input price weights

We have used input price weights of 62% and 38% respectively for labour and non-labour. These are the weights ACIL Allen used in its econometric analysis of output and productivity growth.[79] We understand that these weights have been used consistently in the econometric analysis of gas distribution that both ACIL Allen and Economic Insights have done, and which have been submitted to the AER previously. It is important that the same input price weights are used to forecast price growth as are used in the econometric modelling for output and productivity growth. This ensures both inputs and output are consistently defined to forecast price growth, output growth and productivity growth.

AGN, however, applied input price weights of 59.7% and 40.3% for labour and non-labour respectively to forecast price growth.[80] It stated that the weights it used were based on 'the AER's benchmark weights'.[81] However, these are the input price weights we use for electricity distribution. We use different weights for electricity transmission. We do not have 'benchmark weights' for gas distribution because we don't do benchmarking of gas distributors and we do not publish an annual benchmarking report for gas. As a result, we have used the weights in the ACIL Allen 2022 report.

6.4.2.2 Forecast output growth

AGN proposed average annual output growth rate of 0.1% which increased its proposed opex forecast by $4.9 million ($2022–23). We have forecast average annual output growth of –0.5%. This reduces our alternative estimate of total opex by $1.8 million ($2022–23).

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

79 ACIL Allen, *Opex partial productivity study 2022*, June 2022, p. 11.

80 AGN, *2023–28 Final plan*, July 2022, p. 79.

81 AGN, *2023–28 Final plan*, July 2022, p. 80.

To assess AGN's output and productivity growth forecasts, we tested how the proposed output growth, net of productivity growth, compared to the output and productivity growth forecast using the output specifications derived from the available econometric studies. These econometric studies have been submitted in previous gas distribution determinations and were undertaken between 2015 and 2022.[82] We have taken the opex cost function estimated by each of these studies and forecast output and productivity growth using the forecast growth in energy throughput, customer numbers, mains length and the regulated asset base. In this way we have produced output and productivity growth forecasts specific to AGN's circumstances. When we compared the results of the different studies, we compared forecast output growth and productivity growth together because an output specification that leads to higher output growth often tends to also give higher forecast productivity growth.

When we compared AGN's average annual output growth net of productivity growth of 0.1% against the forecasts based on each of the available econometric studies, we found it to be higher than all of them, as shown in Table 6.6. Consequently, we are not satisfied that AGN's forecast of output growth, net of productivity growth, has been arrived at on a reasonable basis and is the best forecast possible in the circumstances.[83]

Table 6.6 Comparison of forecast output growth net of productivity growth, %

Model Specification	Output growth	Productivity growth	Output growth net of productivity growth
AGN's initial forecast	1.5	0.4	1.0
AGN's updated forecast	**0.1**	**–**	**0.1**
ACIL Allen (2016)	–0.8	–0.6	–0.2
Economic Insights (2015)	–2.5	–1.7	–0.9
ACIL Allen (2016)	–0.8	–0.6	–0.2
Economic Insights (2016)	0.4	0.8	–0.4
Economic Insights (2019)	0.1	1.0	–0.9
ACIL Allen (2022)	**–0.5**	**–0.2**	**–0.3**

Source: AGN, *2023–28 Final plan – Attachment 8.1 – Opex Forecast Model*, July 2022; AGN, *2023–28 Revisions to final plan – Attachment 8.1A – Opex Forecast Model*, September 2022; AER analysis.
Note: Amounts of '0.0' and '–0.0' represent small non-zero values and '–' represents zero.

AGN's forecast is greater than the forecast using ACIL Allen's specification because:

- ACIL Allen modelled two output specifications. One with customer numbers and mains length as the outputs. The other with customer numbers and energy throughput as the

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

83 NGR, r. 74(2).

outputs. AGN only used the output specification that used customer numbers and mains length[84]

- AGN did not use the output weights estimated by ACIL Allen. Instead, it used weights it said were 'consistent with the AER benchmark rates'[85]
- AGN did not use the productivity growth estimated by ACIL Allen in its 2022 report.[86]

We discuss each of these differences below.

ACIL Allen's model specification is the best available in the circumstances

We have considered the econometric modelling of gas distribution networks undertaken in the past and previously submitted to the AER. We are satisfied that the model specifications in ACIL Allen's 2022 report are a reasonable basis to forecast output and productivity growth and represent the best forecast possible in the circumstances.

We also considered the older studies but recognised that they were completed up to seven years ago and have not been updated for data published since. While the results of these studies appear more reasonable when applied to AGN, they are producing results which appear unlikely for MGN. For MGN, these studies are forecasting positive output growth net of productivity growth despite forecasting negative output growth. This is due to greater forecast negative productivity growth than output growth. We consider the outlook facing AGN is more likely to result in lower opex growth, not higher opex growth. These counterintuitive results may reflect that they were undertaken and based on data from an increasing output environment. Given this, we have placed less reliance on these older econometric studies to inform our assessment.

Applying the results of ACIL Allen's 2022 econometric results gives an average annual output growth of –0.5% and annual productivity growth of –0.2%. This gives annual average output growth net of productivity of –0.3%.

Both output specifications should be used

ACIL Allen modelled two output specifications. One with customer numbers and mains length as the outputs and the other with customer numbers and energy throughput as the outputs. We consider both output specifications should be used to forecast output growth.

AGN, however, did not use the output specification that included energy throughput in forming its output growth forecast. We consider that both output specifications should be used to forecast output growth. Both output specifications deliver similar R^2 values (around 0.95) and both mains length and energy throughput achieve similar p values. Further, ACIL Allen undertook a model validation and testing process and concluded that both output specifications should be included in its analysis.[87]

84 AGN, *2023–28 Final plan*, July 2022, p. 79.

85 AGN, *2023–28 Final plan*, July 2022, p. 79.

86 AGN, *2023–28 Final plan*, July 2022, p. 80.

87 ACIL Allen, *Opex partial productivity study 2022*, June 2022, pp. 19–23.

Further, ACIL Allen, in forecasting productivity growth for AGN, followed the advice of Armstrong[88] and combined the forecasts derived from four different sets of econometric results (reflecting two separate output specifications each modelled using two different estimation techniques) to improve forecast accuracy.[89] It did this by using a simple average of the four opex partial productivity forecasts. We agree with ACIL Allen that using an average of multiple modelling results is more likely to produce a more accurate forecast than relying on fewer modelling results. We consider this applies equally to output growth as it does to productivity growth. This also ensures forecast output growth reflects the same output specification as is reflected in the productivity growth forecast. For this reason, we used the average of the four different output forecasts reflecting both output specifications.

Output weights

To forecast output growth, we have relied on the econometric results in ACIL Allen's 2022 report to derive our output weights. AGN did not use the output weights estimated by ACIL Allen. Instead, it used weights it said were consistent with the approach we approved for Jemena's New South Wales gas distribution network and AGN's South Australian gas distribution network.[90] For those decisions we concluded the output weights now proposed by AGN produced forecasts of output growth net of productivity growth that were reasonable when compared to the results of the various econometric studies available at the time. Consequently, those decisions reflected the output growth facing the relevant networks while also considering the proposed productivity growth forecasts. Given all the factors we consider, we may not find a given set of output weights reasonable in all circumstances. This is particularly the case when the weights are not based on econometric results.

For the same reasons we consider both output specifications should be used, we consider the econometric analysis done by ACIL Allen in its 2022 report is a reasonable basis to determine output weights. We also consider those weights represent the best forecast possible in the circumstances. We compare proposed weights to the four sets of weights derived by ACIL Allen in Table 6.7.

Table 6.7. Output weights (%)

	proposed	ACIL Allen Model 1	ACIL Allen Model 2	ACIL Allen Model 3	ACIL Allen Model 4	ACIL Allen Average
Customers	50.6	79.8	96.1	27.0	73.5	**69.1**
Mains length	49.4	–	–	73.0	26.5	**24.9**
Energy throughput	**–**	20.2	3.9	–	–	**6.0**

Source: AGN, *2023–28 Final plan – Attachment 8.1 – Opex Forecast Model*, July 2022.; ACIL Allen, *Opex partial productivity study 2022*, 16 June 2022, pp. 24–25; AER analysis.

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

88 Armstrong, *Principles of forecasting: A Handbook for Researchers and Practitioners*, 2001, pp. 417–439.

89 ACIL Allen, *Opex partial productivity study 2022*, June 2022, p. 46.

90 AGN, *2023–28 Final plan*, July 2022, p. 80.

The impact of using the ACIL Allen's output weights, rather than those proposed by AGN, is to transfer some of weight applied to mains length to customer numbers and some to energy throughput.

6.4.2.3 Forecast productivity growth

AGN proposed average productivity growth of zero. We have forecast a lower average productivity growth of –0.2% per year. This increases our alternative opex estimate by $1.2 million ($2022–23).

AGN reduced its productivity growth forecast from 0.4% in its initial proposal to zero when it updated its proposal to account for the Victorian Government's *Gas Substitution Roadmap*. We agree that the *Gas Substitution Roadmap* is likely to reduce the productivity growth that can be achieved. However, we do not consider AGN arrived at its productivity growth forecast on a reasonable basis.

AGN stated in its updated proposal that:[91]

> … it is appropriate to consider productivity growth attributed to returns to scale and operating environment, as well as productivity growth attributed to technological change. Taking all of these elements into account, we consider a productivity growth forecast of zero over the next AA [Access Arrangement] period is appropriate.

We agree it is appropriate to consider productivity growth attributed to returns to scale and operating environment, as well as productivity growth attributed to technological change. This is why we relied on ACIL Allen's 2022 report and econometric analysis to forecast productivity growth. As outlined above, we consider it is important that forecast productivity reflects the same output specification as used for output growth and is forecast on a consistent basis.

The econometric analysis conducted by ACIL Allen in 2022, and submitted by AGN, found both returns to scale and positive technical change. These results indicate that an efficient gas distributor should achieve positive productivity growth, to the extent that output is forecast to grow. Productivity growth can also be impacted by changes in business conditions. ACIL Allen included the regulatory asset base and customer density as business conditions in its econometric analysis. ACIL Allen included productivity growth forecasts for AGN in its report, but these forecasts reflected the output growth and the change in business conditions forecast prior to AGN amending its proposal to account for the *Gas Substitution Roadmap*. We have updated ACIL Allen's forecasts of opex partial productivity growth to reflect AGN's output growth and business conditions forecasts in its updated proposal.

We note that to forecast productivity growth we have included technical change, returns to scale and changes in business conditions. ACIL Allen only included technical change 'following the standard approach recommended by the AER'.[92] AGN also stated that our standard approach 'has been to calculate the recommended opex productivity growth factor

[91] AGN, *2023–28 Revisions to final plan,* September 2022, p. 20.

[92] ACIL Allen, *Opex partial productivity study 2022*, June 2022, p. 24.

based only on the rate of technical change'.[93] However, this is not our standard approach, and it is unclear why ACIL Allen and AGN considered this to be the case (neither provided a reference to support this position).

Consistent with the ACIL Allen 2022 report, we have included technical change of 0.2% in our productivity growth forecast.

Regarding returns to scale, we note that ACIL stated:[94]

> We would expect there to be economies of scale with regard to opex in the gas distribution business. This is both logical and supported by a significant number of empirical studies of both gas and electricity distribution businesses.

We consider that lower output growth will reduce the expected returns to scale. Given we have forecast negative average output growth we expect the loss of returns to scale to put downward pressure on productivity growth. Based on ACIL Allen's econometric analysis we expect the loss of returns to scale to reduce average annual productivity growth by 0.1%.

We have also considered the impact of the expected change in business conditions on productivity growth. We expect these to reduce average annual productivity growth by 0.3%, largely due to the expected decline in customer density.

The net impact of technical change, the loss of returns to scale, and the change in business conditions, is a forecast average annual opex partial productivity growth of –0.2%. We have used this as our forecast of productivity growth.

Stakeholder submissions

We received several submissions that addressed productivity growth. The EUAA and the Brotherhood of St. Laurence considered the gas distributors should be able to achieve positive productivity growth forecasts.[95] Historically we have expected this for gas distributors, given econometric studies have consistently found positive technical change and positive returns to scale. However, the forecast of productivity growth should reflect the outlook facing the network, particularly forecast output growth and the forecast change in business conditions. In this case, having considered these factors, we have forecast productivity growth of –0.2%.

Origin Energy, however, considered zero productivity growth to be 'a reasonable approach given the networks are no longer expected to grow'.[96] Origin Energy's submission recognised that fewer returns to scale can be expected in a low growth environment. We have taken this into account and our forecast of productivity growth reflects expected output growth as well as the expected change in business conditions.

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93 AGN, *2023–28 Revisions to final plan,* September 2022, p. 20.

94 ACIL Allen, *Opex partial productivity study 2022*, June 2022, p. 20.

95 EUAA, *2023–28 Access arrangement proposal submission*, September 2022, p. 9; Brotherhood of St. Laurence, *2023–28 Access arrangement proposal submission*, September 2022, p. 27.

96 Origin Energy, *2023–28 Access arrangement proposal submission*, September 2022, p. 3.

6.4.3 Step changes

In developing our alternative estimate, we include prudent and efficient step changes for cost drivers such as new regulatory obligations or efficient capex / opex trade-offs. As we explain in the *Expenditure forecast assessment* guideline for electricity, we will generally include a step change if the efficient base opex and the rate of change in opex of an efficient service provider do not already include the proposed cost for such items and they are required to meet the opex criteria.[97]

AGN's proposal include three step changes totalling $25.7 million ($2022–23), or 5.4% of its proposed total opex forecast.[98] We show these in Table 6.8 along with our alternative estimate, which is to include step changes totalling $15.9 million ($2022–23). Our lower alternative estimate reflects that we are not satisfied that all the proposed step changes are prudent and efficient.

Table 6.8 AGN proposal for step changes and our alternative estimate ($million, 2022–23)

Step change	AGN's proposal	AER alternative estimate	Difference
Capex to opex reclassification	15.9	15.9	–
Cyber security	6.9	–	–6.9
Renewable gas communication and customer education program	3.0	–	–3.0
Total	**25.7**	**15.9**	**–9.9**

Source: AER analysis; AGN, *2023–28 Revisions to final plan – Attachment 8.1A – Opex Forecast Model*, September 2022.

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

The following sections outline the reasons for our draft decision, including the alternative estimates we have developed.

6.4.3.1 Capex-opex reclassification of activities

AGN initially proposed a $16.3 ($2022–23) million step change for the reclassification of certain activities, previously classified as capex, to opex.[99] AGN subsequently revised this number to $15.9 million ($2022–23) when it submitted its updated initial proposal.[100] This included correcting an error we identified in the application of the CPI in the capex model. We have included $15.9 million ($2022–23) in our alternative estimate for the proposed step change because we consider these costs are prudent and efficient.

97 AER, *Expenditure forecast assessment guideline for electricity distribution,* August 2022, p. 26.

98 AGN, *2023–28 Final Plan*, July 2022, pp. 77–78; AGN, *2023–28 Revisions to final plan,* September 2022, p. 19.

99 AGN, *2023–28 Final Plan,* July 2022, p. 78.

100 AGN, *2023–28 Revisions to final plan,* September 2022, p. 19.

Table 6.9 AGN's capex-opex reclassification step change ($million, 2022–23)

	2023–24	2024–25	2025–26	2026–27	2027–28	Total
AGN's updated proposal	2.6	3.9	2.7	4.0	2.7	15.9
AER alternative estimate	2.6	3.9	2.7	4.0	2.7	15.9
Difference		–	–	–	–	–

Source: AGN, *2023–28 Revisions to final plan – Attachment 8.1A – Opex Forecast Model*, September 2022; AER analysis

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

AGN proposed that certain activities previously classified as capex, were more consistent with an opex classification. As a result, it proposed a step change which increases its forecast opex by $15.9 million ($2022–23). It provided a report from accounting firm BDO to confirm that these costs met the accounting standards and relevant criteria for opex classification.[101] AGN also provided detailed business cases for each program of costs to be expensed in the 2023–28 period, describing the need for the activity and including the options analysis it had undertaken with a cost breakdown for each option.

We have reviewed AGN's proposed reclassification of activities and we are satisfied that it is reasonable, and the costs are prudent and efficient. The activities proposed for reclassification (such as sampling or repair and maintenance type activities), are driven by safety and compliance obligations, occur every access arrangement period and do not extend the life of the assets. We are also satisfied that no project costs have been counted in both capex and opex, and that all costs moved to opex have been removed from forecast capex.

6.4.3.2 Cyber Security

AGN proposed a step change of $6.9 million ($2022–23) to meet new legislative obligations under the *Security Legislation Amendment (Critical Infrastructure Protection) Act 2022*.[102] AGN considered it would need to achieve maturity indicator level 3 (MIL-3), security profile 3 (SP3), capabilities as set out in the Australian energy sector cyber security framework (AESCSF) to meet these obligations. We have not included the proposed step change in our alternative estimate. We consider that AGN's proposal to achieve MIL-3, SP 3, capabilities is higher than the prudent and efficient investment required to meet the likely regulatory obligations of complying with security profile 1 (SP1) capabilities under *Security Legislation Amendment (Critical Infrastructure Protection) Act 2022.*

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[101] AGN, *2023–28 Final plan – Attachment 8.3 – BDO reclassification of certain programs to opex,* July 2022.

[102] AGN, *2023–28 Final Plan – Attachment 9.14 – IT Business Cases,* July 2021. p. 73.

Table 6.10 AGN's Cyber Security step change ($million, 2022–23)

	2023–24	2024–25	2025–26	2026–27	2027–28	Total
AGN's proposal	1.3	1.3	1.4	1.4	1.4	6.9
AER alternative estimate	–	–	–	–	–	–
Difference	**–1.3**	**–1.3**	**–1.4**	**–1.4**	**–1.4**	**–6.9**

Source: AGN, *2023–28 Revisions to final plan – Attachment 8.1A – Opex Forecast Model*, September 2022; AER analysis.

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

In terms of the legislative requirements for the security of critical infrastructure, we note that the original *Security of Critical Infrastructure Act 2018* has undergone several amendments. The first being the *Security Legislation Amendment (Critical infrastructure Protection) Bill 2020,* which was divided into two separate parts. The first part became the *Security Legislation Amendment (Critical Infrastructure) Act 2021* in December 2021 and put in place the requirements for entities to report cyber security incidents, and the setting up of a regime for the Commonwealth to respond to serious cyber security incidents.[103] The second part became the *Security Legislation Amendment (Critical Infrastructure Protection) Act 2022* in April 2022, which requires responsible entities to have and comply with a critical infrastructure risk management program (RMP) and also imposes enhanced cyber security obligations that relate to Systems of National Significance.[104]

The regulatory obligation to have a RMP in place, under the *Security Legislation Amendment (Critical Infrastructure Protection) Act 2022,* has not yet been switched on by the relevant minister. This is likely to occur in December 2022. The Australian Government Department of Home Affairs has released draft *Security of Critical Infrastructure (Critical Infrastructure risk management program) Rules 2022,*[105] which specifies the matters it proposed to be contained in an RMP and requires responsible entities to meet principle-based outcomes.

The RMP requires responsible entities to identify, and as far as reasonably practicable, take steps to minimise or eliminate material risks that could have a relevant impact on the asset.[106] At present the proposed *Security of Critical Infrastructure (Critical Infrastructure risk management program) Rules 2022* contain obligations relating to protections within four key hazard vectors, being physical and natural, cyber and information security, personnel and supply chain functions.[107] In regard to the cyber and information security vector, a business's RMP must assess cyber security risks and in this regard the *Security of Critical Infrastructure (Critical Infrastructure risk management program) Rules 2022,* if passed, will require energy providers to meet obligations set out in the 2020–21 AESCSF Framework Core, and

103 Australian Government, Security Legislation Amendment (Critical Infrastructure) Act 2021, December 2021.

104 Australian Government, Security Legislation Amendment (Critical Infrastructure Protection) Act 2022, April 2022. Part 4-6.

105 Australian Government, *Security of Critical Infrastructure (Critical infrastructure risk management program) Rules (LIN 22/018) 2022*, Draft Only, February 2022.

106 Australian Government, *CISC Factsheet – Risk Management Program,* August 2022, p. 1.

107 Australian Government, *CISC Factsheet – Risk Management Program,* August 2022, p. 2.

specifically requiring the entity to meet SP1. These draft rules are currently undergoing consultation with industry and stakeholders.

We asked AGN to identify the specific regulatory obligation in *the Security Legislation Amendment (Critical Infrastructure Protection) Act 2022* or any other legislative requirement which required compliance with MIL-3, SP3. AGN stated that the *Security Legislation Amendment (Critical Infrastructure Protection) Act 2022* requires it (as a responsible entity for certain critical infrastructure assets) to comply with risk management program obligations, once the *Security of Critical Infrastructure (Critical Infrastructure risk management program) Rules 2022* are "turned on" by the relevant minister. AGN expected, based on its current view of the rules, that a maturity level of SP1 will be required within 18 months of the rules being turned on, which will require AGN to achieve MIL-3 compliance in some areas of the AESCSF.[108]

AGN engaged Ernst & Young and with its assistance developed the AGIG Cyber Security 5 Year Roadmap.[109] The program was designed to uplift AGIG's cyber risk management capabilities to MIL-3 standard (as defined in the AESCSF) over the period 2021–25, including for AGN. The 5 Year Roadmap outlined AGN's step change scope of works for its security domain activities to achieve MIL-3 compliance. We consider that for some of these security domains, achieving MIL-3 compliance to be in excess of the requirements to meet the compliance obligations of SP1, as defined in the AESCSF.[110]

Our technical advisory group considered that while the AESCSF requirements are currently not compulsory standards, given the *Security Legislation Amendment (Critical Infrastructure Protection) Act 2022*, the AESCSF requirements should be considered good industry practice. We also understand the risk management plan requirements are likely to be switched on in December 2022.[111] When the risk management requirements are switched on it is likely that AGN as a gas distribution business will be required to comply with the rule requirements to reach the capabilities of a maturity level of SP1 against the AESCSF.

The EUAA supported the concept of a step change for cyber security.[112] It and the Brotherhood of St Laurence commented that it is important that the AER assesses whether the amount is prudent and efficient.[113]

We consider that currently there is no new regulatory obligation for AGN to achieve the capabilities of SP3 of the AESCSF as indicated in its proposal. We also consider that as a result, AGN's proposed expenditure, which is based on MIL-3, SP3 requirements, is higher than the likely efficient expenditure required to meet the regulatory obligations of the RMP when it is switched on (SP1, consistent with the draft rules and the information presented by

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108 AGN, *2023–28 Access arrangement proposal – Information request 20,* 21 September 2022.

109 AGN, *2023–28 Final plan – Attachment 9.14 IT Business Cases,* Public, July 2021. p. 53.

110 Australian Government, *Australian Energy Sector Cyber Security Framework – 2022 AESCSF Framework Core,* 19 April 2022.

111 Australian Government, *Department of Home Affairs – Risk Management Program – Formal Consultation – Town Hall*, October 2022.

112 EUAA, *2023–28 Access arrangement proposal submission*, September 2022, p. 9.

113 TRAC Partners prepared on behalf of Brotherhood of St. Laurence, *2023–28 Access arrangement proposal submission,* September 2022, p. 65.

the Department of Home Affairs consultation on the risk management program). As a result, we have not included this step change in our alternative estimate.

6.4.3.3 Renewable gas communication and customer education program

AGN proposed a $3.0 ($2022–23) million step change for a renewable gas communications and customer education program (the program). We have not included this step change in our alternative estimate.

Table 6.11 AGN's Renewable gas communication and customer education program step change ($million, 2022–23)

	2023–24	2024–25	2025–26	2026–27	2027–28	Total
AGN proposal	0.6	0.6	0.6	0.6	0.6	3.0
AER alternative estimate	–	–	–	–	–	–
Difference to AGN proposal	**–0.6**	**–0.6**	**–0.6**	**–0.6**	**–0.6**	**–3.0**

Source: AGN, *2023–28 Revisions to final plan – Attachment 8.2 – Opex Business Cases*, September 2022; AER analysis

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

AGN originally presented this step change in its draft plan at a cost of $7.4 million ($2022-23).[114] However, in response to stakeholder feedback on the draft plan, AGN stated the $4.4 million ($2022–23) marketing component would be funded through AGN's existing opex (now $4.5 million, $2022–23). The customer funded portion of the program which was included in AGN's proposal consists of $1.2 million ($2022–23) for expanded community engagement and $1.8 million ($2022–23) for school education, proposed due to customer interest expressed during consultation workshops.[115]

The proposed purpose of the program is to increase customer's awareness of AGN's renewable gas plans and provide customers with information to assist with choices they are making now around energy connections and appliances. AGN proposed this step change based on:

- low customer awareness and strong interest in receiving further information on renewable gas and in emissions reduction[116]
- managing reputational and customer risks associated with customer satisfaction and information availability and financial risks associated with reductions in demand and new connections[117]
- customer support for the program based on in-workshop polls where 68% of respondents to an in-workshop poll strongly supported, and 22% somewhat supported, the program[118]

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114 AGN, *2023–28 Final plan – Attachment 1.2 – Draft plan (January 2022)*, July 2022, p. 71.

115 AGN, *2023–28 Final plan – Attachment 8.2 – Opex Business Cases*, July 2022, pp. 38–39

116 AGN, *2023–28 Final plan – Attachment 8.2 – Opex Business Cases*, July 2022, p. 23.

117 AGN, *2023–28 Final plan – Attachment 8.2 – Opex Business Cases*, July 2022, pp. 24–25, 31, 39–40.

118 AGN, *2023–28 Final plan – Attachment 5.3 – KPMG Final Report – AGN Customer Engagement Program,* July 2022, p. 35.

Many stakeholders strongly opposed renewable gas communications from gas distribution businesses and additional funding for the program. Stakeholders were concerned about additional expenditure particularly at a time where there may be network decline, uncertainty as to the viability of hydrogen in networks, and the need for independent information on the future of energy.[119] CCP28, while considering the AGN's engagement to be genuine, raised concerns about what it saw as limitations of the consultation and assessment of customer support, including participant attrition, use of live polls and an apparent absence of discussion about who should pay.[120]

We have reviewed the materials provided by AGN in supporting the proposed communications and education program, including via additional information requests to clarify specific issues, and we have not included this step change in our alternative estimate.

In coming to this decision, we have considered that:

- The program expenditure is not driven by a new regulatory requirement, capex-opex trade off or a necessary response to an external change, but rather a level of customer support for these more discretionary actions.[121] In this regard we recognise the genuine effort and processes undertaken to engage with customers in relation to the program to test their support or otherwise for it, noting that the modest number of diverse, but not representative, customers directly consulted supported or somewhat supported the program at a cost of $2.00 annual cost per customer. However, we also consider that there were aspects of the customer consultation and assessment that could have been improved to inform this assessment.
- Despite the support AGN found when engaging with customers directly, there was strong stakeholder opposition to the step change and the associated additional costs. This remained the case even after AGN responded to the feedback it received in relation to its draft plan proposal and removed the marketing costs from the step change.
- Community engagement can be useful to enable customers to engage directly, but could also be comparable to marketing in this context. This is particularly the case where there is significant uncertainty, possible further policy changes and changing demands. In addition, at $1.2 million ($2022–23) over the 2023–28 access arrangement period, the costs can likely be paid for within business-as-usual expenditure.
- AGN has not in our view provided sufficient evidence that the customer funded community and education components of the step change are an efficient way to meet the objectives of the program (ensuring that customers are informed, involved and engaged in the energy transition as it relates to gas and are provided with the information they need to inform the choices they are making). In particular we consider that insufficient evidence has been provided that shows that school education is an

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119 EUAA, *2023–28 Access arrangement proposal submission*, September 2022, p. 9: Brotherhood of St. Laurence, *2023–28 Access arrangement proposal submission*, September 2022, pp. 24–25; Joint Victorian community organisations, *2023–28 Access arrangement proposal submission*, September 2022, p. 3; Energy Australia, *2023–28 Access arrangement proposal submission*, September 2022, p. 2; Darebin Climate Action Now (DCAN), *2023–28 Access arrangement proposal submission*, September 2022, p. 3; Friends of the Earth Melbourne, *2023–28 Access arrangement proposal submission*, September 2022, p. 2.

120 CCP28, *2023–28 Access arrangement proposal submission*, September 2022 pp. 5, 17–20.

121 AER, *Better Resets Handbook – Towards Consumer Centric Network Proposals*, December 2021, pp. 27–28.

efficient means of meeting the program's objectives of providing customers with awareness and practical information they need now. AGN noted that customers wanted this service and that children can influence their families on sustainability matters and in some product categories. However, it is unclear to us whether it is efficient to use children/students to distribute information to current customers, and whether it is prudent to provide this information to children/students now as future customers, given the current levels of uncertainty, and that choice to use gas is largely limited to homeowners

- In addition, there is currently uncertainty as to the viability of renewable gas in material volumes in the Victorian gas distribution network, the future Victorian government policy around gas substitution and appliance replacement requirements. This uncertainty has been highlighted by AGN as presenting an asset stranding risk and which it proposed to reduce via accelerated depreciation.[122] While the future of gas may become clearer within the access arrangement period, we consider that it may be difficult for AGN to meet the program's objectives of offering customers with certainty and practical information about their energy and appliance choices
- Further, our view is that it remains open to AGN to use its base opex to communicate to customers, including the $4.5 million ($2022–23) in opex funding that AGN noted would be used for marketing purposes, following stakeholder feedback.

6.4.4 Category specific forecasts

AGN's proposal included three expenditure items, or category specific forecasts, which it did not forecast using the base-step-trend approach. These were for debt raising costs, UAFG and the PSP. We have also included category specific forecasts for debt raising costs, UAFG and the PSP in our alternative estimate of total opex.

6.4.4.1 Debt raising costs

AGN proposed a category specific forecast for debt raising costs of $5.0 million in its initial proposal[123] but reduced its forecast to $4.8 million in its updated proposal.[124] We have included debt raising costs of $5.0 million ($2022–23) in our alternative estimate. This is $0.2 million ($2022–23) higher than AGN's updated proposal.

Debt raising costs are transaction costs a service provider incurs each time it raises or refinances debt. Our preferred approach is to forecast debt raising costs based on a benchmarking approach rather than a service provider's actual costs for consistency with the forecast of the cost of debt in the rate of return building block.

We used our standard approach to forecast debt raising costs, which is discussed further in Attachment 3 to the draft decision.

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122 AGN, *2023–28 Final plan*, July 2022, pp. 54–63.

123 AGN, *2023–28 Final plan*, July 2022, p. 82.

124 AGN, *Revisions to final plan 2023–28, Attachment 8.1A – Opex model*, September 2022.

6.4.4.2 Unaccounted for gas

Consistent with AGN's proposal and our past decisions, we have included a category specific forecast of zero dollars in our alternative estimate for any UAFG penalties or rewards AGN receives. Consistent with this, we also propose to exclude UAFG costs from the ECM.

UAFG refers to the difference between the quantity of gas delivered into and out of the distribution system. UAFG may be attributable to gas leakage or inaccurate gas measurement. The Essential Services Commission of Victoria sets a UAFG 'benchmark' within which AGN is expected to operate.[125] To provide an incentive for AGN to minimise gas losses, it incurs a penalty if UAFG exceeds the benchmark and receives a reward if it falls under the benchmark. To preserve this incentive, the business itself should incur the penalty or keep the reward, not consumers. As a result, we include a zero forecast for UAFG in our alternative estimate.

6.4.4.3 Priority service program

AGN proposed $5.0 million ($2022–23) additional funding for a PSP to support customers experiencing vulnerability. The program includes:

- dedicated staff to design, manage and deliver the program
- development of a 'priority services register'
- improved communications for culturally and linguistically diverse customers
- gas safety checks, emergency repairs and outage support.[126]

For the purpose of this draft decision we have included the PSP costs at $5.1 million ($2022-23) as proposed but updated for inflation in our alternative estimate as a category specific forecast. However, we encourage AGN in preparing its revised proposal to continue to work with customers and relevant stakeholders to potentially refine and revise the scope of the program, test customer support and demonstrate an efficient use of resources.

AGN proposed the PSP as a category specific forecast, consistent with the final decision for AGN (SA)'s 2021–26 access arrangement. In AGN (SA)'s final decision we stated that customer supported initiatives, such as the vulnerable customer assistance program (VCAP), should be classified as a category specific forecast instead of a step change. This ensures the funding is spent as intended, requires businesses to report expenditure and allows us to remove the expenditure from the ECM.[127] This is also consistent with the *Better Resets Handbook*, which states that category specific forecasts should be limited to cost categories that have been included as category specific costs in previous AER decisions.[128]

AGN proposed the additional expenditure for this program on the basis:[129]

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125 AGN, *2023–28 Final plan,* July 2022, p. 75.

126 AGN, *2023–28 Revisions to final plan,* September 2022, p.19; AGN, *2023–28 Final plan – Attachment 8.2 – Opex Business Cases*, July 2022, pp. 45–46.

127 AER, *Final decision, Australian Gas Networks (SA) Access Arrangement 2021–26 – Attachment 6 – Operating expenditure,* April 2021, p. 23.

128 AER, *Better Resets Handbook – Towards Consumer Centric Network Proposals*, December 2021, p. 29.

129 AGN, *2023–28 Final plan – Attachment 8.2 – Opex Business Cases*, July 2022, pp. 44–47, 62–64, 74–76.

- that there is a role for networks to support customers experiencing vulnerability, highlighted by the *Energy Charter*, the AER *Draft Consumer Vulnerability Strategy* and associated Consumer Policy Research Centre research and the Financial Services Royal Commission
- of consistency with good industry practice, social license to operate, and the National Gas Objective in that it is in the long-term interest of customers
- that it facilitates risk management – reducing AGN's risks around reputation, customer experience and occupational health and safety from moderate to low
- customer support – 93% of customers that responded to an in-workshop poll and considered dedicated support for vulnerable customers important or very important in the context of a $1.50 annual cost per customer.[130]

Other stakeholders appreciated the initiative but did not support additional funding for the PSP.[131] The Joint VCO submission raised concerns about the use of a register becoming a barrier for participation.[132] TRAC Partners, on behalf of The Brotherhood of St Laurence also raised concerns about the efficiency of network-specific programs given similar programs are also proposed by the other Victorian gas networks.[133] CCP28, while considering AGN's engagement to be genuine, raised concerns about what it saw as limitations in the consultation and assessment of customer support, including participant attrition, use of live polls and apparent absence of discussion about who should pay.[134]

We have reviewed the materials provided by AGN to support its PSP, including information provided in response to additional information requests. For the purpose of the draft decision, we have included the PSP costs as proposed in our alternative estimate. This is an on-balance decision and reflects that while this proposed step up in costs is not driven by a new obligation or capex/opex trade off:

- the PSP is similar to the VCAP program approved for AGN SA, and that we consider that the activities proposed result in a material increase in services, including:[135]
  - a dedicated customer service lead and manager to deliver the program and improve the customer experience for customers experiencing vulnerability
  - a priority services register resulting in a more responsive customer environment

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130 AGN, *2023–28 Access arrangement proposal – Information request 19*, 27 September 2022.

131 EUAA, *2023–28 Access arrangement proposal submission*, September 2022, p. 9: Brotherhood of St. Laurence, *2023–28 Access arrangement proposal submission*, September 2022, p. 26; Victorian community organisations, *2023–28 Access arrangement proposal submission*, September 2022, pp. 2–3; Energy Australia, *2023–28 Access arrangement proposal submission*, September 2022, p. 3; Red Energy and Lumo Energy, *2023–28 Access arrangement proposal submission*, October 2022, pp. 3–4.

132 Victorian community organisations, *2023–28 Access arrangement proposal submission*, September 2022, p. 2.

133 TRAC Partners on behalf of Brotherhood of St. Laurence, *2023–28 Access arrangement proposal submission*, September 2022, p. 49.

134 CCP28, *2023–28 Access arrangement proposal submission*, September 2022, pp. 5, 17–20.

135 AER, Final Decision, *Australian Gas Networks (SA) Access Arrangement, 2021–26 – Attachment 6 Operating expenditure*, April 2021, p. 24; AGN, *2023–28 Final plan – Attachment 8.2 – Opex Business Cases*, July 2022, pp. 76–77.

  - gas safety appliance checks and emergency appliance repairs improving the safety and reliability of vulnerable customers gas appliances and gas use

- we recognise the genuine effort and processes undertaken to engage with customers in relation to the PSP to test their support or otherwise for it, noting:
  - the modest number of diverse, but not representative customers directly consulted were of the view that it was important or very important to support vulnerable customers in the context of a $1.50 annual cost per customer, and
  - the effort to engage relevant stakeholders via the PSP Advisory Panel, which, while not supportive of additional costs, appreciated the initiative.
- AGN's efforts to research and minimise duplication of services, align with other networks for consistency and consult with relevant stakeholders to develop the program, and commitment to ongoing consultation with these groups, as well as government agencies and other parts of the energy supply chain[136]
- in the *Towards Energy Equity* Strategy,[137] we recognised the need to deliver better outcomes for customers experiencing vulnerability and avoid exacerbating harm, which is an objective of this program.[138]

Further, we consider that the proposed costs do not appear to be inefficient, with cost estimates for each activity proposed being provided and reflecting costs for similar activities undertaken elsewhere in AGN's business or externally and/or being based on market-based quotes.

While recognising the genuine effort by AGN to engage and consult, as raised by some stakeholders we acknowledge that the customer and stakeholder consultation and assessment of support could have been improved. This includes more clearly establishing and explaining the degree of need for these programs, and for them to be customer funded, and more widely and robustly testing customer and stakeholder willingness to pay for additional programs and addressing and / or reconciling any differences of view in terms of willingness to pay. We also encourage further consideration of the sample size and representation / mix of customers consulted.

In this regard, we encourage AGN in preparing its revised proposal to continue to work with customers and relevant stakeholders to potentially refine and revise the scope of the program, test customer support and demonstrate an efficient use of resources as reasonable for the scale of the program. This could include reviewing and refining the services proposed, in consideration of stakeholder feedback, particularly concerns around issues with the register being a barrier to participation, which may also benefit from experience and learnings in other sectors such as financial services. We also encourage AGN to consider how the program's costs are best funded, further exploring whether there are efficiencies that can be achieved via collaboration, or review, and addressing other specific stakeholder comments on the program particularly where there are differing views between customers and stakeholders. Also noted by CCP28, this is particularly pertinent given economic and

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136 AGN, *2023–28 Final plan – Attachment 8.2 – Opex Business Cases*, July 2022, pp. 52-60.

137 AER, *Towards Energy Equity – a strategy for an inclusive energy market – supporting document*, October 2022, pp. 50–61.

138 AGN, *2023–28 Final plan – Attachment 8.2 – Opex Business Cases*, July 2022, p. 77.

policy changes that have occurred since the customer workshops ended in March 2022, including increased energy prices, high inflation and the release of the Victorian Government's *Gas Substitution Roadmap*.

We also note that category specific funding ensures the program will be reviewed and / or discontinued should customers' needs or preferences change in the future. This includes if the program fails to meet expectations or is replaced by other programs. In this regard there may also be more efficient alternatives in the future, noting the AER is exploring the potential for centralised assistance for customers experiencing vulnerability through its *Towards Energy Equity* strategy.[139]

[139] AER, *Towards Energy Equity – a strategy for an inclusive energy market – supporting document*, October 2022 pp.50-61.

Glossary

Term	Definition
ABS	Australian Bureau of Statistics
AER	Australian Energy Regulator
AESCSF	Australian Energy Sector Cyber Security Framework
AGIG	Australian Gas Infrastructure Group
AGN	Australian Gas Networks (Victoria and Albury)
AGN (SA)	Australian Gas Networks (South Australia)
CAM	Cost allocation methodology
Capex	Capital expenditure
CCP28	Consumer Challenge Panel 28
CPI	Cost price index
ECM	Efficiency carryover mechanism
MIL-3	Maturity Indicator Level 3
MGN	Multinet Gas Networks
NER	National Electricity Rules
NGO	National Gas Objective
NGR	National Gas Rules
Opex	Operating expenditure
PSP	Priority service program
RBA	Reserve Bank of Australia
RMP	Risk management program
SP3	Security Profile 3
UAFG	Unaccounted for gas
VCAP	Vulnerable customer assistance program
WPI	Wage price index