Draft decision

Jemena Gas Networks (NSW) access arrangement 2025 to 2030
(1 July 2025 to 30 June 2030)

Attachment 6 – Operating expenditure

November 2024

AUSTRALIAN
ENERGY
REGULATOR

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601
Email: aerinquiry@aer.gov.au
Tel: 1300 585 165

AER reference: AER22005460

Amendment record

Version	Date	Pages
1	29 November 2024	45

List of attachments

This attachment forms part of our draft decision on the access arrangement that will apply to Jemena Gas Networks (NSW) for the 2025–30 access arrangement period. It should be read with all other parts of this draft decision.

The draft decision includes the following documents:

Overview

Attachment 1 – Services covered by the access arrangement (no attachment - covered in the Overview)

Attachment 2 – Capital base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency carryover mechanism

Attachment 9 – Reference tariff setting

Attachment 10 – Reference tariff variation mechanism

Attachment 11 – Non-tariff components

Attachment 12 – Demand

Attachment 13 – Capital expenditure sharing scheme

Contents

6 Operating expenditure

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

This attachment outlines our assessment of Jemena Gas Networks' (JGN) (NSW) proposed opex forecast for the 2025–30 access arrangement period.

6.1 Draft decision

Our draft decision is to include a total opex forecast of $1,161.7 million ($2024–25)[1] for the 2025–30 access arrangement period, excluding ancillary reference services and including debt raising costs.[2] Our draft decision approves higher total forecast opex than JGN proposed (by $6.6 million) because we have added $66.4 million for the forecast costs of small customer connection abolishment. We consider these costs meet the opex criteria[3] and forecasts and estimates criteria.[4]

However, we are not satisfied that JGN's opex forecast, which does not include any costs for small customer connection abolishments, satisfies the opex criteria and the criteria for forecasts and estimates. Our alternative estimate of the total opex forecast, excluding small customer connection abolishments opex, is $1,095.4 million. This is $59.8 million (or 5.2%) lower than JGN's proposed opex forecast.[5] This difference is offset by the $66.4 million for forecast costs of small customer connection abolishments.

Table 6.1 sets out JGN's proposed opex forecast and our alternative estimate, excluding the costs of small customer connection abolishments, and the difference between these forecasts.

1 All numbers are in $2024–25 unless otherwise indicated.

2 JGN proposed to split its current reference service into the Transportation Reference Service and Ancillary Reference Service. This section relates only to opex for gas transportation. For more details, please see: AER, *Final decision – Jemena Gas Networks (NSW) Ltd Access Arrangement 2020–25 – Attachment 1: Services covered by the access arrangement*, June 2020, pp. 5–6.

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

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

5 Our alternative estimate of total forecast opex is not directly comparable with our approved forecast for the current access arrangement period because the latter incudes ancillary reference services opex.

Table 6.1 AER's alternative estimate and draft decision compared to JGN's proposed opex forecast, excluding abolishments opex ($million, 2024–25)

	JGN proposal	AER alternative estimate and draft decision	Difference
Based on reported opex in 2023–24	**1341.7**	**1228.2**	**–113.5**
Base year adjustment New IFRS treatment - SaaS implementation costs in base year	12.3	12.3	–
Base year adjustment Incremental ICT project opex	12.0	10.7	–1.3
Base year adjustment Estimated base year ancillary service opex	–109.3	–	109.3
Total base year adjustments	**–85.0**	**23.0**	**108.0**
2023–24 to 2024–25 increment	**22.5**	**22.6**	**0.0**
Remove category specific forecasts	**–396.0**	**–392.2**	**3.8**
Trend: Output growth	18.8	7.7	–11.1
Trend: Price growth	18.5	18.7	0.2
Trend: Productivity growth	–22.8	–22.3	0.5
Total trend	**14.5**	**4.1**	**–10.3**
Step change: Support for customers experiencing vulnerability	2.7	–	–2.7
Step change: ICT services for new recurrent projects	15.0	14.7	–0.4
Step change: Emissions reduction – Climate change reporting	3.6	–	–3.6
Step change: Emissions measurement – Picarro leak detection services	20.8	–	–20.8
Step change: Pipeline Integrity Management Program	28.1	17.0	–11.2
Step change: License fees	–	24.1	24.1
Total step changes	**70.2**	**55.8**	**–14.5**
Category specific forecasts	177.5	144.3	–33.1
Total opex, excluding debt raising costs	**1145.4**	**1085.9**	**–59.6**
Debt raising costs	9.7	9.5	– 0.2
Total opex, including debt raising costs	**1155.2**	**1095.4**	**–59.8 (–5.2%)**

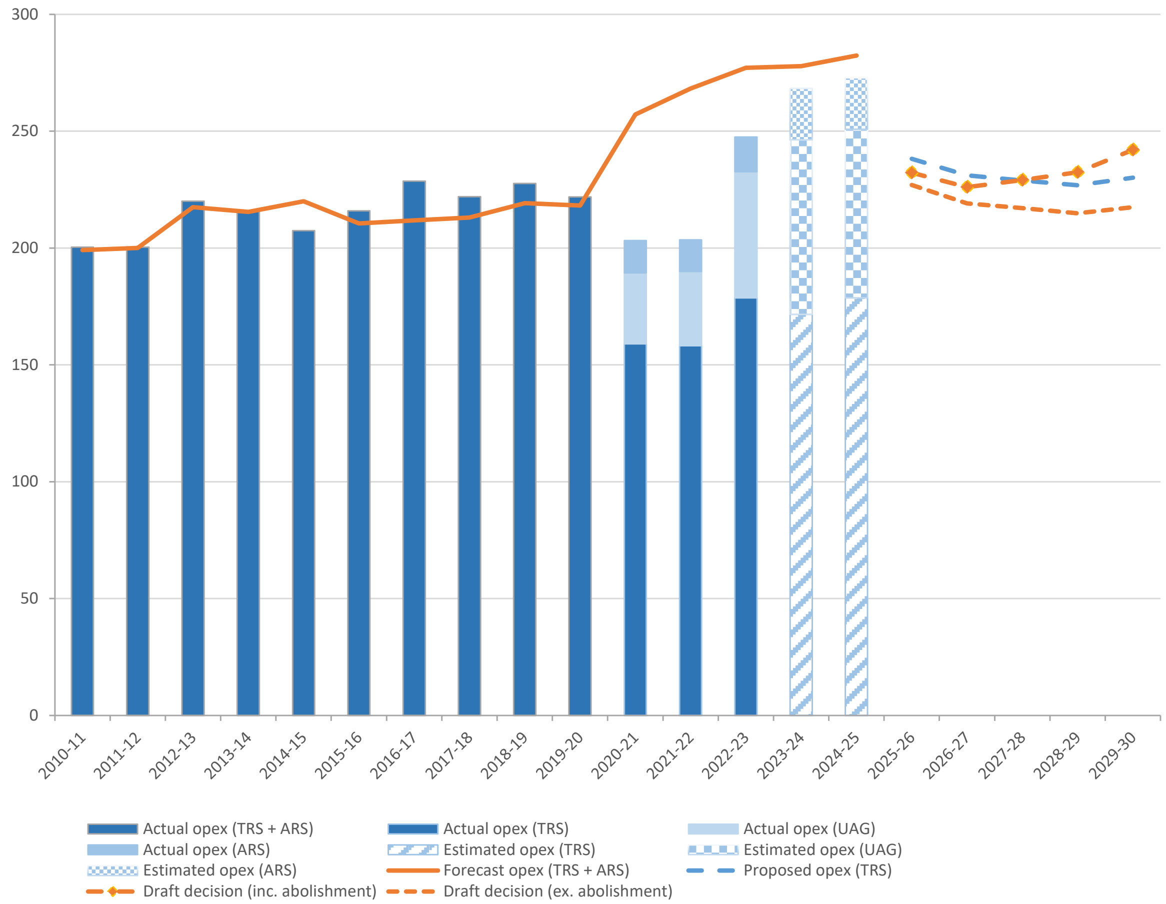
Source: JGN, *2025–30 Access arrangement proposal - Att 6.3M - Operating expenditure forecasting model – 20240628,* June 2024; AER analysis.

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.

Figure 6.1 compares our alternative estimate of opex (including and excluding abolishment costs) to JGN's proposal.[6] We also show the forecasts we approved for the last two access arrangement periods and JGN's actual and estimated opex.

[6] JGN's proposed opex did not include abolishments opex. It proposed abolishments as an ancillary reference service, which we have not accepted. This is further discussed in Attachment 9 of this determination.

Figure 6.1: Comparison of actual and forecast opex ($million, 2024–25)



Source: JGN, *Regulatory accounts*, 2010 to 2023; JGN, *2025–30 Access arrangement proposal - Att 6.3M - Operating expenditure forecasting model,* June 2024; JGN, *Access arrangement, PTRM (multiple periods*: 2010–15, 2015–20, 2020–25); AER analysis.

Note: Includes debt raising costs and movements in provisions.

The inclusion of additional opex for small customer abolishment costs in our alternative estimate of total opex forecast reflects our draft decision to socialise a proportion of small customer connection abolishment costs across transportation reference service tariffs, and establish a discounted ancillary reference service tariff, to ensure the safe operation of the network.[7] This means that a significant proportion of small customer connection abolishment costs will be recovered via transportation reference services opex. This results in higher forecast opex than JGN proposed.

The other key differences between JGN's proposed opex forecast, and our alternative estimate are that we have included:

- a more recent inflation forecast from the Reserve Bank of Australia (RBA)[8]

[7] See section 9.4.5 of Attachment 9 of this draft determination.

[8] RBA, *Statement on Monetary Policy – Appendix: Forecast*, August 2024.

- a lower output growth forecast, which is $11.1 million less than JGN's forecast because we used the customer number forecasts to from our consultant. We use customer number forecasts in our forecast of output growth.
- a lower total amount for step changes, which is $14.5 million less than JGN's proposal, because:
  - we did not include the step change for 'emissions measurement – Picarro leak detection services' because we were not satisfied of the prudency and efficiency of the step change amount proposed by JGN
  - we did not include the step change for 'emission reduction – climate change reporting' because we considered that the costs related to this step change reflect business as usual activities
  - we remove double counting from the step change for pipeline integrity management
  - we also applied minor adjustments to the step change for ICT services for new recurrent projects because we consider JGN did not provide sufficient information to justify the proposed amount.
- a zero forecast for the safeguard mechanism category specific forecast. Instead, we have applied a true up approach to ensure cost recovery by incorporating a factor in the reference tariff variation mechanism.[9]

We discuss the difference between our alternative estimate and JGN's proposal in more detail in section 6.4.

Better Resets Handbook Expectations

Table 6.2 provides our assessment of the extent to which JGN has met the Better Resets Handbook (the Handbook) expectations in relation to forecast opex.[10]

Table 6.2: Better Resets Handbook Expectations

Opex expectations	Comment
1. Opex forecasting approach	JGN applied our standard base-trend-step approach to forecast opex. JGN's opex forecast is consistent with the opex forecast used in the efficiency carryover mechanism (ECM).
2. Base opex	JGN used 2023–24 as the base year, for which audited actual opex is not yet available. For the final decision, we will update the base year opex estimate used in the draft decision. We consider JGN's opex in the base year (2023–24) is not materially inefficient, and we did not make an efficiency adjustment.
3. Trend	JGN adopted our approach of using a weighted average of forecast labour price growth and non-labour price growth to forecast price growth. We do not have a prescribed approach for gas networks output and productivity growth specification. JGN engaged a consultant to provide these estimates. We have tested JGN's proposed output and productivity

9 We discuss this further in Attachment 10.

10 AER, *Better Rests Handbook – Towards consumer-centric network proposals*, December 2021, pp. 24–28.

Opex expectations	Comment
	growth rates and we are satisfied that JGN's approach is reasonable. We adjustment the customer number forecasts as discussed in section 6.4.2.2.
4. Step changes	JGN proposed five step changes, representing 6.5% of total forecast opex. We consider this does not meet our expectation of few or no proposed step changes. We have undertaken a detailed review of the leakage detection (Picarro) program ($20.8 million), the pipeline integrity management program ($28.1 million), and support for customers experiencing vulnerability ($2.7 million). Our assessment of step changes is set out in section 6.4.3.
5. Category specific forecasts	JGN proposed four category specific forecasts, of which three apply to the current period (debt raising costs, unaccounted for gas (UAFG), and government levies and licence fees) and one is new (safeguard mechanism costs). We have undertaken a detailed review of the safeguard mechanism costs ($10.4 million) because it is a new category specific forecast. Our assessment of category specific forecasts is set out in section 6.4.4.
6. Genuine consumer engagement on operating expenditure forecasts	Overall, we consider JGN has demonstrated a genuine approach to consumer engagement in relation to its opex proposal, except with regard to the proposed step change for pipeline integrity management. JGN did not engage with stakeholders on this matter.

6.2 JGN's proposal

JGN's proposal applied a 'base-step-trend' approach to forecast opex, consistent with our preferred approach.[11]

JGN proposed a total opex forecast of $1,155.2 million. This included:[12]

- using an estimate of its opex in 2023–24 as the base from which to forecast (its estimate of $268.3 million in the base year contributes $1,341.7 million to the forecast opex total)
- removing $109.3 million of expenditure on ARS from reported base year opex, which is forecast separately from transportation reference services
- adding $12.3 million to base opex for expenditure on software as a service, which is reported as capex in the 2020–25 access arrangement period
- adding $12.0 million to base opex for incremental ICT projects
- removing $396.0 million of opex, for costs that are forecast on a category specific basis
- adding $22.5 million for the final year increment (from 2023–24 to 2024–25)
- applying a rate of change comprising of:
  - output growth ($18.8 million)

11 JGN, *2025–30 Access arrangement proposal - Att 6.1 - Operating expenditure – 20240628,* June 2024, p. iii

12 JGN, *2025–30 Access arrangement proposal - Att 6.3M - Operating expenditure forecasting model – 20240628,* June 2024

  - price growth ($18.5 million)
  - productivity growth (–$22.8 million)
- adding five step changes totalling $70.2 million for:
  - support for customers experiencing vulnerability ($2.7 million)
  - ICT services for new recurrent projects ($15.0 million)
  - climate change reporting ($3.6 million)
  - Picarro leak detection services ($20.8 million)
  - pipeline integrity management program ($28.1 million)
- adding three category specific forecasts, totalling $177.5 million for:
  - unaccounted for gas (UAFG) costs ($145.8 million)
  - license fees ($21.3 million)
  - safeguard mechanism costs ($10.4 million)
- adding $9.7 million of debt raising costs.

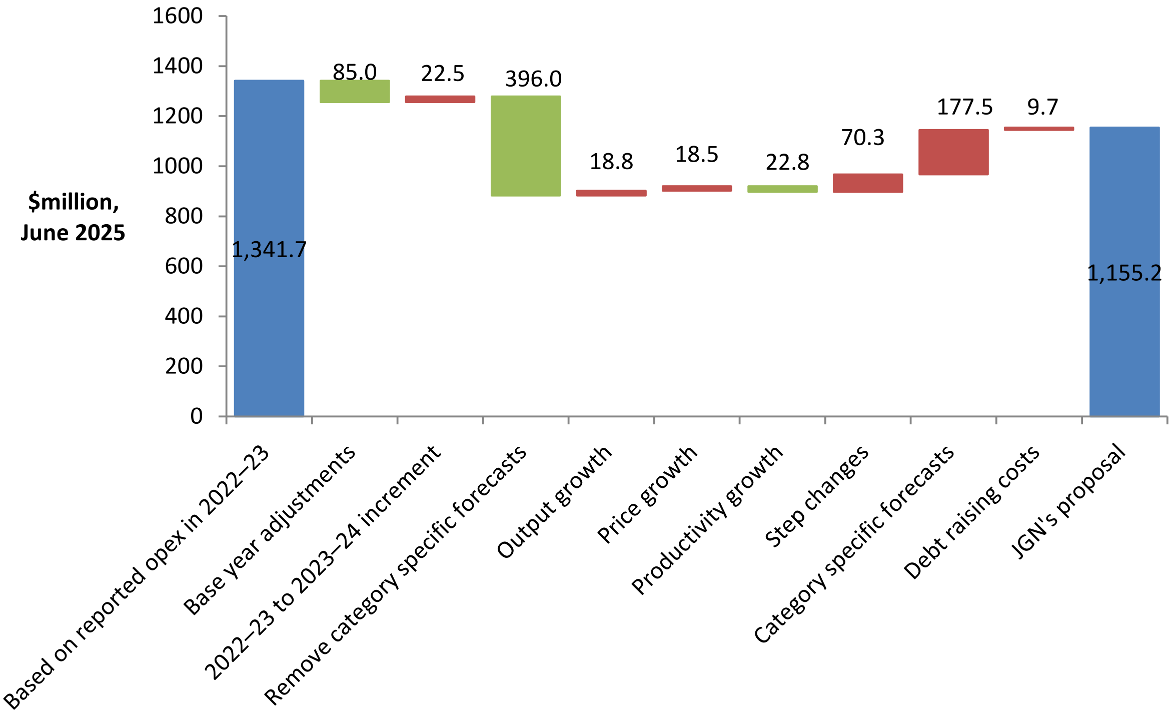
Table 6.3 Proposed forecast opex for the 2025–30 period ($million, 2024–25)

2025–26	2026–27	2027–28	2028–29	2029–30	Total
238.2	231.1	228.9	226.8	230.1	1155.2

Source: JGN, *Att 6.3M – Operating expenditure forecasting model*, June 2024; AER analysis.
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.

Figure 6.2 shows the different components that make up JGN's proposed opex forecast.

Figure 6.2 JGN's proposed opex ($million, 2024–25)



Source: JGN, *Att 6.3M – Operating expenditure forecasting model*, June 2024; AER analysis.

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.

JGN's proposed total opex forecast of $1,155.2 million is $45.9 million, or 4.1%, higher than its actual / estimated opex over the 2020–25 access arrangement period.

6.2.1 Stakeholder views

We did not receive any submissions on JGN's proposal which discussed opex issues.

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.[13]

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.[14]

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.[15]

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

In making this decision, we take into account the reasons for the difference between our alternative estimate and the business's forecast, and the materiality of that difference. We also take into consideration the interrelationships between the opex forecast and other constituent components of our decision, such that our decision is likely to contribute to the achievement of the National Gas Objective (NGO).[16]

---

13 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.

14 NGR, r. 74(2).

15 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'.

16 National Gas Law (NGL), s. 28(1)(a); NGL, s. 23.

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.[17] A key feature of the regulatory framework is that it is based on incentivising networks to be as efficient as possible. We apply incentive-based regulation across the energy networks we regulate, including gas networks. More specifically for opex, we rely on the efficiency incentives created by both ex ante revenue regulation (where forecast opex is approved over a multi-year regulatory period) and the efficiency carryover mechanism (ECM).[18]

The incentive-based regulatory framework partially overcomes the information asymmetries between the regulated businesses and us.[19] 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).[20]

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 regulation, the regulator forecasts efficient aggregate costs over the upcoming regulatory period (of usually five years), which it uses to set a revenue allowance for that period. The business makes higher profits if it reduces costs below those forecast by the regulator. In doing so, the business reveals the efficient costs of delivering the service, which would then influence the regulator’s determination in the next period. Accordingly, incentive

---

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

18 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.

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

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

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

(b) the achievement of targets set by a participating jurisdiction—

(i) for reducing Australia's greenhouse gas emissions; or

(ii) that are likely to contribute to reducing Australia's greenhouse gas emissions.

regulation encourages efficiency while reducing the risks that networks use their monopoly positions to set unreasonably high prices.[21]

Incentive regulation is designed to leave the day-to-day decisions to the network businesses.[22] It allows the network businesses the flexibility to manage their assets and labour as they see fit to comply with the opex criteria[23] and achieve the NGO.[24]

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). 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 forecasting and estimate requirements under the NGR.[25]

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:

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

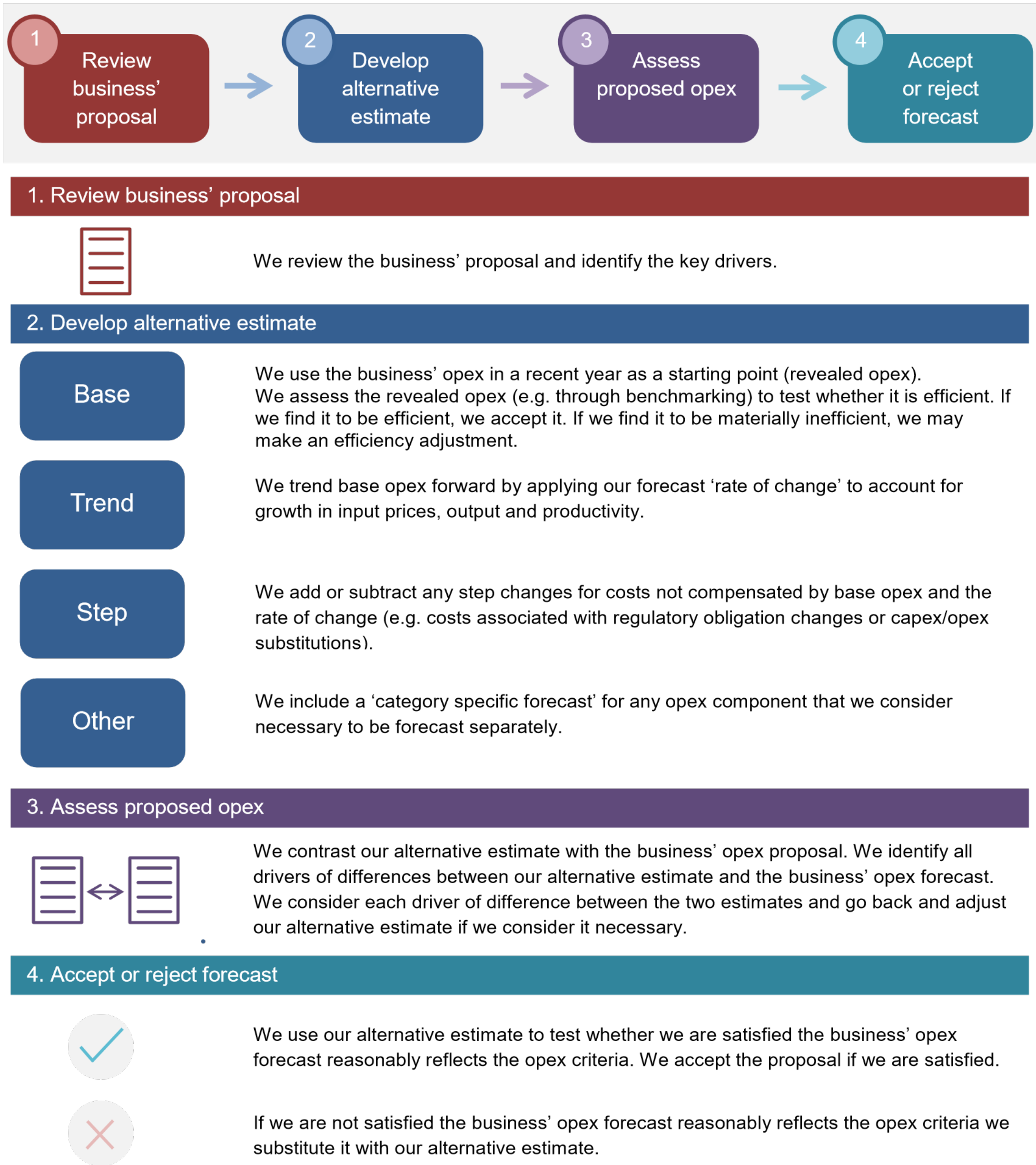
[22] Productivity Commission, *Electricity Network Regulatory Frameworks*, volume 1, No. 62, 9 April 2013, pp. 27–28.

[23] NGR, r. 91.

[24] NGL, s. 28(1)(a) and s. 23.

[25] NGR, r. 74.

Figure 6.3 Our opex assessment approach



6.3.3 Interrelationships

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

- the ECM carryover—the level of opex used as the starting point to forecast opex (the final year of the current access arrangement period (2020–25)) should be the same as the level of opex used to calculate ECM carryovers. This consistency ensures that the business is rewarded (or penalised) for any efficiency gains (or losses) it makes in the final year the same as it would for gains or losses made in other years
- the operation of the ECM in the 2020–25 access arrangement period, which provided JGN an incentive to reduce opex in the base year

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

6.4 Reasons for draft decision

Our draft decision is to include a total opex forecast of $1,161.7 million, excluding ancillary reference services and including debt raising costs.[26] We consider these costs meet the opex criteria[27] and the forecasts and estimates criteria in the NGR.[28]

We are not satisfied that JGN's opex forecast, which does not include any costs for small customer connection abolishments, satisfies the opex criteria and the criteria for forecasts and estimates. Our alternative estimate of the total opex, excluding forecast opex for abolishments, is $1,095.4 million. This is $59.8 million (or 5.2%) lower than JGN's proposed opex forecast.[29]

However, our draft decision approves higher total forecast opex of $1,161.7 million ($6.6 million higher than in JGN's proposal) because we have added $66.4 million for the socialised portion of the forecast costs of small customer connection abolishments.

Table 6.1 sets out JGN's proposal, our alternative estimate (excluding opex for abolishments) that is the basis for the draft decision, and the difference between our draft decision and the proposal.

We have set out the main drivers for the differences in Section 6.1 and we discuss the components of our alternative estimate, and our assessment of JGN'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 JGN needs for the safe and reliable provision of services.

---

26 JGN proposed to split its current reference service into the Transportation Reference Service and Ancillary Reference Service. This section relates only to opex for gas transportation. For more details, please see: AER, *Final decision – Jemena Gas Networks (NSW) Ltd Access Arrangement 2020–25 – Attachment 1: Services covered by the access arrangement*, June 2020, pp. 5–6.

27 NGR, r. 91.

28 NGR, r. 74.

29 Our alternative estimate of total forecast opex is not directly comparable with our approved forecast for the current access arrangement period because the latter incudes ancillary reference services opex.

JGN proposed a base year of 2023–24 and base year opex of $268.3 million or $1,341.7 million over the 2025–30 access arrangement period, including ancillary reference services.[30]

In our alternative estimate, we also used 2023–24 as the base year but used a base year opex of $245.6 million or $1,228.2 million over 5 years to form our alternative estimate of forecast opex. Our base year opex is lower than that of JGN's because we have excluded ancillary services prior to any other adjustments.[31]

JGN's estimated opex in the base year of 2023–24 is $9.5 million or 3.4% lower the forecast opex we approved in our last determination. Estimated opex in 2023–24 is higher than actual annual opex over the period 2020–2022. JGN explained that this was due to halting many operational activities because of COVID-19 lockdowns.[32] JGN added that the reductions to opex were offset by a material increase in UAFG replenishment costs in 2022–23 and 2023–24.

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

JGN submitted gas distribution benchmarking analysis undertaken for it by CEG to support its view that its base year was efficient.[33] CEG's benchmarking analysis compared the performance of 12 gas distribution businesses over the period 1999–2023 to assess the relative opex efficiency of JGN using various productivity indices, partial performance indicators and econometrics.[34] CEG reported that JGN consistently ranked in the top two or three gas distribution businesses in terms of opex per customer,[35] noting that JGN ranked first in 2022.[36] When real opex per customer was regressed against a number of key determinants (customer density, scale and climate) JGN's normalised opex per customer over the 2015–2019 period was slightly higher than the sample average. Further, when using a real opex cost model and opex is regressed against a number of explanatory variables such as customer numbers, mains length, capital stock, environmental variables and time variables, JGN had below average normalised opex in 2023.[37]

CEG also undertook opex multilateral partial factor productivity benchmarking for JGN over the 1999–2023 period and showed that JGN was the most efficient Australian gas distribution business over 2022–23.[38]

---

30 JGN, *2025–30 Access arrangement proposal – Att 6.3M – Operating expenditure forecasting model*, June 2024.

31 Our approach and that applied by JGN yield the same outcome.

32 JGN, *2025–30 Access arrangement proposal – Att 6.1 – Operating expenditure*, June 2024, p. 6.

33 CEG, *Benchmarking and forecasting JGN opex A report for Jemena Gas Networks*, April 2024.

34 CEG, *Benchmarking and forecasting JGN opex A report for Jemena Gas Networks*, April 2024, p. 3.

35 CEG, *Benchmarking and forecasting JGN opex A report for Jemena Gas Networks*, April 2024, p. 4.

36 CEG, *Benchmarking and forecasting JGN opex A report for Jemena Gas Networks*, April 2024, p. 5.

37 CEG, *Benchmarking and forecasting JGN opex A report for Jemena Gas Networks*, April 2024, pp. 12–13.

38 CEG, *Benchmarking and forecasting JGN opex A report for Jemena Gas Networks*, April 2024, pp. 25–26.

Our assessment of the efficiency of opex in the base year has been informed by the benchmarking studies undertaken by CEG. While this does not include updated data for 2023–24 or 2024–25, we consider that the results are indicative of the broader performance of JGN, including in the proposed base year. We consider the information provided suggests that JGN's base opex is likely to be efficient. We note that JGN's opex was also subject to the incentives of the ECM over the 2020–25 access arrangement period. 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 opex above efficient levels in the proposed base year.[39]

In summary, we have not identified any evidence that JGN's proposed 2023–24 base year is materially inefficient. By the time of our final decision, it will be the most recent year with complete actual data. We consider it to be an appropriate choice of base year.

6.4.1.1 Adjustments to base year opex

JGN proposed total adjustments to its estimated $1,341.7 million base opex, of –$17.0 million or –$85.0 million over the five years. JGN adjusted its estimated base opex for SaaS costs, incremental ICT project opex and ancillary reference services opex (as shown in Table 6.1).

We have adjusted our alternative estimate of opex in the base year of $1,228.2 million by $4.6 million or $23.0 million over 5 years to:

- add $2.5 million for SaaS costs in the base year. This increases our alternative estimate of total opex by $12.3 million over 5 years
- add $2.1 million for incremental ICT project opex. This increases our alternative estimate of total opex by $10.7 million over 5 years.

We did not adjust our alternative estimate of opex in the base year to exclude ancillary reference services opex. This is because our lower base year opex compared to that of JGN ($1,228.2 million compared to $1,341.7 million) already excludes ancillary reference services opex.

Otherwise, the adjustments we have made in our alternative estimate are broadly consistent with those in JGN's proposal. These are discussed further below.

SaaS costs

JGN proposed an adjustment to its base year opex for its current SaaS implementation costs, which amounts to $2.5 million, or $12.3 million over the 2025–30 access arrangement period. We have included the full amount of this base adjustment in our alternative estimate.

Changes to international accounting standards in 2021 require SaaS implementation costs to be expensed rather than capitalised, to recognise the fact that the entity does not control the

---

39 NGR, r. 71(1).

underlying asset. Treating these costs as opex (as opposed to capex) is consistent with our recent determinations.[40]

Consistent with this guidance, JGN moved its SaaS implementation costs from the current 2020–25 access arrangement period's capex allocation, to opex in the 2025–30 period. This base adjustment has no overall impact on JGN's total expenditure.

Given this is consistent with the accounting treatment of these costs and our previous determinations, we have included these costs in our alternative estimate.

Incremental ICT project opex

JGN proposed an adjustment to its base year opex for an increase in its non-recurrent ICT costs. These costs amount to $2.4 million per year, or $12.0 million over the 2025–30 regulatory period. We have accepted most of these costs and have included an adjusted amount of $2.1 million per year, or $10.7 million over 5 years, in our alternative estimate. This is 11.0% lower than JGN's forecast. We explain our reasoning below.

JGN stated that it would require an incremental increase to its ICT opex to move and expand its current ICT capability from a traditional on-premises model to a cloud-based, subscription model and to maintain legal and regulatory compliance.[41] The ICT projects that form the basis of this expenditure have both a non-recurrent (i.e. SaaS implementation and customisation) component and an ongoing/recurrent (i.e. subscription and maintenance fee) component.[42] JGN proposed to treat the non-recurrent component of these costs as a base adjustment, to maintain consistency with how it had treated its current SaaS implementation costs (described above), and the recurrent component as a step change for similar reasons.[43]

These incremental ICT projects and their associated non-recurrent opex expenditure are listed below in Table 6.4, as outlined in JGN's proposal.

---

40 For example: AER, *Final Decision Attachment 6 – Operating expenditure – Ausgrid – 2024–29 Distribution revenue proposal*, April 2024; AER, *Draft Decision Attachment 6 – Operating expenditure – SA Power Networks – 2025-30 Distribution revenue proposal,* September 2024.

41 JGN, *2025–30 Access arrangement proposal –Att 5.4 – Technology plan*, June 2024, p. 1.

42 JGN, *2025–30 Access arrangement proposal – Att 5.4 – Technology plan*, June 2024, pp. 24–27.

43 There is also a capex component to some of these costs.

Table 6.4 Forecast non-recurrent ICT project opex

Non-recurrent ICT sub-categorisation	Project name	2023$M	2025$M
Maintaining existing services, functionalities, capability, and/or market benefits	SAP Upgrade	6.97	7.4
	Gas Retail Market Settlement – Major Application Lifecycle	0.29	0.3
Complying with new/altered regulatory obligations / requirements	Data Foundations and Governance	2.04	2.2
	Enterprise Content Management Uplift	4.78	5.1
	Cybersecurity Program	7.10	7.6
	Contract Lifecycle Management	0.99	1.1
New or expanded ICT capability, functions, and services	Asset Investment Planning	1.00	1.1
	Network Management Advanced Analytics	4.02	4.3
	Chronic No Access Digital Metering pilot	1.24	1.3
	Works Management Extend Phase	2.99	3.2
Total non-recurrent ICT project opex 2025-30 (a)		**31.42**	**33.5**
Average annual non-recurrent ICT project opex 2025-30 (b=a/5)			6.7
Less non-recurrent ICT project opex in base year (c)			-4.3
Net increase in base year opex for non-recurrent ICT project opex (b)-(c)			**2.4**

Source: JGN, *2025–30 Access arrangement proposal - Att 6.1 - Operating expenditure*, June 2024, p. 16.

Consistent with our guidance on assessing non-network ICT costs,[44] we have first assessed JGN's proposed total (capex and opex, non-recurrent and recurrent) ICT expenditure from a top down historical/trend perspective. We have then analysed each of JGN's ICT projects above from a bottom-up perspective, having regard to JGN's provided technology plan[45] and investment brief for each project,[46] which sets out the business or regulatory need for the project and the accompanying option analysis.

We found that JGN's total ICT expenditure is largely consistent with its expenditure in the current 2020–25 access arrangement period. This suggests that the incremental increase in its opex ICT costs (both non-recurrent and recurrent) is predominantly offset by an approximately equal decline in its capex costs. We are also satisfied that most of the projects above are required, or reflect a justifiable business need by JGN, and are in line with industry trends. We also consider, having regard to the option analysis and cost build-up of these projects, that their associated expenditure is largely prudent and efficient.

However, we do have some concerns with the following projects:

[44] AER, *Guidance Note – Non-network ICT capex assessment approach for electricity distributors*, November 2019, pp. 9–11.

[45] JGN, *2025–30 Access arrangement proposal – Att 5.4 – Technology plan*, June 2024.

[46] JGN, *2025–30 Access arrangement proposal – Att 5.4 – Technology plan*, June 2024, p. 40.

- **Chronic no-access digital metering pilot**: We have not included the opex forecast related to the overall project of JGN replacing 8,000 end of life chronic no access meters with remote meters. The reasons for this decision are set out in the capex attachment (Attachment 5). This lowers our alternative estimate by $0.26 million per year, or $1.3 million in total (which forms the non-recurrent opex cost of this project). This project also includes a minor recurrent component, included as part of JGN's recurrent ICT step change, which we have also excluded from our alternative estimate (see section 6.4.3.2).
- **Cloud capacity growth**: JGN forecast an annual 15% increase in its requirement for cloud storage and processing.[47] We consider that JGN's forecast growth rate for these services appears excessive. Having considered the information provided in JGN's proposal and its response to our requests for additional information, we do not consider that JGN has sufficiently justified the basis for this forecast. While we have used JGN's costs for this project as a placeholder for our draft decision, we request that JGN provide additional information in its revised proposal to support the proposed forecast opex.
- **Contract lifecycle management:** JGN has identified the need for this project and the costs, in our view, appear likely to be prudent and efficient. However, we consider there may be potential savings in some of JGN's ongoing costs following the completion of this project. Therefore, at this stage we used JGN's proposed amount as a placeholder for this project. We request that JGN provide further clarification, as part of its revised proposal, to enable us to form a view on the efficient amount required for this project net of any savings for our final determination.

As a result of our analysis above, we have included a base adjustment of $2.1 million per year, or $10.7 million over five years, in our alternative estimate. This is $1.3 million over five years or 11.0% lower than JGN's forecast.

6.4.1.2 Removal of category specific forecasts

In some circumstances we remove a category of opex from the base year expenditure if it is more appropriate to forecast that category separately. We refer to these as 'category specific forecasts' (see section 6.4.4).

We have removed unaccounted for gas (UAFG) and debt raising costs from base opex, to be forecast separately. This is consistent with our standard approach as well as JGN's proposal. JGN also removed the jurisdictional charges it incurred in the base year because it proposed that these be forecast on a category specific basis. For the reasons discussed in section 6.4.4, we do not consider jurisdictional charges should be treated as a category specific forecast.

Accordingly, we have removed $392.2 million from base opex for the costs we forecast as category specific forecasts. This is less than the $396.0 million that JGN removed because

---

47 JGN, *2025–30 Access arrangement proposal - RIN – 4.4 – ICT Investment Brief – Cloud Capacity Growth*, June 2024, p. 5.

we did not remove jurisdictional charges from base opex.[48] We consider that these charges should be included in base opex as discussed in section 6.4.3.6.

6.4.1.3 Final year increment

Our standard approach to estimating final year opex is to add the forecast change in opex between the base year (2023–24) and the final year (2024–25) to the base year opex amount.[49]

We have included $22.6 million for the final year increment in our alternative estimate, which is marginally more than JGN's proposed amount of $22.5 million.[50] The variance between our estimate of the final year increment and JGN's proposal is because we used more recent inflation figures, which were not available at the time of JGN's proposal.

6.4.2 Rate of change

Having estimated opex in the final year of the 2020–25 period, we then applied a forecast annual rate of change to forecast opex for the 2025–30 access arrangement period. We have applied an average annual rate of change of 0.0% to derive our alternative estimate of opex. This is lower than JGN's forecast of 0.5%. We compare both forecasts in Table 6.5.

Table 6.5 Forecast annual rate of change in opex, %

	2025–26	2026–27	2027–28	2028–29	2029–30
JGN's proposal					
Output growth	0.8	0.7	0.6	0.6	0.4
Price growth	0.9	0.6	0.6	0.7	0.7
Productivity growth	0.9	0.9	0.9	0.9	0.9
Rate of change	**0.8**	**0.5**	**0.3**	**0.4**	**0.3**
AER alternative estimate					
Output growth	0.4	0.4	0.3	0.1	–0.1
Price growth	1.0	0.6	0.5	0.6	0.8
Productivity growth	0.9	0.9	0.9	0.9	0.9
Rate of change	**0.6**	**0.1**	**–0.1**	**–0.1**	**–0.2**
Difference	–0.3	–0.4	–0.5	–0.5	–0.5

Source: JGN, *Att 6.3M – Operating expenditure forecasting model*, June 2024; AER analysis.

48 JGN, *2025–30 Access arrangement proposal – Att 6.3M – Operating expenditure forecasting model*, June 2024.

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

50 JGN, *2025–30 Access arrangement proposal – Att 6.1 – Operating expenditure*, June 2024, p. 10.

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 that of JGN's are that:

- we have used more recent wage price index (WPI) forecasts to forecast labour price growth
- we have used a different forecast of customer numbers to forecast output growth.

We discuss each of these issues below.

6.4.2.1 Forecast price growth

JGN proposed average annual price growth of 0.7%, which increased its total opex forecast by $18.5 million. We have used different annual price growth rates in our alternative estimate of total opex that also averaged 0.7%. The price growth rates we used increase our total opex alternative estimate by $18.7 million.

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

- both we and JGN used an average of two WPI growth forecasts for the electricity, gas, water and waste services (utilities) industry in NSW to forecast labour price growth. JGN used forecasts from its consultant, Oxford Economics, and from KPMG.[51] It sourced the KPMG forecasts from our draft decision for New South Wales 2024–29 electricity distribution regulatory determination. In our alternative estimate, we have replaced the KPMG forecasts with more recent forecasts from our consultant Deloitte Access Economics.[52]
- both we and JGN applied a forecast non-labour real price growth rate of zero
- both we and JGN have applied the same weights to account for the proportions of opex that is labour and non-labour, being 62% and 38%, respectively.

Consequently, the key difference between our real price growth forecasts and JGN's is that we have updated our labour price growth forecast to include the more recent forecasts from Deloitte Access Economics, instead of the older KPMG forecasts.

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 Deloitte Access Economics to provide WPI growth forecasts for the New South Wales utilities industry.

---

51 JGN, *2025–30 Access arrangement proposal - Att 6.1 - Operating expenditure – 20240628*, June 2024, p. 18.

52 Deloitte Access Economics, *Labour price growth forecasts*, 20 August 2024, p. 10.

Consistent with this approach, JGN used forecasts from its consultant, Oxford Economics, and KPMG. It sourced the KPMG forecasts from our draft decisions for the 2024–29 electricity distribution determinations.

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

We show the labour price growth forecasts from Oxford Economics, Deloitte Access Economics and the average WPI growth rate in Table 6.6. 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.[53] We do this because the WPI does not include superannuation and thus the WPI growth forecasts do not capture the increase in the price of labour when the superannuation guarantee increases.

Table 6.6 Forecast labour price growth, %

	2025–26	2026–27	2027–28	2028–29	2029–30
WPI growth – DAE	1.1	0.8	0.7	0.9	1.1
WPI growth – Oxford Economics	1.2	1.1	0.9	1.2	1.3
Average WPI growth	1.1	1.0	0.8	1.0	1.2
Superannuation guarantee increase	0.5	–	–	–	–
Forecast labour price growth	**1.6**	**1.0**	**0.8**	**1.0**	**1.2**

Source: Oxford Economics, *Labour price escalation forecast 2025–26 to 2029–30*, April 2024, p. 4; Deloitte Access Economics, *Labour price growth forecasts*, 20 August 2024, p. 10; 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.

6.4.2.2 Forecast output growth

JGN proposed average annual output growth of 0.6%, which increased its proposed opex forecast by $18.8 million. We have forecast average annual output growth of 0.2%. This increases our alternative estimate of total opex by $7.7 million.

Assessment of output growth

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

To assess JGN's output and productivity growth forecasts, we tested how the proposed output growth, net of productivity growth, compares to the output and productivity growth forecast using the output specifications derived from the available econometric studies. These econometric studies have been submitted in previous gas reset processes and were

53 ATO, *Super guarantee*, https://ato.gov.au/SuperRate, accessed on 20 November 2024.

undertaken between 2015 and 2022.[54] We have taken the opex cost functions estimated by each of these studies and forecast output and productivity growth using the forecast growth in energy throughput, customer numbers, mains length and the regulated asset base. In this way we have produced output and productivity growth forecasts specific to JGN'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 tends to also give higher forecast productivity growth.

When we compared JGN's average annual output growth net of productivity growth of –0.2% against the forecasts based on each of the available econometric studies, we found it to be within the reasonable range formed by the studies, as shown in Table 6.6. Consequently, we are satisfied that JGN's forecast of output growth, net of productivity growth, is reasonable in these circumstances.[55]

Table 6.7 Comparison of forecast output growth net of productivity growth

Model Specification	Output growth	Productivity growth	Output growth net of productivity growth
JGN proposal	0.6	0.9	–0.2
ACIL Allen (2016)	–0.2	0.6	–0.7
Economic Insights (2015)	–0.5	0.6	**–1.1**
ACIL Allen (2016)	–0.1	0.6	–0.7
Economic Insights (2016)	0.3	0.8	–0.5
Economic Insights (2019)	0.2	1.2	–1.0
ACIL Allen (2022)	–0.0	0.1	–0.1
CEG (2024)	0.2	0.1	**0.1**

Source: JGN, *2025–30 Access arrangement proposal - Att 6.3M – Operating expenditure forecasting model*, June 2024; AER analysis

Note: Amounts of '0.0' and '–0.0' represent small non-zero values and '–' represents zero.

Customer numbers

For our alternative estimate, we have calculated JGN's output growth using the customer number forecast for the 2025–30 period as estimated by our consultant, ACIL Allen, as part of its assessment of JGN's demand forecast.[56] This aligns with the demand forecast used for our capex decision.

54 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.

55 NGR, r. 74(2).

56 ACIL Allen, *Review of Jemena Gas Network's demand forecasts*, 8 November 2024.

Notably, ACIL Allen's customer number forecast for JGN, like JGN's reset RIN customer numbers,[57] excluded JGN's disconnected customers[58]. In its proposed opex forecast JGN included disconnected customers as part of its customer number estimate, hence its higher ($18.8 million) forecast.

JGN submitted it had included customers who were disconnected as these customers still required opex costs for inspecting and maintaining these disconnected services. JGN also submitted that it had adopted this approach in its previous, 2020–25, access arrangement.[59]

JGN showed, in Table 6.8 below, that the difference between its reset RIN customer numbers (the first row below titled 'average customer numbers', which are more aligned with ACIL Allen's forecast), and the customer number forecast in its opex model (last row), is due to a forecast material increase in disconnected customers over the 2025–30 period.

Table 6.8 Reconciliation between JGN customer numbers in its most recent RIN and opex model

Customer numbers	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Average customer numbers - Table 2	1,543,879	1,557,856	1,565,351	1,566,358	1,557,696	1,532,131
Temporary disconnections	35,798	40,678	47,997	58,975	77,637	111,231
Row 1 plus row 2	1,579,677	1,598,534	1,613,348	1,625,333	1,635,333	1,643,362
JGN opex model	**1,579,677**	**1,598,534**	**1,613,348**	**1,625,333**	**1,635,333**	**1,643,362**

Source: JGN, *Response to Information Request IR#004 – further information on opex trend*, 27 August 2024, p. 1.

We have used ACIL Allen's lower customer number forecasts, which do not include disconnected customers, to estimate JGN's output growth, for the following reasons:

- We consider these customer number forecasts, based on our consultant's assessment, to be more accurate than those in JGN's opex model. These are also the number used in our capex demand assessment for JGN.
- In this draft decision, we have determined that JGN socialise a significant portion of its abolishment fee for residential customers as part of its 2025–30 pricing decision (see Attachment 9). In other words, the cost of an abolishment for a residential customer will be lowered from $1,472 to $250 (approximately), with the difference in costs socialised amongst all of JGN's gas customers. This will likely encourage more customers who are disconnected from JGN's network over the 2025–30 period to seek an abolishment (as

57 JGN, *2025–30 Access arrangement proposal - RIN – Att 3 – Workbook 1 – Forecast*, June 2024.

58 We have assumed that a disconnected customer is a customer who is not connected to JGN's network but has not yet had the permanent removal of JGN's meter and associated network infrastructure (i.e. an abolishment).

59 JGN, *Response to Information Request IR#004 - further information on opex trend,* 27 August 2024, p. 1.

there will be less of a financial barrier). This will reduce the total number of disconnected customers over the 2025–30 period compared to JGN's forecast.

- We understand that any customer number forecasts used in CEG's econometric analysis do not include disconnected customers.

We asked JGN if it could provide an estimate for what proportion of its disconnected customers would seek an abolishment if there was no difference in the financial incentive between the two methods of leaving its network. JGN did not provide this estimate.[60] Therefore, as a placeholder for our draft decision, we have assumed that all of these disconnected customers would seek an abolishment, given that ACIL Allen's customer number forecasts do not include these disconnections. However, we accept that at least a portion of these disconnected customers will not seek an abolishment if the cost was the same as a disconnection, and will liaise with JGN on this issue for its revised proposal.

6.4.2.3 Forecast productivity growth

JGN forecast average annual productivity growth of 0.9% in its proposal.[61] We have also included forecast average productivity growth of 0.9% in our alternative estimate.

The econometric analysis conducted by CEG in 2024, and submitted by JGN, found positive returns to scale. The econometric results also indicated a reduction in customer density will likely reduce productivity growth. CEG's 2024 study also included both lower, negative, output growth and a reduction in customer density (compared to JGN's previous determination). Both factors should put upwards and downwards pressure (respectively) on productivity growth.

We note that to forecast productivity growth, CEG only included technical change (in the form of a time trend variable) as part of its econometric analysis. Our preferred approach, as specified in previous access arrangements, is to include technical change as well as returns to scale and changes in business conditions to forecast productivity. However, because JGN's forecast of output growth net of productivity growth falls within the reasonable range of previous econometric studies (Table 6.6. above), and since the forecast effect of a change in business conditions usually offsets the effect of forecast returns to scale, we have adopted JGN's proposed productivity growth in our alternative estimate.

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.[62]

---

60 JGN, *Response to Information Request IR#017 – Abolishments, Tariffs and Prudent Discounts*, 4 October 2024, pp.5–6.

61 JGN, *2025–30 Access arrangement proposal - Att 6.1 - Operating expenditure*, June 2024, p. 19.

62 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, October 2024, p. 26.

JGN's proposal included five step changes totalling $70.2 million or 6.1% of its proposed total opex forecast.[63] These are shown in Table 6.9, along with our alternative estimate for the draft decision, which is to include step changes totalling $55.8 million. The difference is largely because we have not included the step changes for:

- support for customers experiencing vulnerability, which we have instead included as a category specific forecast as discussed in section 6.4.3.1
- climate change reporting, which we discuss in section 6.4.3.3
- Picarro leak detection services, which we discuss in section 6.4.3.4.

Further, we have added forecast licence fees as a step change, not as a category specific forecast as proposed by JGN. We discuss this in section 6.4.3.6.

Table 6.9 Step changes ($million, 2024–25)

Step change	JGN proposal	AER Draft decision	Difference
Support for customers experiencing vulnerability	2.7	–	–2.7
ICT services for new recurrent projects	15.0	14.7	–0.4
Emissions reduction – Climate change reporting	3.6	–	–3.6
Emissions measurement – Picarro leak detection services	20.8	–	–20.8
Pipeline Integrity Management Program	28.1	17.0	–11.2
License fees	–	24.1	24.1
Total	**70.2**	**55.8**	**–14.5**

Source: JGN, add reference; 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.

6.4.3.1 Support for customers experiencing vulnerability

We have included $2.7 million of forecast opex for the 'Support for customers experiencing vulnerability' program. This is consistent with the amount proposed by JGN. We are satisfied that including these costs in our alternative estimate would result in a total opex forecast that satisfies the opex criteria. However, we have included these costs as a category specific forecast, not as a step change as proposed by JGN. This is consistent with our previous decisions on customer vulnerability proposals,[64] and ensures forecast opex, including any underspends, does not result in rewards through JGN's Efficiency Carryover Mechanism.

63 JGN, *2025–30 Access arrangement proposal – Att 6.1 – Operating expenditure – 20240628*, June 2024, p. 20.

64 AER, *Final decision – AGN(SA) access arrangement 2021–26 – Attachment 6 – Operating Expenditure*, 30 April 2021, pp. 22–25.

Table 6.10: Support for customers experiencing vulnerability step change ($million, 2024–25)

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
JGN's proposal	0.5	0.5	0.5	0.5	0.5	**2.7**
AER alternative estimate	–	–	–	–	–	**–**
Difference	–0.5	–0.5	–0.5	–0.5	–0.5	**–2.7**

Source: JGN, *2025–30 Access arrangement proposal – Att. 6.3M – Operating expenditure forecasting model,* June 2024; AER analysis.
Note: Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

JGN proposed a step change of $2.7 million to support customers experiencing vulnerability.[65] JGN stated that it already undertakes several initiatives to support vulnerable customers, including Voices for Power, the Uniting Energy Assist Program, an Aboriginal Workforce Mentoring program, and an annual Community Grants Program.[66] During stakeholder engagement, JGN sought feedback on expanding its programs, with customers broadly supporting an enhancement of customer vulnerability programs.[67] JGN further clarified that these enhancements were collaboratively designed with stakeholders, and will proceed with an uplift to internal resources, the Home Gas Audits and Emergency Appliance Repair program, and Information Hub initiative.[68]

We assessed the information provided in JGN's proposal, and sought further information through an information request on the details of its proposed programs.[69] JGN confirmed that it does not intend to replace customers' appliances, but rather focus to assist on the repair of these.

We are satisfied that the amounts proposed are both efficient and based on the support received during JGN stakeholder engagement, represent prudent expenditure that responds to consumer preferences.

For our alternative estimate, we have included the $2.7 million proposed by JGN as a category specific forecast. This means that the ongoing need for, and effectiveness of, these initiatives can be assessed as part of future access arrangement determinations. It also ensures forecast opex, including any underspends, does not result in rewards for JGN through the Efficiency Carryover Mechanism.

6.4.3.2 ICT services for new recurrent projects

We have included $14.7 million of opex for 'ICT services for new recurrent projects. This is 2.5%, or $0.4 million lower than the amount proposed by JGN. We are satisfied that adding

65 JGN, *2025–30 Access arrangement proposal – Att. 6.2 – Opex step changes justification, June 2024,* p. 5.

66 JGN, *2025–30 Access arrangement proposal – Att. 6.2 – Opex step changes justification, June 2024,* pp. 4–5.

67 JGN, *2025–30 Access arrangement proposal – Att. 6.2 – Opex step changes justification, June 2024,* pp. 5–6.

68 JGN, *2025–30 Access arrangement proposal – Att. 6.2 – Opex step changes justification, June 2024,* pp. 8–9.

69 JGN, r*esponse to Information request IR#013*, Q1(a), 4 October 2024, pp. 1–3.

these costs to our alternative estimate would result in a total opex forecast that satisfies the opex criteria (all things being equal).

JGN proposed a $15.0 million step change for an increase in its recurrent expenditure related to new or expanded ICT projects for the 2025–30 regulatory period.

Table 6.11: ICT for recurrent projects step change ($million, 2024–25)

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
JGN's proposal	0.8	2.3	3.8	3.9	4.3	15.0
AER alternative estimate	0.7	2.2	3.7	3.9	4.3	14.7
Difference	–0.1	–0.1	–0.1	–0.1	–0.1	–0.4

Source: JGN, *2025–30 Access arrangement proposal - Att. 6.3M – Operating expenditure forecasting model,* June 2024; AER analysis.
Note: Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

As discussed in section 6.4.1.1, JGN submitted that it would require an incremental increase to its ICT opex necessitated by moving and expanding its current ICT capability from a traditional on-premises model to a cloud-based, subscription model, and to maintain legal and regulatory compliance.[70] The ICT projects that formed the basis of this expenditure had both a non-recurrent (i.e. SaaS implementation and customisation) component and an ongoing/recurrent (i.e. subscription and maintenance fee) component.[71] JGN proposed to treat the non-recurrent component of these costs as a base adjustment, to maintain consistency with how it had treated its current SaaS implementation costs, and the recurrent component as a step change for similar reasons. There is also a capex component to some of these costs.

These incremental ICT projects and their associated recurrent opex expenditure are listed below in Table 6.12, which has been reproduced from JGN's proposal.

[70] JGN, *2025–30 Access arrangement proposal – Att 5.4 – Technology plan*, June 2024, p. 1.
[71] JGN, *2025–30 Access arrangement proposal – Att 5.4 – Technology plan*, June 2024, pp. 24–27.

Table 6.12 Forecast incremental recurrent ICT project opex

Non-recurrent ICT sub-categorisation	Initiative Name	Recurrent-step opex
Maintaining existing services, functionalities, capability, and/or market benefits	Gas Retail Market Settlement – Major Application Lifecycle	0.09
	Geospatial systems lifecycle management	0.59
	Cloud Capacity Growth	3.48
Complying with new/altered regulatory obligations / requirements	Enterprise Content Management	0.82
	Data Foundations and Governance	0.83
	Cybersecurity Program	2.95
	Contract Lifecycle Management	0.73
New or expanded ICT capability, functions, and services	Asset Investment Optimisation	2.98
	Network Management Advanced Analytics	2.19
	Chronic No Access Digital Metering pilot	0.38

Source: JGN, *2025–30 Access arrangement proposal – Att 6.2 – Opex step change justification*, June 2024, p. 13.

Our assessment of this step change is the same as our assessment of JGN's proposed non-recurrent incremental ICT project opex (which is outlined in section 6.4.1.1 of this attachment). This is because most of the ICT projects in Table 6.12 are the associated ongoing/recurrent costs to the non-recurrent implementation and customisation costs proposed in section 6.4.1.1.

As outlined in section 6.4.1.1, we have some concerns with the following projects:

- **Chronic no-access digital metering pilot**: We have not included this project in our draft decision on forecast capex, as discussed in Attachment 5. Consequently, we have excluded the related ICT opex expenditure from our alternative estimate. This lowers our alternative estimate for this step change by $0.4 million in total.
- **Cloud capacity growth**: We have used JGN's forecast as a placeholder but will seek further information from JGN to inform our final decision.
- **Contract Lifecycle Management:** We have used JGN's forecast as a placeholder but will seek further information from JGN to inform our final decision.
- **Asset Investment Optimisation:** We support the benefits of this project, and the associated costs appear prudent and efficient – pending confirmation that there are not any related opex savings. We will seek further information from JGN to inform our final decision.

As a result of our analysis above, we have included a step change of $14.7 million over 5 years in our alternative estimate of forecast opex. This is $0.4 million or 2.5% lower than JGN's forecast.

6.4.3.3 Emissions reduction – Climate change reporting

JGN proposed a step change of $3.6 million to comply with new obligations related to the Exposure Draft SR1 Australian Sustainability Reporting Standards – Disclosures of Climate-related financial information.[72] We have not included this step change in our alternative estimate because we do not consider this step change to be prudent or efficient. The proposed amounts may double count the costs JGN received through our opex forecasting approach. We further consider this step change is inconsistent with our published step change guidance.[73]

Table 6.13: Emissions reduction – climate change reporting step change ($million, 2024–25)

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
JGN's proposal	0.8	0.7	0.7	0.7	0.7	3.6
AER alternative estimate	–	–	–	–	–	–
Difference	**–0.8**	**–0.7**	**–0.7**	**–0.7**	**–0.7**	**–3.6**

Source: JGN, *2025–30 Access arrangement proposal – Att. 6.3M – Operating expenditure forecasting model,* June 2024; AER analysis.
Note: Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

In its proposal, JGN stated that from 1 January 2025, it expects to have new emission reporting obligations based on the Exposure Draft SR1 Australian Sustainability Reporting Standards – Disclosure of Climate-related Financial information, as developed by the Australian Accounting Standards Board.[74] JGN further stated that it currently has no obligations for sustainability reporting on business performance of emissions reduction.[75] JGN clarified that most of the work necessary to comply with the new reporting requirements, including the development of internal control procedures and data collection processes, will occur in the second half of 2024.[76] On a high-level and to quantify the cost for the compliance requirement, it grouped the process and activities in 6 categories and explained that due to the complexity of the reporting requirements, the implementation will require two years for the necessary systems and processes: initial set up in the first year, with refinements in the second year of 2025–26.[77]

We observe that the *Treasury Laws Amendment (Financial Market Infrastructure and Other Measures) Act 2024* received royal assent in September 2024. This legislation mandates the reporting as specified within the Exposure Draft SR1 Australian Sustainability Reporting

72 JGN, *2025–30 Access arrangement proposal – Att. 6.2 – Opex step changes justification, June 2024,* pp. iii and 22; IR#013, Q2(a) – Public, pp. 14–15.

73 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, October 2024, p. 24; AER, *Better Resets Handbook*, July 2024, pp. 23 and 26.

74 JGN, *2025–30 Access arrangement proposal – Att. 6.2 – Opex step changes justification, June 2024,* pp. iii and 22; JGN, *Response to Information request IR#013*, Q2(a), 8 October 2024, pp. 14–15.

75 JGN, *2025–30 Access arrangement proposal – Att. 6.2 – Opex step changes justification, June 2024,* p. 23.

76 JGN, *2025–30 Access arrangement proposal – Att. 6.2 – Opex step changes justification, June 2024,* p. 23.

77 JGN, *2025–30 Access arrangement proposal – Att. 6.2 – Opex step changes justification, June 2024,* pp. 23–24.

Standards – Disclosure of Climate-related Financial Information. We have assessed the step change and regulatory obligation in accordance with this legislation.

We are not satisfied that the proposed step change is consistent with our step change guidance,[78] or that the proposed costs are prudent and efficient. Importantly, we consider that these costs are already provided through our base-step-trend forecasting approach. We explain our reasons below.

In terms of step changes, the Better Resets Handbook explains our step change expectations. It explains that *costs arising from new regulatory obligations should represent a major upward step to comply and should not be capable of being managed otherwise under forecast opex through in-built provisions under output, price and productivity growth*.[79] Additionally, our *Expenditure Forecast Assessment Guideline* clarifies that step changes should not double count the cost of increased regulatory burden over time, which forecast productivity growth may already account for. That is, to be approved as a step change, costs associated with new obligations should demonstrably reflect a magnitude in uplift in costs that is above the historic average change in costs for meeting regulatory obligations while simultaneously achieving productivity gains..[80] Further, it also specifies that we will not provide step changes for short-term costs for implementation of efficiency improvements, which are subject to incentive schemes.[81]

Overall, we consider that these obligations largely represent an extension to existing business-as-usual (BAU) practices (e.g. strategic planning, governance, and emissions accounting and reporting). For instance, some notable new requirements, such as climate change modelling and Scope 3 carbon accounting and reporting, essentially represent an extension of comparable core and longstanding BAU processes (e.g. existing emissions reporting or modelling expertise from active energy, demand, financial and asset impact and management forecast modelling). We note our rate of change methodology provides an uplift to BAU activities in our base-step-trend opex forecasting approach.

In terms of the proposed costs, we are not satisfied that these costs are prudent and efficient. Particularly, this includes the 'External support, formal audit and assurance' costs, which represents 67% of the proposed step change.[82] First, we consider JGN has not appropriately separated and forecast only the incremental new costs (e.g. 'formal audit and assurance'). Second, we are not satisfied that JGN has sufficiently justified the ongoing, rather than a one-off, requirement for 'external support'. We also observe that JGN's forecast costs appear higher than those received through quotes. Third, and as suggested by JGN,[83] we are concerned with the level of costs funding efficiency improvements, which are subject to incentive rewards.

---

78 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, October 2024, p. 24; AER, *Better Resets Handbook*, July 2024, pp. 23 and 26.

79 AER, *Better Resets Handbook*, July 2024, p. 26.

80 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution,* October 2024*,* p. 24.

81 AER, *Expenditure Forecast Assessment Guidelines for Electricity Distribution,* October 2024*,* p. 10.

82 JGN, *2025–30 Access arrangement proposal – Att. 6.11M – Climate reporting* model, June 2024.

83 JGN, *2025–30 Access arrangement proposal – Att. 6.2 – Opex step changes justification, June 2024,* pp. 23–24; JGN, *Att. 6.2 – Opex step changes justification, June 2024,* pp. 23.

Consequently, for these reasons, we have not included JGN's proposed emission reporting step change in our alternative estimate of total forecast opex.

6.4.3.4 Emissions measurement – Picarro leak detection services

JGN proposed a $20.8 million step change to acquire 5.75 Picarro leak detection services. We have not included this step change in our alternative estimate, as we are not satisfied that the step change is prudent and efficient.

Table 6.14: Emission measurement – Picarro step change ($million, 2024–25)

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
JGN's proposal	4.2	4.1	4.2	4.2	4.2	20.8
AER alternative estimate	–	–	–	–	–	–
Difference	**–4.2**	**–4.1**	**–4.2**	**–4.2**	**–4.2**	**–20.8**

Source: JGN, *2025–30 Access arrangement proposal – Att. 6.3M – Operating expenditure forecasting model,* June 2024; AER analysis.
Note: Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

JGN submitted that the Picarro advanced mobile leakage detection technology (Picarro) (vehicle with advanced sensors) will help it more accurately detect gas leaks, enable a proactive maintenance approach, and result in greater visibility of its network integrity.[84] It also considered Picarro will allow it to adopt a higher-order greenhouse gas emissions calculation,[85] enabling it to contribute to the achievement of the NSW and Australian governments' emission reduction targets,[86] consistent with the National Gas Objective.[87] JGN selected option 3 (8 cars) of the 3 options assessed,[88] thus proposing an uplift in costs associated with the purchase of an additional 5.75 Picarro units and associated expenses. JGN currently has the costs of 2.25 Picarro units in its base year.[89]

In terms of emissions reduction, Picarro may enable better control of JGN's unaccounted for gas (UAFG), and thus contribute to lowering associated fugitive emissions. Fugitive emissions form a significant portion of JGN's total greenhouse gas footprint.[90] JGN also stated that the current pipeline fugitive emissions reporting accounting method relies on a standardised formula, and that this may be inaccurate and underestimate the true extent of leakages.[91] Using Picarro, JGN therefore plans to engage the Clean Energy Regulator (CER)

---

84 JGN, *2025–30 Access arrangement proposal – Att. 6.2 – Opex step changes justification*, June 2024, p. 19.

85 JGN, *2025–30 Access arrangement proposal – Att. 6.2 – Opex step changes justification*, June 2024, p. 17.

86 JGN, *2025–30 Access arrangement proposal – Att. 6.2 – Opex step changes justification*, June 2024, p. 17; JGN, *Att. 4.1 – Emission reduction program,* June 2024, p. 22.

87 JGN, *2025–30 Access arrangement proposal – Att. 6.2 – Opex step changes justification*, June 2024, p. 17.

88 JGN, *2025–30 Access arrangement proposal – Att. 6.2 – Opex step changes justification*, June 2024, pp. 20–22.

89 JGN, *2025–30 Access arrangement proposal – Att. 6.2 – Opex step changes justification*, June 2024, pp. 20–22.

90 JGN, *2025–30 Access arrangement proposal – Att. 6.2 – Opex step changes justification*, June 2024, p. 16.

91 JGN, *2025–30 Access arrangement proposal – Att. 6.2 – Opex step changes justification*, June 2024, p. 17.

to establish a new method based on the more accurate measurements by Picarro.[92] JGN considers this to also require moving to an annual survey program,[93] as opposed to the current 5-year program, involving completing walking surveys across its 26,000km network.[94]

We assessed the information JGN provided in its initial proposal, including the information provided as part of our information request process.

Overall, we consider it prudent for JGN to pursue improvements to better manage its pipeline network, including its UAFG. However, we are not satisfied that JGN has demonstrated that the proposed uplift to 8 Picarro units is prudent and efficient for emission reduction measurement and reporting purposes. We are instead satisfied that the prudent level is the 3 Picarro units JGN currently has in operation. In terms of the incremental cost, or the 0.75 Picarro units not in its base year, we consider that this uplift is already provided by applying the rate of change in our opex forecasting methodology.

In terms of JGN's reporting concerns, we are not satisfied JGN has provided evidence, nor an indicative timeline, to demonstrate that the CER will adopt the new emission accounting methodology. However, we also consider that should a direct-measurement approach be adopted in the future, a lower inspection requirement, than the proposed annual frequency, is likely to be sufficient.[95] For instance, the United Nations Environment Programme's Oil and Gas Methane Partnership 2.0 reporting framework is currently the only comprehensive, measurement-based international reporting framework for the oil and gas sector. As such, and in the absence of supplied information or discussion to detail an alternate direct-measurement approach, we therefore consider the CER may likely refer or adopt a similar measurement approach. In this regard, we note that both the framework's level 4 and level 5 reporting allow for 'detailed engineering calculations and modelling'. This means that rather than requiring annual direct measurements, this may be completed on a 3 or 5-year cycle. Modelling may be completed for the interim years, including measurements where notable changes occur (e.g. following rectification of leaks). Therefore, we are satisfied that JGN's existing fleet and 3 Picarro units will provide sufficient data and information to transition to a direct-measurement approach, should the CER allow for a change in estimating and reporting emissions in the future.

We expect that realised cost savings associated with the reduced requirement to complete labour-intensive walking surveys,[96] would adequately offset these incremental costs. JGN did not capture these savings in its analysis of costs and benefits.

For the draft decision, and based on the reasons discussed above, we have therefore not included this step change in our alternative estimate of total forecast opex.

---

92 JGN, *2025–30 Access arrangement proposal – Att. 6.2 – Opex step changes justification*, June 2024, p. 17.

93 JGN, *2025–30 Access arrangement proposal – Att. 4.1 – Emission reduction program*, June 2024, p. 23.

94 JGN, *2025–30 Access arrangement proposal – Att. 6.2 – Opex step changes justification*, June 2024, p. 17.

95 JGN, *2025–30 Access arrangement proposal – Att. 4.1 – Emission reduction program,* June 2024, p. 23.

96 JGN, *2025–30 Access arrangement proposal* – Att. 6.2 – *Opex step changes justification*, June 2024, p. 17.

6.4.3.5 Pipeline Integrity Management Program

We have included this step change in our alternative estimate but applied an adjusted forecast of $17.0 million to remove double counting.

JGN proposed a $28.1 million step change for its pipeline integrity management program, stating that the proposed expenditure is driven by safety, continuous supply (the on-going delivery of gas to JGN's customers), and cost effectiveness (e.g. avoiding expensive repairs and large consequential losses due to unplanned failures).[97] Under its pipeline licence, JGN is required to operate and maintain its pipelines in accordance with Australian Standard (AS) 2885.3,[98] consistent with best industry practice.[99] JGN submitted that the core activity of its pipeline integrity management program is In-line inspection (ILI).[100]

JGN stated that it conducted a comprehensive review of the AS2885.3 requirements applying a risk-based asset management approach to develop its forecast pipeline integrity management program. It stated that this review identified the need for a significant increase in preventative measures over the 2025–30 period.[101]

We have reviewed the material submitted by JGN. We also requested and obtained additional information to clarify why JGN expected an increase in its pipeline integrity management activities over the 2025–30 period given that such activities are cyclical.

While we consider it prudent for JGN to comply with its licence requirements by undertaking ILI inspections and subsequent validation digs in accordance with industry practice, our review of JGN's calculations found that JGN overstated the proposed step change amount. In its response to a request for clarification, JGN acknowledged that the proposed step change amount double counts costs already provided for in the 2025–30 period through the final year adjustment amount.[102] Accordingly, we have included this step change in our alternative estimate of total opex but applied a lower step change amount of $17.0 million to remove this double counting.

6.4.3.6 License fees

We have included forecast licence fees in our alternative estimate as a step change because we do not consider they need to be forecast on a category specific basis. This is consistent with our recent determinations.[103]

---

97 JGN, *2025–30 Access arrangement proposal – Att 6.2 – Opex step change justification*, June 2024, p. 25.

98 JGN stated that both the *Pipelines Act 1967 (NSW)* and *Gas Supply Act 1996* (NSW) oblige JGN to meet the requirements of AS2885.3. See: JGN, *2025–30 Access arrangement proposal – Att. 6.2 – Opex step changes justification*, June 2024, p. 25.

99 AS 2885.3 relates to Pipelines – Gas and Liquid Petroleum: Operations and Maintenance that documents Integrity Management Standards. See: JGN, *2025–30 Access arrangement proposal – Att. 6.2 – Opex step changes justification*, June 2024, p. 25.

100 JGN, *2025–30 Access arrangement proposal – Att 6.2 – Opex step change justification*, June 2024, p. 25.

101 JGN, *2025–30 Access arrangement proposal* – Att. 6.2 – *Opex step change justification,* June 2024, p. 25.

102 JGN, *Response to AER information request JGN IR#011 relating to the opex pipeline integrity management program step change*, 27 September 2024, Question 5, p. 19.

103 See, for example, our decision on Energy Safe Victoria levies for AusNet Services: AER, *AusNet 2023–28, Draft Decision, Attachment 6, Operating expenditure*, December 2022, pp. 18–19.

JGN proposed a category specific forecast of $21.3 million for licence fees. These include fees set by IPART, local government taxes, and Energy and Water Ombudsman NSW (EWON) fees. JGN stated that it based the proposed amount on the historical average of fees paid over 2021–24, which it considers is a good proxy for what would be incurred on average over the 2025–30 period for these costs.[104] These levies and fees have in the past been subject to a true-up through our reference tariff variation mechanism because they can vary from year to year and are outside JGN's control. Consequently, they have been forecast on a category specific basis to enable the true-up.

We reviewed JGN's calculations and found that JGN based its forecast on the average of fees paid over 2021–24. We also found that JGN reported the nominal amount of licence fees in it opex model ($21.3 million) – the escalated equivalent of the proposed amount is $24.1 million.

We also sought and obtained additional information from JGN, and signalled our intention to no longer forecast these on a category specific basis, as proposed by JGN. It maintained that licence fees be considered as a category specific forecast and trued-up under the tariff variation formula. It stated that it receives invoices for licence fees components irregularly and as a result, costs can vary from year to year. It stated that it has no control over these costs or the timing of invoices.[105]

Our review of JGN's licence fee data from 2013–14 to 2022–23 indicates each component (pipeline licence fees, authorisation fees, local government taxes and ombudsman fees) does not vary significantly year on year. This is particularly the case when considered in the context of total opex. The costs are relatively minor and do not lead to significant changes in total opex from year to year.

We have also reviewed our 2020–25 JGN decision where we determined licence fees to be a category specific forecast. Licence fees include IPART charges, EWON fees and mains tax. In that decision we included licence fees as a category specific forecast to enable the true-up factor in the tariff variation formula that we approved. However, we now consider these costs are relatively minor and do not change significantly from year to year. In the event they did change significantly, they would likely qualify for a pass through as a tax change event. Providing a true-up in the tariff variation formula effectively funds these costs on a cost-of-service basis. We consider this is inconsistent with the incentive-based framework and that pass through arrangements are sufficient to deal with any significant change in these costs. This is the approach we have taken in recent gas distribution decisions such as for AusNet Gas Services. In that decision for the 2023–28 period we included Energy Safe Victoria (ESV) levies in the ex-ante opex forecast, rather than recovering this expenditure via the tariff variation formula as proposed by AusNet Services.[106]

---

104 JGN, *2025–30 Access arrangement proposal – Att 6.1 – Operating expenditure – 20240628*, June 2024, p. 22.

105 JGN, *Response to Information Request IR#019 Category specific forecast – licence fees*, 3 October 2024, p. 1.

106 AER, *AusNet 2023–28 – Draft Decision – Attachment 6 – Operating Expenditure*, December 2022, pp.18–19.

Consistent with our AusNet Gas Services 2023–28 decision, we have included these costs as a step change. Further, the efficiency carryover mechanism will share forecasting risk between JGN and its network users. As outlined above, we have escalated the average nominal amount proposed by JGN to determine a step change amount of $24.1 million.

6.4.4 Category specific forecasts

JGN's proposal included four expenditure items, or category specific forecasts, which were not forecast using the base-step-trend approach. These were for debt raising costs, UAFG costs, licence fees and safeguard mechanism costs. In addition to these, we have also included a category specific forecast for support for customers experiencing vulnerability, which JGN included as a step change.

We discuss each of these below.

6.4.4.1 Debt raising costs

We have included debt raising costs of $9.5 million in our alternative estimate. This is $0.2 million less than the $9.7 million proposed by JGN.[107]

Table 6.15: Debt raising costs ($million, 2024–25)

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
JGN's proposal	2.0	2.0	2.0	1.9	1.9	9.7
AER alternative estimate	1.9	1.9	1.9	1.9	1.8	9.5
Difference	–0.0	–0.0	–0.0	–0.1	–0.0	–0.2

Source: JGN, *2025–30 Access arrangement proposal - Att. 6.3M – Operating expenditure forecasting model,* June 2024; AER analysis.
Note: Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

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

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

6.4.4.2 Unaccounted for gas costs

We have included forecast UAFG costs of $141.7 million in our alternative estimate. This is $4.1 million lower than JGN's proposal because we have applied mechanical adjustments as set out below.

JGN proposed a category specific forecast of $145.8 million for UAFG and a true-up factor in its tariff variation mechanism to account for differences in gas receipts and the cost of gas to

107 JGN, *2025–30 Access arrangement proposal – Att. 6.3M – Operating expenditure forecasting model,* June 2024.

that assumed in the forecast.[108] JGN maintained the same approach to forecast UAFG that it applied over the 2020–25 access arrangement period.[109]

While we are satisfied that including the UAFG category specific forecast in our alternative estimate would result in a total opex forecast that meets the opex criteria, we are not satisfied that JGN's proposed UAFG amount of $145.8 million would result in a total opex forecast that meets the requirements for forecasts and estimates.[110] We have reviewed the material submitted by JGN, including the proposed approach, inputs, assumptions, and calculations. We have identified a discrepancy between the demand forecast (demand market) that JGN relied on to calculate its forecast of UAFG, and the forecasts reported by its consultant, CORE. We have corrected this discrepancy by relying on CORE forecasts for our alternative estimate, in consultation with JGN.

Table 6.16: Unaccounted for gas costs ($million, 2024–25)

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
JGN's proposal	36.1	32.8	27.8	25.1	24.1	145.8
AER alternative estimate	34.6	31.2	27.0	24.9	24.0	141.7
Difference	**–1.5**	**–1.5**	**–0.8**	**–0.2**	**–0.1**	**–4.1**

Source: JGN, *2025–30 Access arrangement proposal – Att. 6.3M – Operating expenditure forecasting model,* June 2024; AER analysis.

Note: Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

6.4.4.3 Licence fees

As discussed in section 6.4.3.6 we consider licence fees should be recovered via opex rather than through the price control mechanism, or via a true up. Accordingly, we have not included a category specific forecast for licence fees, and instead included these costs as a step change for the 2025–30 period.

6.4.4.4 Safeguard mechanism costs

JGN proposed $10.4 million for the purchase of Australian Carbon Credit Unit (ACCU) offset certificates to comply with the Safeguard Mechanism. We have not included this category specific forecast in our alternative estimate, and instead we have applied a true up approach through the reference tariff variation mechanism. This is consistent with our previous decisions for Safeguard Mechanism costs.[111]

---

108 JGN, *2025–30 Access arrangement proposal – Att 6.1 - Operating expenditure – 20240628*, June 2024, p. 21.

109 JGN, *2025–30 Access arrangement proposal – Att 6.1 - Operating expenditure – 20240628*, June 2024, p. 21.

110 NGR, r. 74(2).

111 AER, *AusNet 2023–28 – Final decision – Attachment 10 Reference tariff variation mechanism,* June 2023, p. 4; AER, *AGN – Final decision – Attachment 10 Reference tariff variation mechanism,* June 2023, p. 4; AER, MGN *2023–28 – Final decision – Attachment 10 Reference tariff variation mechanism,* June 2023, p. 4.

Table 6.17: Safeguard Mechanism costs ($million, 2024–25)

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
JGN's proposal	2.2	2.3	2.1	2.0	1.9	10.4
AER alternative estimate	–	–	–	–	–	–
Difference	**–2.2**	**–2.3**	**–2.1**	**–2.0**	**–1.9**	**–10.4**

Source: JGN, *2025–30 Access arrangement proposal – Att. 6.3M – Operating expenditure forecasting model,* June 2024; AER analysis.
Note: Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

JGN submitted that the Safeguard Mechanism is a new obligation, with the compliance costs beyond its control.[112] JGN considered that including these costs as a category specific forecast aligns with rule 91(1) of the NGR, and ensures that it incurs costs as a prudent, efficient service provider, adhering to accepted good industry practice and the National Gas Objective.[113] In response to an information request, JGN also explained that its emissions projections remain uncertain, and are subject to any future baseline variations,[114] including that forecast ACCU costs themselves remain highly uncertain.[115] In the context of uncertainty, JGN also stated it will use the tariff variation mechanism to ensure that only costs incurred are recovered, with any benefits received to be passed on to customers.[116]

The Safeguard Mechanism is the Australian Government's policy for reducing emissions at Australia's largest industrial facilities, with the legislative framework set out in the *National Greenhouse and Energy Reporting Act 2007* (Cth). It ensures that these covered facilities achieve a proportional share of Australia's emission reduction targets.[117] The Clean Energy Regulator (CER) administers the Safeguard Mechanism, including establishing a facility's annual target on the quantity of allowed emissions, known as baselines.[118] These baselines are currently set to reduce by 4.9% annually until 2030.[119] To meet baseline targets, facilities may either directly reduce their relevant emissions, or purchase greenhouse gas offset certificates, including ACCUs.[120]

We assessed the information provided by JGN in its proposal, including information received through information requests, to justify the proposed costs.

---

112 JGN, *2025–30 Access arrangement proposal – Att 6.1 – Operating expenditure*, June 2024, p. 22.

113 JGN, *2025–30 Access arrangement proposal – Att 6.1 – Operating expenditure, June 2024*, pp. 22–23.

114 JGN, *Response to information request IR#005, Q2.2(b),* 23 August 2024, p. 5.

115 JGN, *2025–30 Access arrangement proposal – Att 6.1 – Operating expenditure, June 2024*, p. 22.

116 JGN, *2025–30 Access arrangement proposal – Att 6.1 – Operating expenditure, June 2024*, p. 23.

117 Australian Government – Department of Climate Change, Energy the Environment and Water, *Safeguard Mechanism* Reform, May 2024, p. 1.

118 Australian Government – Department of Climate Change, Energy the Environment and Water, *Safeguard Mechanism* Reform, May 2024, p. 1.

119 Australian Government – Department of Climate Change, Energy the Environment and Water, *Safeguard Mechanism* Reform, May 2024, p. 1.

120 Australian Government – Department of Climate Change, Energy the Environment and Water, *Safeguard Mechanism* Reform, May 2024, p. 1.

We are satisfied that JGN has a new compliance obligation arising from the Safeguard Mechanism. We are also conscious of the limited currently available processes and suitable low emission technologies that would allow JGN to achieve emission reduction through means other than offsets. We therefore consider it prudent for JGN to meet its Safeguard Mechanism compliance obligations through the purchase of greenhouse gas emissions offset certificates.

However, we consider the Safeguard Mechanism costs should not be recovered through opex or as a category specific forecast, but instead recovered through a reference tariff variation mechanism for gas transportation (haulage) services. This approach is consistent with the treatment of Safeguard Mechanism costs in our previous decisions.[121] We consider maintaining consistency across network services providers to be the preferrable approach. For the avoidance of doubt, this means that Safeguard Mechanism costs will be managed through amendments to the tariff control formulae.

Consistent with our previous decisions, we expect JGN not to include costs associated with penalties for failing to meet acquittal obligations. We consider this risk is more appropriately borne by JGN's shareholders, who should therefore be responsible for any penalties incurred for noncompliance. Further, we also expect that should JGN achieve credits by emitting less than its baseline in any year of the 2025–30 period, and sell those credits, the revenue earned is returned to customers via the tariff control formula Safeguard Mechanism factor. That is, the Safeguard Mechanism factor will be symmetrical. It will recover eligible costs from customers but will also return value to customers should JGN achieve emission levels below its baseline.

The control mechanism approach is an ex-post approach, where JGN would:

- incur the Safeguard Mechanism costs in year 1 (2025−26)
- report estimated Safeguard Mechanism costs to us ahead of year 2 via annual pricing proposals, and incorporate the costs in haulage reference tariffs for year 2 (2026−27)
- report the full year 1 actual emissions costs ahead of year 3 (2027−28) via annual pricing proposals, and true up year 3 haulage tariffs to account for the actual amounts if necessary.

To administer this approach, we require invoices from JGN as evidence of costs being incurred. We will reconcile costs reported to us through this approach using regulatory information notice data (which is subject to audit assurance). We also require JGN to submit receipts for any revenues earned from selling credits created by achieve emission levels below its annual baseline.

For our alternative estimate for the draft decision, we have not included JGN's Safeguard Mechanism category specific forecast costs.

[121] AER, *AusNet 2023–28 – Final decision – Attachment 10 Reference tariff variation mechanism,* June 2023, p. 4; AER, *AGN – Final decision – Attachment 10 Reference tariff variation mechanism,* June 2023, p. 4; AER, MGN *2023–28 – Final decision – Attachment 10 Reference tariff variation mechanism,* June 2023, p. 4.

6.4.4.5 Abolishments opex

As set out in Attachment 9, our final decision is to socialise the bulk of small customer abolishment costs across transportation reference service tariffs, and establish a discounted stand-alone ancillary reference service tariff, to ensure the safe operation of the network. Specifically, we decided to cap the small customer connection abolishment ancillary reference service at $250 and socialise the balance across transportation reference service tariffs via an ex-ante opex forecast. This forecast will be subject to an annual true-up via the control mechanism. This contrasts with JGN's proposal that the cost of the abolishment service be recovered from the requesting customer.

In coming to our draft decision on the ex-ante opex forecast, we investigated the forecast transportation reference service customer and abolishment numbers provided by JGN in its proposal.[122] Forecast customer numbers provide information about customers who are forecast to remain on the network and those who are forecast to leave the network. Following our investigation, we have adjusted JGN's forecast abolishment volumes to account for:

- our view on the forecast number of customers
- the impact a lower abolishment charge will have on the number of customers that will request an abolishment rather than a disconnection.

We consider that accounting for these factors, and applying the associated adjustments to JGN's abolishment forecast, results in the best estimate of the abolishment volumes over the next access arrangement period. This estimate is higher than the abolishment forecast JGN proposed.

We have used these forecasts, and the abolishment costs to be recovered via the transportation reference service tariffs, to determine the additional opex required to be included in our draft decision to enable JGN to recover its costs for performing abolishment services. On this basis we have included an opex forecast of $66.4 million for abolishment service costs in our draft decision opex, as a category specific forecast.

Below we set out JGN's abolishments forecast, along with the further information we have considered in our review of these forecasts. We then explain our view on the appropriate abolishments forecast, which as noted above is higher than JGN's forecast, the reasons for this and the associated opex forecast that we have included in this draft decision.

JGN's abolishments forecast

In its proposal, JGN proposed a 'user-pays' approach to the recovery of costs associated with its gas connection abolishment service.[123] This means abolishment costs would be fully recovered via ancillary reference service charges. Because JGN proposed a 'user-pays' approach to recovery of abolishment costs in its proposal, it did not include any abolishment costs within its transportation reference service opex forecast.

---

122 JGN, *2025–30 Access arrangement proposal – RIN – Att 3 – Workbook 1 – Forecast*, June 2024.

123 JGN, *Jemena Gas Networks 2025 Plan*, June 2024, pp. 138–139.

In JGN's proposal, it provided residential customer number forecasts for the next access arrangement period.[124] This included forecasts of the number of disconnections, abolishments, reconnections and new connections (see Table 6.18).

Table 6.18 JGN's forecast of the number of connections and disconnections

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
Disconnections	18,404	20,367	23,633	30,870	44,970	**138,244**
Abolishments	5,768	7,950	8,433	9,953	12,889	**44,993**
New connections	21,551	19,685	17,331	13,707	10,612	**82,886**
Reconnections	13,524	13,048	12,654	12,208	11,376	**62,811**

Source: JGN, *2025–30 Access arrangement proposal – RIN – Att 3 – Workbook 1 – Forecast*, June 2024.

Information we have taken into account to assess JGN's abolishment forecast

Each of the gas distributors subject to full economic regulation submit monthly disconnection data to us each quarter. This data includes the number of:

- customers
- abolishments
- disconnections
- new connections (no previous supply)
- reconnections (previous supply at the connection point).

The data commences in July 2022 and at the time of writing goes through to June 2024. The data for JGN, shows that abolishment service volumes, as a percentage of total customers, has remained consistently low at only 0.02% over the period.[125]

JGN is forecasting abolishments to increase from 4,055 in 2023–24 to 12,889 in 2029–30. Over the same period, JGN is forecasting disconnections to increase from 17,381 to 44,970 and reconnections to fall from 14,073 to 11,376.[126] The widening gap between disconnections and reconnections implies that JGN expects many customers wishing to leave the gas network will request a disconnection service rather than an abolishment service under its proposal.

Our review of forecast customer numbers and abolishments

We engaged ACIL Allen to review JGN's proposed customer number forecasts. This included reviewing the number of customers likely to leave the network. We discuss this review in more detail in Attachment 5. While we and ACIL Allen are satisfied that JGN's forecast of the number of new connections is reasonable, we considered fewer customers

124 JGN, *2025–30 Access arrangement proposal – RIN – Att 3 – Workbook 1 – Forecast*, June 2024.

125 AER, *Gas quarterly disconnection reporting*, 29 October 2024.

126 JGN, *2025–30 Access arrangement proposal – Reset RIN, Workbook 1, Forecast, Sheet S1 Customer numbers by type*, June 2024.

are likely to leave the network than JGN has forecast. Our reasons for reaching this view are set out in Attachment 5.

In forecasting the number of customers that will leave the network, ACIL Allen did not consider the service those customers would request. That is, it did not separately forecast the number of disconnections and abolishments.

When a customer chooses to leave the gas network it can do so by requesting either a disconnection or an abolishment. If the customer requests a disconnection the service pipe and meter remains in place, allowing the customer to easily reconnect in the future if they choose to. If the customer requests an abolishment JGN removes the meter and disconnects and caps the service pipe at the main.

We have considered if some customers are likely to leave the network via disconnection instead of an abolishment because they see 'option value' in retaining a gas connection. This 'option value' may be perceived to protect future resale value, as some new purchasers may place a premium on having a gas connection (even if the current owner does not). Similarly for commercial or rented residential premises, where the usage could change considerably with a change in tenants, maintaining a gas option may be seen as valuable for future tenants. 'Option value' customers are likely to behave differently than customers who choose not to abolish their gas connection because of any relative price difference between the two different services. 'Option value' customers are likely to choose not to abolish their connection under a socialised approach where the two services are priced similarly and will only request an abolishment if they no longer perceive sufficient value in retaining a dormant gas connection.

When questioned on this, JGN did not express a view on the proportion of customers that would request an abolishment rather than a disconnection. Given JGN did not express a view on this, we have assumed that 100% of customers choosing to leave the network will request an abolishment as a placeholder for this draft decision. We expect that in its revised proposal JGN will express a view on the proportion of customer leaving the network who would choose an abolishment if the cost of the two services is similar. JGN should support its view with reasons.

6.4.4.6 Our abolishment forecast and the associated opex forecast

For the reasons discussed above, we have assumed that all the customers forecast by ACIL Allen to leave the gas network will request an abolishment. Consequently, for this draft decision we have forecast 32,747 more abolishments than forecast by JGN over the 2023–28 period, as shown in Table 6.19.

Table 6.19 Draft decision forecast abolishment volumes

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
JGN's forecast	5,768	7,950	8,433	9,953	12,889	**44,993**
AER's draft decision	6,183	8,166	14,112	20,531	28,748	**77,740**
Difference	415	216	5,679	10,578	15,859	**32,747**

Source: AER analysis; JGN, *2025–30 Access arrangement proposal – RIN – Att 3 – Workbook 1 – Forecast*, June 2024.

Note: Numbers in the table may not sum to total due to rounding.

We have used our forecast of abolishment volumes, along with the abolishment costs to be socialised via haulage reference service opex ($854, $2024–25) to determine the abolishments opex forecast. We discuss the basis of the abolishment costs to be socialised in Attachment 9.

Our draft decision forecast opex for abolishments, totalling $66.4 million, is shown in Table 6.20.

Table 6.20 Draft decision forecast abolishments opex ($million, 2024–25)

2025–26	2026–27	2027–28	2028–29	2029–30	Total
5.3	7.0	12.1	17.5	24.6	**66.4**

Source: AER Analysis.
Note: Numbers in the table may not sum to total due to rounding.

We have included this abolishment opex forecast as a category specific forecast because it does not rely on actual costs in the base year to be forecast. It also enables these costs to be separated from the other more business-as-usual costs in the opex forecasts, which is required for the operation of a true-up mechanism. In this regard, we note there is significant uncertainty associated with this forecast and as a result, we have included a true-up in the tariff control mechanism for abolishment costs. This true-up is set out in more detail in Attachment 10.

6.5 Revisions

We require the following revisions to make the access arrangement proposal acceptable as set out in Table 6.21.

Table 6.21 Opex revisions

Revision	Amendment
Revision 6.1	Make all necessary amendments to reflect our draft decision on the proposed opex forecast for the 2025–30 access arrangement period, as set out in section 6.1.

Glossary

Term	Definition
AER	Australian Energy Regulator
Ancillary RS	Ancillary Reference Service
capex	capital expenditure
ECM	efficiency carryover mechanism
Handbook	The Better Resets Handbook
ICT	Information and communication technologies
JGN	Jemena Gas Networks
NGL	National Gas Law
NSW	New South Wales
NGO	National Gas Objectives
NGR	National Gas Rules
opex	operating expenditure
SaaS	Software as a Service
Transportation RS	Transportation Reference Service
UAFG	unaccounted for gas