DRAFT DECISION
Jemena Gas Networks (NSW) Ltd
Access Arrangement

2020 to 2025

Attachment 6
Operating expenditure

November 2019

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne Vic 3001

Tel: 1300 585 165
Email: AERInquiry@aer.gov.au

AER reference: 63819

Note

This attachment forms part of the AER's draft decision on the access arrangement that will apply to Jemena Gas Networks (NSW) Ltd ('JGN') for the 2020–2025 access arrangement period. It should be read with all other parts of the draft decision.

The draft decision includes the following documents:

Overview

Attachment 1 – Services covered by the access arrangement

Attachment 2 – Capital base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency carryover mechanism

Attachment 9 – Reference tariff setting

Attachment 10 – Reference tariff variation mechanism

Attachment 11 – Non-tariff components

Attachment 12 – Demand

Attachment 13 – Capital expenditure sharing scheme

Contents

Shortened forms

Shortened form	Extended form
AER	Australian Energy Regulator
Capex	Capital expenditure
CAM	Cost allocation methodology
CESS	Capital expenditure sharing scheme
CCP/CCP19	Consumer Challenge Panel, sub-panel 19
CPI	Consumer price index
EBSS	Efficiency benefit sharing scheme
ECM	Efficiency carryover mechanism
EWON	Energy & Water Ombudsman NSW
IPART	Independent Pricing & Regulatory Tribunal
JEN	Jemena Electricity Networks
JGN	Jemena Gas Networks (NSW) Ltd
NER	National Electricity Rules
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
Opex	Operating expenditure
PTRM	Post-tax revenue model
RBA	Reserve Bank of Australia
RIN	Regulatory Information Notice
RFM	Roll forward model
RPP	Revenue and pricing principles
TAB	Tax asset base
UAG	Unaccounted for gas
WACC	Weighted average cost of capital
WPI	Wage price index

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 JGN's proposed opex forecast for the 2020–25 access arrangement period.

6.1 Draft decision

Our draft decision is not to accept JGN's amended proposal for a total opex forecast of $1120.5 million ($2019–20), including debt raising costs, for the 2020–25 access arrangement period, as submitted to us on 8 October 2019.[1] JGN's 2020–25 proposal initially included forecast total opex of $1045.9 million ($2019–20), including debt raising costs.[2] We are not satisfied JGN's forecast opex meets the opex criteria[3] and the requirements for forecasts and estimates.[4]

In this draft decision, we consider that our alternative estimate of total opex of $1096.6 million ($2019–20), including debt raising costs, for the 2020–25 period meets the opex criteria, subject to it being updated to incorporate the:

- outcome of our review of the additional information we request JGN include in its revised proposal regarding its demand forecasts (see Attachment 12 of this draft decision)
- most up-to-date cost of replacement gas for forecasting the unaccounted for gas (UAG) allowance, which we request JGN include in its revised proposal (see section 6.4.5.3).

Our alternative estimate of total opex for the 2020–25 period is $23.8 million ($2019–20), or 2.1 per cent, lower than JGN's amended opex forecast of $1120.5 million ($2019–20), including debt raising costs.[5] We set out JGN's amended opex forecast and our draft decision alternative estimate of total opex in Table 6.1.

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1 JGN, *Response to AER information request 44*, 8 October 2019.

2 JGN, *Jemena Gas Networks 2020 Plan*, June 2019, p. 72.

3 NGR, r. 91.

4 NGR, r. 74.

5 JGN, *Response to AER information request 44 – Opex Model*, 8 October 2019.

Table 6.1 AER's alternative estimate compared to JGN's amended opex proposal for the 2020–25 access arrangement period ($ million, 2019–20)

	JGN's amended proposal[6]	AER's alternative estimate	Difference
Based on reported opex in 2017–18	923.5	915.4	–8.1
Base year adjustments	84.2	84.2	0.0
2017–18 to 2019–20 increment	21.3	21.1	–0.2
Output growth	40.9	38.0	–2.9
Price growth	15.5	6.1	–9.4
Productivity growth	–19.5	–19.3	0.2
Step changes	–0.7	–0.7	0.0
Category specific forecasts	46.0	46.3	0.2
Total opex (excluding debt raising costs)	**1111.2**	**1091.0**	**–20.2**
Debt raising costs	9.3	5.6	–3.7
Total opex (including debt raising costs)	**1120.5**	**1096.6**	**–23.8**

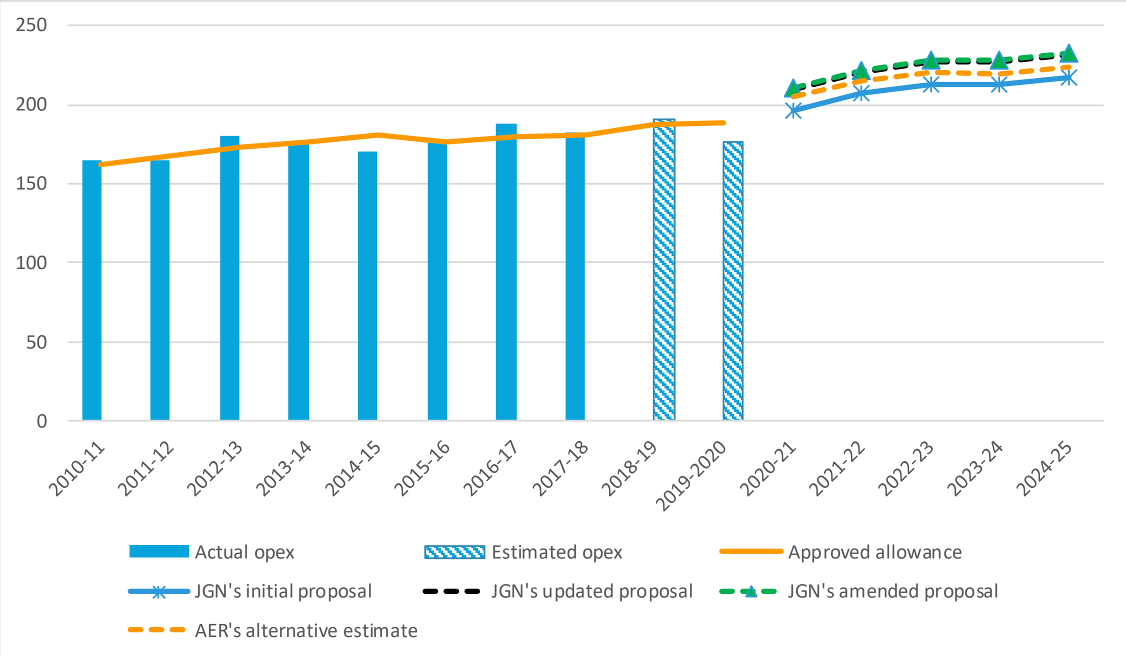
Source: AER analysis; JGN, *Response to AER Information request 44 – Opex Model,* 8 October 2019.

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

Figure 6.1 compares the opex forecast we approve in this draft decision to JGN's proposal, the forecasts we approved for 2010–20 and JGN's actual opex in that period.

6 As submitted by JGN on 8 October 2019.

Figure 6.1 AER's draft decision compared to JGN's past and proposed opex ($ million, 2019–20)



Source: JGN, *Proposed reset RIN*, 30 June 2019; AER, AER Final Decision – JGN NSW GAAR 2015–20 – Revenue forecast model – RFM PTRM, June 2015; AER, JGN PTRM – after appeal, June 2011; JGN, *Response to AER Information request 44 – Opex Model,* 8 October 2019; JGN, *Response to AER Information request 21 – Opex Model,* 2 September 2019; AER analysis.

Note: Includes debt raising costs and unaccounted for gas.

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

- We have used a more recent inflation forecast from the Reserve Bank of Australia (RBA).[7]
- We have forecast a lower input price growth rate compared to that proposed by JGN. We have forecast labour price growth using only Deloitte Access Economics' (Deloitte) forecasts.[8] This is a change to our previous approach of averaging the forecasts from Deloitte and the business' consultant (generally BIS Oxford Economics). It reflects our analysis that over the period 2007 to 2018, Deloitte's real Wage Price Index (WPI) growth forecasts have been more accurate.
- We have forecast lower output growth. We have updated our forecasts of customer numbers and mains length to reflect our draft decision on JGN's forecasts of capex and demand. We discuss capex and demand forecasts in Attachments 5 and 12 of this draft decision, respectively.

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[7] RBA, *Statement on Monetary Policy—Appendix: Forecast*, August 2019.

[8] Deloitte Access Economics, *Labour Price Growth Forecasts Prepared for the AER*, 24 June 2019.

6.2 JGN's proposal

JGN used a 'base–step–trend' approach to forecast opex for the 2020–25 period, consistent with our preferred approach. JGN submitted its initial opex proposal to us on 28 June 2019. JGN amended its initial opex proposal on 2 September 2019 and, again, on 8 October 2019. We discuss these amendments further in section 6.4.

In its amended proposal, as submitted on 8 October 2019, JGN:

- used estimated opex in 2017–18 as the basis for forecasting its opex over the 2020–25 period. If no other adjustments were made, this would lead to a base opex of $923.5 million ($2019–20).
- then adjusted its base opex by:
    - removing category specific forecasts of UAG costs and government levies. This reduced its opex forecast by $135.7 million ($2019–20).
    - applying the approach in the *Expenditure forecast assessment guideline* (the Guideline) to calculate the 2018–19 to 2019–20 opex increment (to arrive at the starting point for its forecast).[9] This reduced its opex forecast by $21.3 million ($2019–20).
    - adding a forecast of corporate overhead costs to reflect its proposal to expense, instead of capitalise, this cost category in the 2020–25 period as it adopts its new cost allocation methodology from 1 January 2021. This increased its opex forecast by $84.2 million ($2019–20).
- applied its overall rate of change forecast to its adjusted base opex, increasing it by $36.9 million ($2019–20). JGN forecast output growth of $40.9 million ($2019–20), input price growth of $15.5 million ($2019–20) and productivity growth of –$19.5 million ($2019–20).
- proposed two step changes that decreased its opex forecast by a total of $0.7 million ($2019–20). This included:
    - a negative step change of $8.4 million ($2019–20) to account for the six months in the 2020–25 period in which JGN would not expense its corporate overheads, as its new cost allocation methodology only comes into effect from 1 January 2021. This step change relates to JGN's proposed base opex adjustment in relation to corporate overhead costs described above.
    - a positive step change of $7.7 million ($2019–20) for expensing pigging and inspection costs.

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

- JGN proposed three opex category specific forecasts for UAG costs ($157.5 million), government levies ($24.2 million) and debt raising costs ($9.3 million). This increased its opex forecast by $191.0 million ($2019–20).

This resulted in JGN proposing an amended total opex forecast of $1120.5 million ($2019–20) for the 2020–25 period (see Table 6.2),[10] which is 23 per cent higher than JGN's actual and estimated opex for the 2015–20 period.

Table 6.2 JGN's proposed opex for the 2020–25 access arrangement period ($ million, 2019–20)

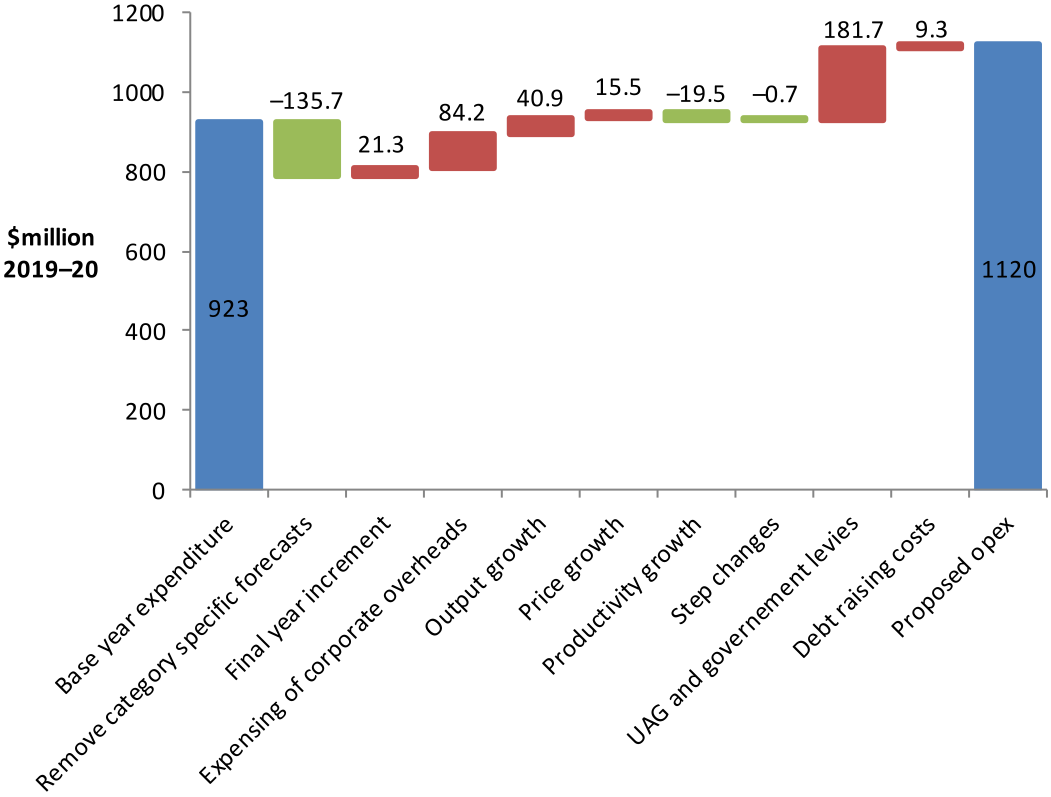
	2020–21	2021– 22	2022–23	2023–24	2024–25	Total
Total opex, excluding debt raising costs	208.7	220.0	225.9	226.2	230.3	**1111.2**
Debt raising costs	1.8	1.8	1.9	1.9	1.9	**9.3**
Total opex, including debt raising costs	210.6	221.9	227.8	228.1	232.1	**1120.5**

Source: JGN, *Response to AER Information request 44 – Opex Model*, 8 October 2019

Figure 6.2 shows the different elements that make up JGN's amended opex forecast for the 2020–25 period.

[10] JGN, *Response to AER Information request 44 – Opex Model*, 8 October 2019; includes debt raising costs.

Figure 6.2 JGN's amended opex forecast for the 2020–25 access arrangement period ($million, 2019–20)



Source: JGN, *Response to AER Information request 44 – Opex Model*, 8 October 2019; AER analysis.

6.2.1 Stakeholder views

We received submissions from nine stakeholders on JGN's 2020–25 proposal, a number of which raised issues on opex. At a high level, the submissions broadly supported JGN's opex proposal. However, some of these submissions stated that we should closely scrutinise the proposed expensing of corporate overheads and UAG increase.

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

Table 6.3 Submissions on JGN's 2020–25 opex proposal

Stakeholder	Issue	Description
Energy Consumers	Total opex	ECA asked that the AER *'explore the reasoning for the increase in the level of opex per dwelling since 2015–20'.*[11]

[11] ECA, *Submission on JGN 2020–25 AA Proposal – Cover Letter*, August 2019, p. 5.

Stakeholder	Issue	Description
Australia (ECA)		
Consumer Challenge Panel (CCP19), ECA, Origin	Base opex (transformation costs)	CCP19 can see a reasonable basis for the case that reclassifying corporate overheads and pigging costs, as opex is likely to deliver long-term benefits to consumers.[12] ECA sought to clarify how transformation program savings have been taken into account,[13] suggesting that it is not clear how these savings have been taken into account in the setting of the base year opex.[14] ECA sought to clarify what the longer-term impact of capitalised overheads will be.[15] Origin's submission discussed the transformation program, stating, *'Origin seeks to understand the business-wide impacts and service quality implications of the program and confirmation these have been appropriately considered in formulating the program'*.[16] In reference to the corporate overheads reclassification, Origin stated that *'The expensing of corporate overheads appears contradictory to the principles of cost allocation and… alignment with accounting practice is not a sufficient rational for the proposed treatment'.* Origin does not accept the proposed expensing of corporate overheads and encourages the AER to review this proposal.[17]
ECA, AGL, Origin	Base opex (cost allocation – classification opex versus capex)	ECA's Cover Letter asks that the AER *'seek more information to explain the Cost Allocation Methodology changes that are proposed'*.[18] AGL *'consider that it is reasonable that costs, such as corporate costs and intelligent pigging costs are treated appropriately as either operating costs (expensed) or capital expenditure (capitalised) depending on whether the costs continue to have benefits in future years.'*[19] Origin *'seek assurance that capex-opex trade-offs have been appropriately considered in developing the capex (and opex) forecasts. Origin also seeks further confirmation that savings in forecast capex in the 2020–25 period will not lead to increased expenditure in future periods (e.g. on reactive maintenance).'*[20] Origin expressed its concern about the *'opex and capex investment incentives where the network continues to be serviced by a range of assets with substantial remaining technical lives, but that no longer earn a return for JGN.'*[21]
AGL, CCP19, ECA, EnergyAustralia, Origin, Public Interest Advocacy	Rate of change	ECA submitted that "the rate of change is consistent with regulatory precedent."[22] EnergyAustralia observed that there is scope to further challenge JGN to deliver controllable efficiency gains and deliver sustained price reductions for customers. In particular, EnergyAustralia noted that productivity growth would

12 CCP19, *Submission on JGN 2020–25 AA Proposal,* August 2019, pp. 24–26.
13 ECA, *Submission on JGN 2020–25 AA Proposal – Cover Letter*, August 2019, p. 17.
14 ECA, *Submission on JGN 2020–25 AA Proposal – Attachment*, August 2019, p. 12.
15 ECA, *Submission on JGN 2020–25 AA Proposal – Attachment*, August 2019, p. 20.
16 Origin, *Submission on JGN 2020–25 AA Proposal*, August 2019, p. 6.
17 Origin, *Submission on JGN 2020–25 AA Proposal*, August 2019, p. 7.
18 ECA, *Submission on JGN 2020–25 AA Proposal – Cover Letter*, August 2019, p. 5.; ECA, *Submission on JGN 2020–25 AA Proposal – Attachment*, August 2019, p. 22.
19 AGL, *Submission on JGN 2020–25 AA Proposal,* August 2019, p. 3.
20 Origin, *Submission on JGN 2020–25 AA Proposal*, August 2019, p. 5.
21 Origin, *Submission on JGN 2020–25 AA Proposal*, August 2019, p. 2.
22 ECA, *Submission on JGN 2020–25 AA Proposal – Cover letter*, August 2019, p. 17.

Stakeholder	Issue	Description
Centre (PIAC)		avoid $59 million of opex over five years, but that opex will increase on average by 2 to 3 per cent annually over the period.[23] Origin consider JGN's approach to forecasting price changes of taking the average between the DAE and BIS forecasts to be acceptable.[24] Various stakeholders have supported JGN's proposed productivity growth of 0.74 per cent per annum including CCP19,[25] ECA,[26] Origin,[27] and PIAC.[28]
CCP19, ECA, Origin	Step change	CCP19 submitted that it sees a reasonable basis for the case that reclassifying corporate overheads and pigging costs, as opex is likely to deliver long-term benefits to consumers.[29] ECA also expressed that no step changes being proposed is a positive.[30] In reference to pigging costs, *'Origin consider that JGN have failed to provide an adequate rationale to support the proposed expensing of these costs and are concerned at the ongoing inconsistency in allocation applied by JGN'*.[31]
CCP19	Marketing opex	CCP19 suggested, *'the AER should consider whether it is prudent use of opex to encourage new customers to connect to the gas network.'*[32]
AGL	Efficiency Carryover mechanism	AGL claim that the efficiency carryover mechanism *'appears to be incongruous.'*[33]

6.3 Assessment approach

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

> "Operating expenditure must be 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."[34]

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

23 EnergyAustralia, *Submission on JGN 2020–25 AA Proposal – Cover Letter/Attachment A*, August 2019, pp. 6–7.
24 Origin, *Submission on JGN 2020–25 AA Proposal*, August 2019, p. 6.
25 CCP19, *Submission on JGN 2020–25 AA Proposal,* August 2019, p. 26.
26 ECA, *Submission on JGN 2020–25 AA Proposal – Cover Letter*, August 2019, p. 10; ECA, *Submission on JGN 2020–25 AA Proposal – Attachment*, August 2019, p. 12.
27 Origin, *Submission on JGN 2020–25 AA Proposal*, August 2019, p. 5.
28 PIAC, *Submission on JGN 2020–25 AA Proposal*, August 2019, pp. 7–8.
29 CCP19, *Submission on JGN 2020–25 AA Proposal,* August 2019, pp. 24–26.
30 ECA, *Submission on JGN 2020–25 AA Proposal – Cover Letter*, August 2019, p. 17.
31 Origin, *Submission on JGN 2020–25 AA Proposal*, August 2019, p. 7.
32 CCP19, *Submission on JGN 2020–25 AA Proposal,* August 2019, p. 28.
33 AGL, *Submission on JGN 2020–25 AA Proposal,* August 2019, p. 4.
34 NGR, rr. 91 and 40(2).

> "A forecast or estimate must be arrived at on a reasonable basis and must represent the best forecast or estimate possible in the circumstances."[35]

We use a form of incentive based regulation to assess the business' forecast opex over the access arrangement period at a total level. To do so, we develop an alternative estimate of total opex using a 'top-down' forecasting method, known as the 'base–step–trend' approach.[36]

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

In making this decision, we take into account the reasons for the difference between our alternative estimate and the business' forecast, and the materiality of that difference. We also take into consideration the interrelationships between the opex forecast and other constituent components of our decision, such that our decision is likely to contribute to the achievement of the National Gas Objective (NGO).[37]

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.[38] A key feature of the regulatory framework is that it is based on incentivising networks to be as efficient as possible. We apply incentive-based regulation across the energy networks we regulate, including gas networks. More specifically for opex, we rely on the efficiency incentives created by both ex ante revenue regulation (where an opex allowance is granted over a multi-year regulatory period) and the efficiency carryover mechanism (ECM).[39]

The incentive-based regulatory framework partially overcomes the information asymmetries between the regulated businesses and us.[40] It is intended to align the commercial goals of the network businesses to the objectives of the regulatory regime—especially the long term interests of consumers (the NGO).

Incentive regulation aligns these goals by encouraging regulated businesses to reduce costs below our forecast, in order for them to make higher profits, and 'reveal' their

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35 NGR, r. 74(2).

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

37 NGL, s. 28(1).

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

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

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

costs in doing so. The information revealed by the businesses allows us to develop better expenditure forecasts over time. Revealed opex reflects the efficiency gains made by a business over time. As a network business becomes more efficient, this translates to lower forecasts of opex in future regulatory periods, which means consumers also receive the benefits of the efficiency gains made by the business. Incentive regulation therefore aligns the business' commercial interests with consumer interests.

The Productivity Commission explains:

> "Under incentive regulation, the regulator forecasts efficient aggregate costs over the upcoming regulatory period (of usually five years), which it uses to set a revenue allowance for that period. The business makes higher profits if it reduces costs below those forecast by the regulator. In doing so, the business reveals the efficient costs of delivering the service, which would then influence the regulator's determination in the next period. Accordingly, incentive regulation encourages efficiency while reducing the risks that networks use their monopoly positions to set unreasonably high prices."[41]

Incentive regulation is designed to leave the day-to-day decisions to the network businesses.[42] It allows the network businesses the flexibility to manage their assets and labour as they see fit to comply with the opex criteria[43] and achieve the NGO.[44]

Our general approach is to assess whether opex, in aggregate, is sufficient to satisfy the opex criteria over the access arrangement period, rather than to assess individual opex projects or programs. To do so, we develop an alternative estimate of total opex using the 'base–step–trend' forecasting approach (section 6.3.2). This is generally a 'top-down' approach, but there may be circumstances where we need to use 'bottom-up' analysis, particularly in relation to our base opex assessment and for step changes.[45]

6.3.2 Building an alternative estimate of total forecast opex

As a comparison tool to assess a business' opex forecast, we develop an alternative estimate of the business' total opex requirements in the forecast period, using the base–step–trend forecasting approach. We apply the forecasting and estimate requirements under the NGR.[46]

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

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

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

43 NGR, rr. 91 and 40(2).

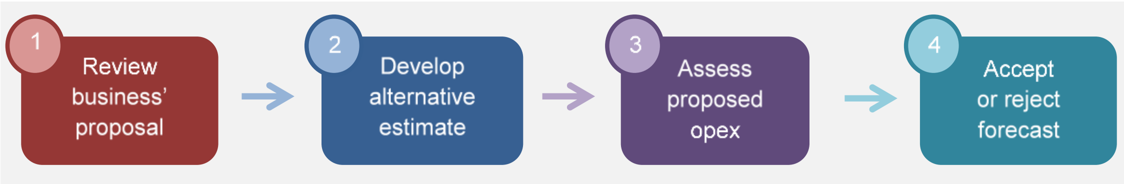
44 NGL, s. 28(1).

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

46 NGR, r. 74(2).

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

Figure 6.3 AER’s opex assessment approach



1. Review business’ proposal

We review the business’ proposal and identify the key drivers.

2. Develop alternative estimate

Base: We use the business’ opex in a recent year as a starting point (revealed opex). We assess the revealed opex (e.g. through benchmarking) to test whether it is efficient. If we find it to be efficient, we accept it. If we find it to be materially inefficient we may make an efficiency adjustment.

Trend: We trend base opex forward by applying a forecast ‘rate of change’ to account for growth in input prices, output and productivity.

Step: We add or subtract any step changes for costs not compensated by base opex and the rate of change (i.e. costs associated with regulatory obligation changes or capex/opex substitutions).

Other: We include a ‘category specific forecast’ for any opex component that we consider necessary to be forecast separately.

3. Assess proposed opex

We contrast our alternative estimate with the business’ opex proposal. We identify all drivers of differences between our alternative estimate and the business’ opex forecast. We consider each driver of difference between the two estimates and go back and adjust our alternative estimate if we consider it necessary.

4. Accept or reject forecast

We use our alternative estimate to test whether we are satisfied the business’ opex forecast is 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 (opex criteria). We accept the proposal if we are satisfied.

If we are not satisfied the business’ opex forecast reasonably reflects the opex criteria, we substitute it with our alternative estimate.

6.3.2.1 Base opex

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

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

We rely on the incentives under revenue regulation and any applicable efficiency incentive scheme to determine whether a business' 'revealed' opex is efficient.[47] We also assess the evidence the business submits to demonstrate the efficiency of its base opex.

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

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

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

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

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

We also note that any volatility of total opex from year-to-year does not typically affect our choice of the appropriate base year when an ECM applies. A consequence of the operation of the ECM is that the forecast opex allowance (including ECM rewards and penalties) is largely uninfluenced by the choice of base year. For example, although using a base year with unusually high opex would typically result in an increased opex forecast, this would be offset by a lower ECM reward (or a greater penalty).

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

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

6.3.2.2 Rate of change

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

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

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

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

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

6.3.2.3 Step changes and category-specific forecasts

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

Step changes

Step changes should not double count costs included in other elements of the total opex forecast. For example, the costs of increased volume or scale should be compensated for through the output growth component of the rate of change and, as such, should not be accommodated through a step change. In addition, forecast productivity growth may account for the cost of increased regulatory obligations over time—that is, 'incremental changes in obligations are likely to be compensated through a lower productivity estimate that accounts for higher costs resulting from changed obligations.'[48] Therefore, we consider only new costs that do not reflect the historic 'average' change as accounted for in the productivity growth forecast require step changes.

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

The test we apply is whether the step change is needed for the opex forecast to comply with the opex criteria.[49] Our starting position is that only exceptional circumstances would warrant the inclusion of a step change in the opex forecast because they may change a business' fundamental opex requirements. Two typical examples are:

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

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

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

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

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

[49] NGR, r. 91.

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

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

Category specific forecasts

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

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

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

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

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

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

6.3.3 Interrelationships

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

- the operation of the ECM in the 2015–20 access arrangement period, which provides 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 used to forecast output growth
- the impact of cost drivers that affect both forecast opex and forecast capex, including forecast labour price growth
- our assessment of the rate of return, to ensure there is consistency between our determination of debt raising costs and the rate of return building block
- interactions and trade-offs between the opex and capex proposals, including JGN's proposal to expense all of its corporate overheads, rather than capitalising a portion of them, and to expense its pigging costs
- the outcomes of JGN's consumer engagement in developing its regulatory proposal.

6.4 Reasons for draft decision

Our draft decision is to not accept JGN's amended total opex forecast of $1120.5 million ($2019–20), including debt raising costs, for the 2020–25 period.[50]

We are not satisfied JGN's forecast opex meets the opex criteria[51] and the requirements for forecasts and estimates.[52] We consider that some forecast inputs have not been arrived at on a reasonable basis or do not represent the best forecast or estimate possible in the circumstances.[53] Consequently, we are not persuaded that the resulting total opex forecast meets the opex criteria.[54]

We consider that our alternative estimate of total forecast opex of $1096.6 million ($2019–20), including debt raising costs, for the 2020–25 period meets the opex criteria, subject to it being updated to incorporate the:

- outcome of our review of the additional information we request JGN include in its revised proposal regarding its demand forecasts (see Attachment 12 of this draft decision)

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50 JGN, *Response to AER information request 44*, 8 October 2019.

51 NGR, r. 91.

52 NGR, r. 74.

53 NGR, r. 91.

54 NGR, r. 74.

- most up-to-date cost of replacement gas for forecasting the UAG allowance (see section 6.4.5.3).

Our alternative estimate of total opex is $23.8 million ($2019–20), or 2.1 per cent, lower than JGN's amended opex forecast of $1120.5 million ($2019–20), including debt raising costs, for the 2020–25 period.[55]

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

Table 6.4 AER's draft decision on opex and JGN's proposed opex for the 2020–25 access arrangement period ($ million, 2019–20)

	JGN's initial proposal[56] (1)	JGN's amended proposal[57] (2)	AER's draft decision on opex (3)	Difference ((3)–(2))
Based on reported opex in 2017–18	951.5	923.5	915.4	–8.1
Efficiency adjustment	–65.3	–	–	–
Base year adjustments	84.2	84.2	84.2	0.0
2017–18 to 2019–20 increment	–4.1	21.3	21.1	–0.2
Output growth	37.6	40.9	38.0	–2.9
Price growth	14.3	15.5	6.1	–9.4
Productivity growth	–17.9	–19.5	–19.3	0.2
Step changes	–0.7	–0.7	–0.7	0.0
Category specific forecasts	36.9	46.0	46.3	0.2
Total opex (excluding debt raising costs)	**1036.6**	**1111.2**	**1091.0**	**–20.2**
Debt raising costs	9.3	9.3	5.6	–3.7
Total opex (including debt raising costs)	**1045.9**	**1120.5**	**1096.6**	**–23.8**

Source: JGN, *2020–25 Access Arrangement Proposal – Attachment 6.2 – Opex Model,* June 2019; JGN*, Response to AER Information request 44 – Opex Model,* 8 October 2019; AER analysis.

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

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55 JGN, *Response to AER information request 44*, 8 October 2019.

56 As submitted by JGN on 28 June 2019.

57 As submitted by JGN on 8 October 2019.

Key reasons why we have substituted JGN's amended opex proposal with our alternative opex estimate for the 2020–25 period are:

- we are not satisfied that JGN's forecast of inflation through to June 2020 represents the best forecast possible in the circumstances. We have used a more recent inflation forecast from the RBA.[58]
- we are not satisfied that JGN's forecast of labour price growth represents the best forecast possible in the circumstances. JGN used an average of forecasts of NSW utilities industry WPI growth from both BIS Oxford and Deloitte. However, we recently analysed the accuracy of these two forecasters over the period 2007 to 2018 and found BIS Oxford over forecast WPI growth.[59] Consequently, we do not consider BIS Oxford's WPI, nor an average of BIS Oxford's and Deloitte's represents the best forecast in the circumstances. We have forecast labour price growth using only Deloitte's forecasts.[60]
- we are not satisfied that JGN's forecast of customer numbers and mains length represent the best forecast possible in the circumstances. We have updated our forecasts of customer numbers and mains length to reflect our draft decision on JGN's forecasts of capex and demand. We discuss demand and capex forecasts in Attachments 5 and 12 of this draft decision, respectively.

We discuss these reasons in more detail below. Full details of our alternative estimate are set out in our opex model, which is available on our website.

6.4.1 Amendments to JGN's opex forecast

We have based our draft decision on JGN's amended total opex forecast of $1120.5 million ($2019–20), including debt raising cots, for the 2020–25 period which it submitted to us on 8 October 2019.[61] JGN submitted its initial opex proposal on 28 June 2019. However, in response to concerns we raised regarding its proposed base year, JGN submitted an amended opex proposal on 2 September 2019. It subsequently amended its opex proposal further on 8 October 2019 to correct errors it identified. We discuss these amendments below.

In its initial opex forecast, JGN used estimated 2018–19 expenditure as the starting point to forecast opex. In doing this, JGN adjusted the estimated 2018–19 expenditure to exclude transformation costs that it stated were non-recurrent.[62] JGN then proposed to treat this adjustment as an efficiency gain in its ECM calculations, even though the efficiency gain had not yet been realised. This resulted in a positive efficiency

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58 RBA, *Statement on Monetary Policy—Appendix: Forecast*, August 2019.

59 See AER, *Draft Decision, SA Power Networks Distribution Determination 2020 to 2025, Attachment 6 – Operating Expenditure, pp. 28–32.*

60 Deloitte Access Economics, *Labour price growth forecasts prepared for the AER*, 24 June 2019.

61 NGR, r. 58(3).

62 JGN, *2020–2025 Access Arrangement Proposal – Attachment 6.1 – Operating expenditure*, June 2019, pp. 10–12.

carryover amount of $61.8 million ($2019–20),[63] which is higher than it otherwise would be. We considered that this approach reduces transparency in the calculation of the efficiency carryover amounts that reward JGN for the incremental efficiency gains it has actually made. We consider that if 2018–19 opex is abnormally high because of non-recurrent transformation costs, then our preferred approach is to adopt a different base year.[64]

We raised our concerns about the use of 2018–19 as the base year (and the associated adjustment to remove non-recurrent costs) with JGN. In response, JGN submitted an amended opex forecast of $1115.0 million ($2019–20) and an amended ECM calculation on 2 September 2019.[65] This revised opex forecast adopted 2017–18 as the base year and did not remove any non-recurrent costs from base opex. JGN revised its ECM calculation to be consistent.[66]

On 8 October 2019, JGN submitted another amended opex forecast of $1120.5 million ($2019–20) to rectify an error in its reported movements in provisions. It also submitted a revised ECM carryover calculation to correct the same error.[67] It is this amended opex forecast that we have assessed in this draft decision.

6.4.2 Base opex

We have used an estimate of JGN's opex for 2019–20 of $204.1 million ($2019–20) to derive our alternative opex estimate. Table 6.5 sets out our estimate of opex for 2019–20, which we explain further in the sections below.

The small difference between our alternative estimate of 2019–20 opex and the estimate in JGN's amended proposal of $205.8 million ($2019–20) is due to the use of different inflation forecasts and movements in provisions. We have used the latest inflation forecasts published by the RBA.[68] We consider these inflation forecasts are the best forecast possible in the circumstances because they are the most up-to-date information available at the time.[69]

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63 JGN, *2020–2025 Access Arrangement Proposal – Attachment 7.6 – ECM Model,* June 2019.

64 AER, *Explanatory Statement, Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013, pp. 14–16.

65 JGN, *Response to AER Information request 21 – Opex Model, 2 September 2019.*

66 JGN, *Response to AER Information request 21 – Opex Model, 2 September 2019.*

67 JGN, *Response to AER information request 44*, 8 October 2019.

68 RBA, *Statement on Monetary Policy—Appendix: Forecast*, August 2019.

69 NGR, r. 74(2).

Table 6.5 AER's forecast of base opex ($million, 2019–20)

	Our base opex
Reported 2017–18 opex	181.5
Remove reported movement in provisions	1.6
Add estimated change in opex between the base year and the final year	4.2
Estimated 2019–20 opex under current capitalisation policy	**187.3**
Add additional opex due to the expensing of corporate overheads	16.8
Estimated 2019–20 opex under new capitalisation policy	**204.1**

Source: AER analysis

Which year should be used as the base year?

We have relied on JGN's reported opex in 2017–18 to calculate our alternative estimate of base opex for the 2020–25 period. JGN initially used its estimated opex in 2018–19 as its base year opex.

We are not satisfied that JGN's initially proposed estimated opex in 2018–19 of $190.3 million ($2019–20) is a reasonable basis for forecasting total opex.[70] JGN's estimated 2018–19 opex included transformation costs of $13.1 million ($2019–20), which JGN claimed were non-recurrent.[71] JGN removed these transformation costs from its estimated 2018–19 opex when it forecast its proposed total opex. It stated that it would bear the ongoing costs and risks of the program.[72] Correspondingly, JGN treated the resulting decrease in opex as an efficiency reward in its ECM carryover calculations.[73] The result of this was to transfer $65.3 million ($2019–20) from JGN's proposed opex forecast to its proposed ECM carryover amounts.

JGN's approach differs from our preferred approach for the treatment of material one-off costs incurred in the base year, which we set out in our efficiency benefit sharing scheme (EBSS) explanatory statement.[74] When one-off factors impact expenditure in the proposed base year, our preferred approach is to choose an alternative year uninfluenced by these factors.[75]

Consistent with our preferred approach, we have used JGN's reported opex in the 2017–18 of $173.8 million ($2019–20) as the starting point in determining our alternative estimate of total opex. We consider that the opex JGN reported in 2017–18

70 NGR, r. 74.

71 JGN, *2020–2025 Access Arrangement Proposal – Attachment 6.1 – Operating expenditure*, 30 June 2019, p. 11.

72 Ibid.

73 Ibid.

74 AER, *Explanatory Statement, Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013.

75 Ibid, pp. 14–16.

is a reasonable basis for forecasting total opex for the 2020–25 period.[76] The actual opex incurred in 2017–18 is similar to the opex reported in previous years and there is no evidence to suggest JGN's expenditure drivers will change materially in the forecast period compared to those in 2017–18. Additionally, it is unaffected by abnormal non-recurrent costs, is not an estimate and has already been audited.

We discussed the implication of selecting a different base year with JGN.[77] Consequently, on 2 September 2019 JGN submitted an amended opex forecast, which adopted 2017–18 as the base year.[78] JGN maintained that its initial proposal was reasonable, but considered that our approach of using 2017–18 would also be reasonable and appropriate, provided its opex forecast and ECM carryovers both reflect a 2017–18 base year.[79]

We note that JGN further updated its amended opex forecast on 8 October 2019 to correct an error in its reported movements in provisions.[80]

We note the choice of base year affects not only affects our alternative opex estimate, but also our calculation of ECM carryover amounts. Although adopting 2017–18 as the base year, instead of 2018–19 as proposed by JGN, yields a higher opex forecast this is offset by a reduction in the ECM carryover amounts JGN will receive. We discuss the ECM implications further in Attachment 8 of this draft decision.

Is base year opex efficient?

JGN is subject to the incentives of an ex ante regulatory framework, including the application of the ECM for opex. Typically, where a service provider is subject to these incentives, we are satisfied there is a continuous incentive for a service provider to make efficiency gains and it does not have an incentive to increase its opex in the proposed base year.[81]

We have also considered benchmarking undertaken by Economic Insights, which JGN commissioned to assess the efficiency of its base year expenditure.[82] Economic Insights considered that JGN's average opex per customer was comparable with other gas distribution businesses that also have relatively high customer density, when customer density is controlled for.[83]

Benchmarking is a way of determining how well a network business is performing against its peers and over time, and provides valuable information on what is 'best

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76 NGR, r. 74.

77 AER, *Information request to JGN IR21 – Opex Base Year*, 29 August 2019.

78 JGN, *Response to AER information request 21 – Opex Transformation Costs – Response to Q1*, September 2019, p. 2.

79 Ibid.

80 JGN, *Response to AER information request 44*, 8 October 2019.

81 NGR, r.71(1).

82 JGN – Attachment 6.4 – Economic Insights – *Relative efficiency and forecast productivity growth of JGN*, June 2019.

83 Economic Insights, *Relative efficiency and forecast productivity growth of JGN*, June 2019, p. 24.

practice'. We note that we do not do annual benchmarking analysis of gas distributors, like we do for electricity distributors. Nonetheless, numerous benchmarking studies have been done of gas distributors that provide useful insights.

Economic Insights stated that JGN appears to be close to the average across all gas distributors for most of the efficiency measures in its analysis. However, it acknowledged that its comparison does not control for other opex cost drivers that may be relevant; therefore, caution should be exercised in drawing inferences.[84]

Economic Insights' findings suggest that JGN does not have any material inefficiency and does not require an adjustment to its base year opex.[85] While Economic Insights' report refers to JGN's initially proposed base year of 2018–19, the analysis examines the historical efficiency performance of JGN over the period of 1999–2018[86] and indicates that JGN is a relatively efficient performer in its use of opex inputs.[87]

We agree with Economic Insights that the conclusions from its benchmarking analysis should be treated with caution. This analysis is limited by the small sample size of gas distribution businesses and it is difficult to test some of the underlying data sources—among other things. However, as set out above, and in the absence of any evidence to the contrary, we are satisfied that the 2017–18 base year opex is efficient.

Movements in provisions

We have removed the total movement in provisions of –$1.6 million ($2019–20) attributable to opex that JGN reported for 2017–18 in constructing our alternative estimate of total opex. We used the amounts that JGN reported in its regulatory information notice (RIN).[88] We typically assess base year expenditure exclusive of any movements in provisions so our alternative estimate is based on actual costs incurred by the business. This ensures that the reported opex amount we use for base opex is uninfluenced by the assumptions used to value provisions set aside for liabilities that have not yet been paid out.

In its amended opex forecast submitted on 2 September 2019, JGN removed movements in provisions of $0.44 million ($2019–20) attributable to opex in 2017–18. However, on 8 October 2019, JGN noted an error in the movements in provisions it used in its opex forecast and its RIN response.[89] Accordingly, it provided an amended opex forecast and ECM calculation, which revised to the movement in provisions for 2017–18.

84 Ibid, p. 30.

85 Ibid, p. 81.

86 Ibid, p. 4.

87 Ibid, p. 65.

88 JGN, *Response to AER information request 44*, 8 October 2019.

89 Ibid.

However, we were unable to reconcile the movements in provisions reflected in these amended models to that reported in the reset RIN. Therefore, we have relied on the amounts reported in the RIN, which are audited amounts.[90]

JGN advised that the provision amounts it reported in its RIN omitted a provision account. However, it did not submit supporting information. Therefore, for the purpose of this draft decision, we have used movements in provisions as reflected in the RIN submitted as part of JGN's initial proposal in June 2019. JGN noted that when it submits its 2018–19 annual RIN, it will also provide corrected and audited provisions amounts for 2017–18. We will take these into account in our final decision.[91]

Estimate of 2019–20 opex

We need to estimate opex for the final year of the current (2015–20) period because we will not have a reported opex amount at the time of our final decision in April 2020. It is important our final year estimate is the same as that used in the efficiency carryover mechanism. This allows the service provider to retain incremental efficiency gains made after the base year through its opex forecast. We have estimated 2019–20 opex as follows:

$$A^*_{2019-20} = F_{2019-20} - (F_b - A_b) + non-recurrent\ efficiency\ gain_b$$

Where:

- $A^*_{2019-20}$ is the best estimate of actual opex for the final year of the 2015–20 period
- $F_{2019-20}$ is the allowed opex forecast for the final year of the 2015–20 period
- F_b is the allowed opex forecast for the base year, 2017–18
- A_b is the amount of reported opex in the base year, 2017–18
- $non-recurrent\ efficiency\ gain_b$ is the non-recurrent efficiency gain in the base year.

We have used 2017–18 as the base year and have not applied any adjustment for non-recurrent efficiency gains in the base year, consistent with JGN's amended proposal. Applying this approach, we have estimated actual opex of $187.3 million ($2019–20) for 2019–20.

Changing treatment of corporate overhead costs

We have added $16.8 million ($2019–20) to our estimate of 2019–20 opex to account for JGN's proposed capitalisation policy change.

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90 Ibid.

91 JGN, *Correspondence to the AER*, 15 October 2019.

JGN proposed to change how it classifies corporate overheads from capital to operating expenditure, in line with changes to its accounting practice.[92] In doing this, JGN will adopt the same approach to allocating costs as in the cost allocation methodology (CAM) that we have approved for Jemena Electricity Networks (JEN).[93] JGN submitted that the proposed treatment of corporate overheads for the 2020–25 period would ensure alignment between its regulatory and statutory accounts, recognising that the nature of corporate overheads has changed in recent years.[94]

In its submission, Origin did not agree with JGN's proposed expensing of corporate overheads or the rationale provided by JGN.[95] Origin encouraged us to review JGN's proposal to ensure compliance with accepted cost allocation principles.[96] Origin considered that JGN failed to provide a sufficient rationale for the expensing of these costs. It stated that there is no requirement for regulatory and statutory accounts to align.[97] However, the CCP19 generally supported JGN's proposal, stating, there is a reasonable basis that this change in the treatment of corporate overheads is likely to deliver long term benefit to consumers.[98]

We have reviewed JGN's proposed approach to forecast corporate overheads and we are satisfied that it is reasonable. The expensed corporate overheads are consistent with the new CAM—and JGN has made the required offsetting changes to its capex forecast, which does not include any capitalised corporate overheads.

Under the National Electricity Rules (NER), network services providers must submit their proposed CAM to us for approval, and we must approve a proposed CAM that complies with the *Cost Allocation Guidelines*.[99] By contrast, the NGR do not contain a formal cost allocation framework for gas networks. That is, we are not required to assess a change in JGN's approach to allocating costs or its capitalisation policy. However, in assessing the efficiency and prudency of JGN's forecast opex, we are mindful of the relevant cost allocation principles set out in the NER and the *Guidelines*. Accordingly, we have had regard to the relevant principles and processes in the context of JEN's CAM assessment process. Our decision to approve JEN's CAM is on our website.[100]

We agree with Origin that there is no requirement for regulatory and statutory accounts to align. However, the NGR do not contain a formal cost allocation framework for gas networks. The NGR do not require us to assess a change in JGN's cost allocation or capitalisation policy. As explained above, we consider that JGN's proposal has not

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92 JGN, *Jemena Gas Networks 2020 Plan*, June 2019, p. 72.

93 JGN, *2020–2025 Access Arrangement Proposal – Attachment 6.1 – Operating expenditure*, June 2019, p. 11.

94 Ibid, p. 2.

95 Origin, *Submission on JGN 2020–25 AA Proposal*, 8 August 2019, p. 2.

96 Origin Energy, *Submission on JGN 2020–25 AA Proposal*, 8 August 2019, p. 1.

97 Origin Energy, *Submission on JGN 2020–25 AA Proposal*, 8 August 2019, p. 7.

98 CCP19, *Submission on JGN 2020–25 AA Proposal,* August 2019, pp. 24–26.

99 NER, cl. 6.15.2.

100 AER, *Jemena Electricity Networks (Vic) Ltd Revised Cost Allocation Method, AER Final Decision,* May 2019, available here.

contravened the cost allocation principles, and it is consistent with the CAM that we approved for JEN.

JEN's CAM will become effective from 1 January 2021. To reflect this, JGN proposed a negative step change of $8.4 million to take out 6 months of expensed corporate overheads. We discuss this in section 6.4.4.

6.4.3 Rate of change

Once we have estimated opex in the final year of the 2015–20 period, we apply a forecast annual rate of change to forecast opex for the 2020–25 period.

We have applied a forecast average annual rate of change of 0.94 per cent. This is lower than JGN's forecast of 1.34 per cent. We compare both forecasts in Table 6.6.

Table 6.6 AER's draft decision and JGN's proposed forecast annual rate of change in opex for the 2020–25 access arrangement period (per cent)

	2020–21	2021–22	2022–23	2023–24	2024–25
JGN's proposal					
Input price growth	0.44	0.63	0.71	0.69	0.63
Output growth	1.68	1.47	1.38	1.37	1.41
Productivity growth	0.74	0.74	0.74	0.74	0.74
Opex rate of change	**1.38**	**1.35**	**1.36**	**1.32**	**1.30**
AER's draft decision					
Input prices	0.10	0.33	0.25	0.29	0.40
Output growth	1.54	1.40	1.34	1.35	1.40
Productivity growth	0.74	0.74	0.74	0.74	0.74
Opex rate of change	**0.90**	**0.99**	**0.85**	**0.90**	**1.05**

Source: AER analysis; *JGN Response to AER information request 44 – Opex Model,* 8 October 2019.

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

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

- a different approach to forecasting labour price growth
- updated output forecasts to reflect our decision on demand forecasts.

We discuss both of these issues below.

6.4.3.1 Forecast price growth

We have applied a real average annual price growth of 0.3 per cent to develop our alternative estimate of total opex. This increased our total opex alternative estimate by

$6.1 million ($2019–20). It compares to JGN's proposed average annual price growth of 0.6 per cent, which increased its total opex forecast by $15.5 million ($2019–20).[101]

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

- To forecast labour price growth, we have used the most up-to-date forecast of growth in the utilities WPI for NSW as forecast by our consultant, Deloitte.[102] This is a change to our previous approach of averaging the WPI growth forecasts provided by Deloitte and the consultant engaged by the business. This change reflects our analysis that over the period 2007 to 2018, Deloitte’s real WPI growth forecasts have been more accurate.[103] Therefore, it is consistent with the forecasting and estimate requirement under the NGR.[104] In contrast, JGN adopted our previous approach, taking the average of the utilities WPI forecasts applied by us in our draft decisions for the NSW electricity distributors and that of their consultant, BIS Oxford Economics.[105]
- Both we and JGN applied a forecast non-labour real price growth rate of zero.[106]
- We and JGN have applied the same weights to account for the proportions of opex that is labour and non-labour, 59.7 per cent and 40.3 per cent, respectively.[107]

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

Deloitte will provide us updated labour price growth forecasts after the draft decision that we will use in our final decision.

6.4.3.2 Forecast output growth

We have adopted JGN’s approach to forecast output growth. However, we are not satisfied that JGN’s forecast of customer numbers and mains length represent the best forecasts possible in the circumstances.[108] Consequently we have updated JGN’s customer numbers and mains length forecasts to reflect our draft decision on capex and demand forecasts, which are set out in Attachments 5 and 12 of this draft decision, respectively. As a result, we forecast average annual output growth of 1.41 per cent.

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101 JGN, *2020–2025 Access Arrangement Proposal – Attachment 6.1 – Operating expenditure*, 30 June 2019, p. 14.

102 Deloitte Access Economics, *Labour price growth forecasts prepared for the Australian Energy Regulator*, 24 June 2019.

103 Stakeholders raised concerns with the labour price growth forecasts in submissions to SA Power Networks’ proposal for the 2020–25 revenue determinations. Consequently, we analysed how close the forecasts from both Deloitte and BIS Oxford Economics have been to actual WPI growth over the period 2007 to 2018. We found BIS Oxford Economics persistently over-forecast real WPI growth. In contrast, Deloitte’s real WPI growth forecasts have been more accurate. See AER, *Draft Decision, SA Power Networks Distribution Determination 2020 to 2025, Attachment 6 – Operating Expenditure, pp. 28–32.*

104 NGR, r 74(2).

105 JGN, *2020–2025 Access Arrangement Proposal – Attachment 6.1 – Operating expenditure*, 30 June 2019, p. 14.

106 JGN, *2020–2025 Access Arrangement Proposal – Attachment 6.1 – Operating expenditure*, 30 June 2019, p. 14.

107 JGN, *2020–2025 Access Arrangement Proposal – Attachment 6.1 – Operating expenditure*, 30 June 2019, p. 14.

108 NGR, r. 74(2).

This increases our alternative estimate of total opex by $38.0 million ($2019–20). This compares with 1.46 per cent proposed by JGN, which increases its proposed opex by 40.9 million ($2019–20).

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

To assess JGN's output and productivity growth forecasts, we tested whether output growth, net of productivity growth, falls with an acceptable range based on the results of previous econometric studies. The acceptable range is based on the cost functions estimated by Economic Insights[109] and ACIL Allen.[110] We consider this approach uses the best information available to establish an acceptable range.

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

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

	Proposed average annual growth rate, per cent	Acceptable range, average annual growth rate, per cent	Assessment
JGN	0.72	–0.71 to 0.74	Within acceptable range

Source: AER analysis.

6.4.3.3 Forecast productivity growth

We have adopted JGN's proposed annual productivity growth rate of 0.74 per cent. This decreases our alternative opex estimate by $19.3 million ($2019–20) for the 2025–25 period.

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

Achieving productivity gains would be consistent with JGN's past performance as well as that of other gas distribution businesses. According to the productivity performance

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109 Economic Insights, *Gas Distribution Businesses Opex Cost Function, Report prepared for Multinet Gas*, 22 August 2016; Economic Insights, *Relative Opex Efficiency and Forecast Opex Productivity Growth of Jemena Gas Networks, Report prepared for Jemena Gas Network*, February 2015; Economic Insights, *Relative Efficiency and Forecast Productivity Growth of Jemena Gas Networks (NSW), Report prepared for JGN*, 24 April 2019.

110 ACIL Allen Consulting, *Opex Partial Productivity Analysis, Report for AGN*, 20 December 2016.

study Economic Insights prepared for JGN, opex partial factor productivity index performance improved from 1999 to 2018.[111]

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

Based on the results from Economic Insights and ACIL Allen, JGN should be able to achieve opex partial factor productivity growth between 0.75 per cent and 1.45 per cent per year over the 2020–25 period. These forecasts of productivity growth are reflected in the models we used to establish the acceptable range of output growth net of productivity growth.

6.4.4 Step changes

We have included the two step changes totalling –$0.7 million proposed by JGN in our alternative estimate of opex for the 2020–25 period. These step changes are for:

- expensing corporate overheads
- pigging costs, which were capitalised in the 2015–20 period.

Table 6.8 AER's draft decision on JGN's proposed step changes for the 2020–25 access arrangement period ($ million, 2019–20)

	2020–21	2021–22	2022–23	2023–24	2024–25	Total
AER's draft decision and JGN's proposal	–8.4	–	3.3	1.3	3.1	–0.7

Source: JGN, *Response to AER Information request 44 – Opex Model,* 8 October 2019.

We discuss our assessment of these two step changes below.

6.4.4.1 Corporate overheads

We have included a step change of –$8.4 million ($2019–20) to account for the six months in the 2020–25 period in which JGN will continue to capitalise a portion of its corporate overheads, prior to its new CAM coming into effect on 1 January 2021. This step change must be considered together with the adjustment we have made to base opex that reflects JGN's accounting change in the classification of corporate overhead costs from capital to operating expenditure. This negative step change is necessary to offset our base opex adjustment for JGN's corporate overheads costs, such that our alternative estimate does not over-forecast JGN's total opex in 2020–21.

111 Economic Insights, *Relative efficiency and forecast productivity growth of JGN*, June 2019, p. 47.

6.4.4.2 Pigging costs

We have included a step change of $7.7 million ($2019–20) in our alternative opex estimate for JGN's 'pigging' and inspection costs for the 2020–25 period. This is consistent with JGN's opex proposal. JGN proposed to expense its 'pigging' costs, instead of capitalising them as it has done in the 2015–20 period.[112] JGN reduced its capex forecast by the same amount to reflect this change in cost classification.

JGN uses an intelligent pipeline inspection tool, commonly referred to as a 'pig' to inspect the thickness and conditions of pipeline walls. JGN stated that the costs of 'pigging' do not include the resultant works that may be required on its pipelines and therefore may not necessarily result in extending the lives of the pipelines.[113] JGN considered that classifying pigging and inspection costs as opex more accurately reflects the nature of these activities.

In its submission, Origin considered that JGN's ongoing treatment of 'pigging' and inspection costs appear arbitrary.[114] By contrast, the CCP19's generally supported JGN's proposal to expense pigging costs.[115] We acknowledge that JGN's classification of 'pigging' costs has been inconsistent over time. However, we consider that if the 'pigging' and inspection of pipelines do not extend the lives of the pipelines, the cost of these maintenance activities can be reasonably classified as opex.

Provided that these costs are not also included in forecast capex for JGN, we consider it acceptable to forecast JGN's pigging costs as part of our opex forecast for the 2020–25 period. We consider the proposed classification change is permissible under the NGR and there is no change in JGN's total expenditure in net present value terms. Therefore, we do not consider this step change would adversely affect the long term interests of gas consumers and we have included JGN's proposed step change in our alternative opex estimate.

6.4.5 Category specific forecasts

We have included category specific forecasts for three expenditure items in our alternative estimate of total opex for the 2020–25 period. We have not forecast these costs using the base-step-trend approach. These are debt raising costs, licence fees and UAG. Table 6.9 sets out the forecasts JGN included in its total opex forecast. We are satisfied that these amounts represent the best forecast possible in the circumstances and have included them in our alternative opex estimate.

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112 JGN, *2020–25 Access Arrangement Proposal – Attachment 6.1 Operating Expenditure*, June 2019, p. 16.

113 JGN, *2020–25 Access Arrangement Proposal – Attachment 6.1 – Operating expenditure*, 30 June 2019, p. 16.

114 Origin Energy, *Submission on JGN 2020–25 AA Proposal*, August 2019, p. 7.

115 CCP19, *Submission on JGN 2020–25 AA Proposal,* August 2019, pp. 24–26.

Table 6.9 AER's draft decision and JGN's proposed category specific opex forecasts for the 2020–25 access arrangement period ($million, 2019–20)

Category	JGN's proposal	AER's draft decision	Difference
Debt raising costs	9.3	5.6	**–3.7**
Licence fees	24.2	23.5	**–0.7**
UAG	157.5	157.5	**–**
Total	**191.0**	**186.6**	**–4.4**

Source: JGN, *Response to AER information request 44 Opex Model*, October 2019; AER analysis.

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

6.4.5.1 Debt raising costs

We have included debt raising cost of $5.6 million ($2019–20) in our alternative opex forecast for the 2020–25 period.

Debt raising costs are transaction costs incurred each time a business raises or refinances debt. Our preferred approach is to forecast debt raising costs using a benchmarking approach rather than a service provider's actual costs in a single year. This provides for consistency with the forecast of the cost of debt in the rate of return building block. We discuss this in Attachment 3 of this draft decision.

6.4.5.2 Licence fees

We have included a category specific forecast for 'licence fees' of $23.5 million ($2019–20) in our alternative estimate for the 2020–25 period. These costs will be subject to a 'true–up' in JGN's reference tariff variation mechanism. Our forecast is 2.8 per cent lower than JGN's 'government levies' forecast of $24.2 million ($2019–20), which we refer to hereafter as licence fees.

This cost category refers to the annual licence and authorisation fees that JGN pays to the NSW Government and other authorities and the mains tax it pays to local government councils.[116] Apart from mains tax, JGN's licence fees had been subject to a 'true-up' through its 'licence fee factor' in its reference tariff variation mechanism in the 2015–20 period.[117] A 'true-up' refers to an adjustment to JGN's reference tariff to pass through costs to JGN's consumers based on updates to observable data, being the difference between JGN's actual licence fee costs and our forecast.

116 JGN, *2020–25 Access Arrangement Proposal – Attachment 6.1 Operating Expenditure*, June 2019, p. 19.

117 JGN, *Response to AER Information Request 14 – Attachment 3 TVN Licence fee and UAG documentation (Confidential)*, 20 August 2019; JGN, *Response to AER Information Request 41 – Government levies forecast* , 3 October 2019, p. 4.

JGN's 'government levies' forecast for the 2020–25 period only includes the forecasts of:

- its mains tax levied by local government councils under section 611 of the Local Government Act 1993 (NSW)
- its annual authorisation fees payable to the Independent Pricing & Regulatory Tribunal (IPART) for JGN's gas reticulation licence (IPART fees).[118]

JGN stated that it based its forecast on the costs it would pay to each government agency in 2018–19, holding the costs constant in real dollar terms.[119]

JGN also stated that it incurs additional licence fees that are captured under the base year opex line item and which are trued up under its reference tariff variation mechanism (via the licence fee factor). These include:

- Energy & Water Ombudsman NSW (EWON) annual fee, customers number fees and quarterly fees based on projected case work
- annual licence fees payable to the NSW Department of Planning and Environment for individual pipelines, including Pipelines Licence Numbers 1, 2, 3, 7, and 8 (pipeline fees).

JGN proposes to include these additional licence fees in the category specific forecast in its upcoming 2020–25 revised proposal.[120]

For consistency in our terminology, we have termed our category specific forecast 'licence fees', as opposed to 'government levies', so that it corresponds with the 'licence fee factor' we define for JGN's reference tariff variation mechanism and the 'licence fees' category we exclude from the ECM in the 2020–25 period.

The 'licence fees' forecast in our alternative estimate comprises forecasts of JGN's:

- mains tax
- IPART authorisation fees
- pipeline fees.

Noting that the individual local government council invoicing can be irregular, JGN considered the source data that it had provided to KPMG for auditing its mains tax liability in 2017–18 to be most accurate indication of JGN's annual mains tax.[121] We consider that using the revealed 'incurred' costs in the base year does not accurately capture the mains tax JGN accrued in 2017–18 and, therefore, we have relied on the

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118 JGN, *Response to AER Information Request 18 (Q4) – Opex: Multiple Matters (Confidential)*, 29 August 2019, p. 3.

119 JGN, *2020–25 Access Arrangement Proposal – Attachment 6.1 Operating Expenditure*, June 2019, p. 19.

120 JGN, *Response to AER Information Request 18 (Q4) – Opex: Multiple Matters (Confidential)*, 29 August 2019, p. 4.

121 JGN, *Response to AER Information Request 41 – Government levies forecast* , 3 October 2019, p. 3.

dataset which JGN provided to KPMG to forecast JGN's mains tax.[122] We escalated our forecast of JGN's mains tax with the same inflation figures we used in our opex forecast.

We forecast JGN's IPART authorisation fees using the most recent invoice (2015–16). JGN explained that it does not receive invoices from IPART regularly and therefore does not incur the IPART fees yearly, despite accruing them annually.[123] The irregular timing of IPART's invoices suggests that it would be inappropriate for us to forecast JGN's IPART fees based on JGN's revealed 'incurred' cost in the base year (which is nil). Based on the invoices JGN had received to date, IPART fees do not appear to change significantly. We are satisfied that JGN's 2015–16 invoice provides a good indication of JGN's future IPART fees.

We have removed JGN's 2017–18 pipeline fees from its 2017–18 base year opex. We agree with JGN's proposed approach to forecast these costs as part of our 'licence fees' category.[124] We have forecast them based on the most recent (2018–19) invoices JGN has received. JGN's 2018–19 pipeline fees are similar to the six-year average we calculated based on JGN's pipeline fees from 2013–14 to 2018–19. We are therefore satisfied that this is the best forecast given the available information.

EWON fees

We have not removed JGN's EWON fees from our estimate of 2019–20 opex and included them in our 'licence fees' forecast as proposed by JGN.[125] This is because we consider it would be in the long term interests of gas consumers to allow JGN to true-up its EWON fees.

EWON charges JGN for individual consumer complaints, thereby providing an incentive for JGN to improve its internal complaint handling procedure such that fewer consumers would need to approach EWON to resolve their complaints. Subjecting JGN's EWON fees to a true-up in its reference tariff variation mechanism would remove JGN's incentive to reduce its EWON fees and make JGN's customers bear the cost of those fees.

Including JGN's EWON fees in our base-step-trend forecast, and excluding this cost from the application of automatic adjustment in JGN's reference tariff variation mechanism, will provide JGN an incentive to reduce its EWON fees and reduce customer complaints. EWON fees will be subject to the application of the ECM in the same way as the other costs included in our base-step-trend opex forecast.

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[122] JGN, *Response to AER Information Request 41 – Government levies forecast* , 3 October 2019.

[123] JGN, *Response to AER Information Request 18 (Q4) – Opex: Multiple Matters (Confidential)*, 29 August 2019, p. 4.

[124] JGN, *Response to AER information request 41 – Government levies forecast* , 3 October 2019; *Response to AER information request 18 – Multiple matters (Confidential)*, 3 October 2019.

[125] JGN, *Response to AER Information Request 18 (Q4) – Opex: Multiple Matters (Confidential)*, 29 August 2019.

We have amended the definition of JGN's licence fee factor in its reference tariff variation mechanism to align it with our opex draft decision (see Attachment 10). This will provide greater transparency and certainty on what costs are subject to a true-up and what costs we expect JGN to manage within its total opex forecast.

6.4.5.3 Unaccounted for gas

Unaccounted for gas (or 'UAG') is the difference between the measured quantity of gas entering the network system (gas receipts) and metered gas deliveries (gas withdrawals).[126] It may be attributable to gas leakage, inaccuracies in gas measurement or gas theft. JGN is required to replace any UAG.[127] UAG is generally expressed as a percentage of gas receipts into the network.

JGN's access arrangement includes an incentive to minimise UAG. If the actual UAG rate is below (above) JGN's target UAG rate, JGN over (under) recovers its actual UAG costs. If actual market volumes or the cost of purchasing UAG differs from the approved forecast, JGN is compensated through the tariff variation mechanism.

We accept JGN's UAG cost forecast of $157.5 million ($2019–20) in our alternative estimate of forecast total opex for the 2020–25 period, subject to JGN updating the:

- forecast of total gas receipts to reflect our draft decision on forecast demand
- escalation factor it applied to forecast the cost of replacement gas to reflect information relating to 2019 that has become available since it submitted its 2020–25 proposal.

We note that the final UAG forecast we include in our opex forecast will need to reflect the final demand forecast we approve and the up-to-date inflation forecasts at the time of making our final decision. We discuss our draft decision on JGN's demand forecast in Attachment 12.

Table 6.10 sets out our draft decision on UAG costs for each year of the 2020–25 period.

Table 6.10 AER's draft decision and JGN's proposed forecast UAG costs for the 2020–25 access arrangement period ($ million, 2019–20)

	2020–21	2021–22	2022–23	2023–24	2024–25	Total
AER's draft decision and JGN's proposal	31.2	31.6	31.7	31.6	31.4	**157.5**

Source: JGN, *Response to AER information request 44: Opex Model*, 8 October 2019; AER analysis.

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

126 JGN, *2020–25 Access arrangement proposal – Attachment 6.7 – Unaccounted for gas (Confidential)*, June 2019, p. iv.

127 JGN, *Reference Service Agreement - JGN's NSW gas distribution network 1 July – 30 June 2025*, clauses 9.4 and 9.5(e), June 2019, p. 31.

Consistent with the approach we adopted in our 2015–20 decision for JGN and JGN's 2020–25 proposal, we have calculated UAG costs forecast based on the product of:[128]

- the approved target rate of UAG
- total gas receipts (or demand)
- the cost of replacement gas.

We discuss each of these below.

Target rate of UAG

We have adopted JGN's target UAG rates to forecast UAG costs. JGN used two target UAG rates: one for its non-daily metered customers (residential and small commercial) and another for its daily-metered customers (larger, industrial customers).[129]

JGN considered that a significant majority of the contributors to UAG (such as leakage and metering uncertainty) apply to non-daily metered customers. In contrast, almost all daily-metered customers are supplied from high-pressure pipes, which have negligible leakage and less metering uncertainty.[130] JGN considered this supports the allocation of a lower UAG rate to daily-metered customers and a higher UAG rate to non-daily metered customers.[131]

We are satisfied that JGN's dual rate approach, and its allocation of a lower UAG rate to daily-metered customers and a higher UAG rate to non-daily metered customers, is reasonable. This also reflects our 2015–20 decision for JGN.[132] Further, it is also consistent with the dual rate approach and the ratios between the rates used by the Victorian Essential Services Commission (ESC) for the Victorian pipeline service providers.[133]

We have applied JGN's target UAG rates to forecast UAG costs:[134]

- 0.705 per cent of forecast withdrawals for the daily metered or demand market
- 5.925 per cent of forecast withdrawals for the non-daily metered or volume market.

These target rates are based on JGN's proposed total UAG of 2.866 per cent.[135]

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128 JGN, *2020–25 Access arrangement proposal – Attachment 6.1 – Operating expenditure*, June 2019, p. 18; AER, *Draft decision Jemena Gas Networks Access arrangement – Attachment 7 – Operating expenditure*, November 2014, pp. 7–25.

129 JGN, *2020–25 Access arrangement proposal – Attachment 6.7 – Unaccounted for gas*, June 2019, p. iv.

130 JGN, *2020–25 Access arrangement proposal – Attachment 6.7 – Unaccounted for gas*, June 2019, p. 10.

131 JGN, *2020–25 Access arrangement proposal – Attachment 6.7 – Unaccounted for gas*, June 2019, p. 10.

132 See: AER, *Draft Decision, Jemena Gas Networks (NSW) Ltd, Access Arrangement 2015–20, Attachment 7 – Operating Expenditure*, November 2014, pp. 25–28.

133 Essential Services Commission Victoria, *Gas Distribution Code, Review of Unaccounted for Gas Benchmarks, Final Decision*, June 2013, p. 4. In Victoria, ESC sets a UAG 'benchmark' within which gas distribution businesses are expected to operate. See: Essential Services Commission, *Gas Distribution System Code*, Version 11.0, October 2014, p. 4.

134 JGN, *2020–25 Access arrangement proposal – Attachment 6.7 – Unaccounted for gas*, June 2019, p. 8.

The above rates reflect an increase relative to the target rates applied in the 2015–20 period, which were:

- 0.450 per cent of forecast withdrawals for the daily metered or demand market
- 5.44 per cent of forecast withdrawals for the non-daily metered or volume market.

JGN's proposed UAG target rates reflect a step change in its reported UAG rate. It considered that this step change occurred due a combination of factors:

- The volume of gas delivered was greater than that forecast for the 2015–20 period—this increased the actual volume of UAG relative to the forecast.[136] Additionally, the percentage of UAG increased relative to the forecast because a metering orifice plate was replaced with a new plate that 'is more accurate at measuring lower flow ranges'.[137] JGN submitted that APA changed the meter at the Moomba–Sydney Pipeline (MSP) Custody Transfer Station (CTS) at Wilton in March 2017. JGN considered that prior to its change in March 2017, the old metering orifice plate under-measured gas receipts into its network.
- Errors in JGN's enterprise reporting system masked the impact of the change at the Wilton MSP CTS metering station.[138] Prior to the meter change, JGN replaced its enterprise reporting system, transitioning from GASS+ to SAP between July 2015 and May 2016.[139] After this transition, JGN identified inaccuracies in UAG reporting within SAP in mid-2016. JGN carried out investigations to identify and correct reporting errors in a process that was finalised in late 2018. JGN submitted that the UAG step change only became apparent at the end of this process and it traced the step change back to March 2017.

JGN submitted reports from three independent experts to support its proposed target UAG rates:

- JGN commissioned Howard Wright Gas Measurement Pty Ltd (HWGM) to independently review its UAG performance, including how it calculates UAG.[140] HWGM concluded that:
    - JGN's methodology and approach to calculating and reporting UAG is appropriate.
    - JGN's UAG is comparable to other distribution networks on an energy throughput basis but is relatively low on a GJ per kilometre of distribution main basis.
    - JGN's processes for managing UAG are appropriate and in keeping with good industry practice.[141]

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135 JGN, *2020–25 Access arrangement proposal – Attachment 6.7 – Unaccounted for gas*, June 2019, p. 8.
136 JGN, *2020–25 Access arrangement proposal – Attachment 6.1 – Operating expenditure*, June 2019, pp. 3–7.
137 JGN, *2020–25 Access arrangement proposal – Attachment 6.7 – Unaccounted for gas*, June 2019, p. 8.
138 JGN, *2020–25 Access arrangement proposal – Attachment 6.7 – Unaccounted for gas*, June 2019, p. 8.
139 JGN, *2020–25 Access arrangement proposal – Attachment 6.7 – Unaccounted for gas*, June 2019, p. 8.
140 Howard Wright Gas Measurement Pty Ltd, *Jemena Gas Networks – Review of JGN UAG,* 17 June 2019.

- KPMG audited the flow of UAG data through the data collection, data processing and calculation processes, as recommended by HWGM. It found no material discrepancy in the UAG calculations.
- JGN also commissioned Frontier Economics (Frontier) to recalculate the UAG target rates for the 2020–25 period. Frontier relied on the same approach to forecast JGN's UAG rates that it adopted in the 2015–20 period,[142] which we accepted in our 2015–20 decision for JGN.[143] However, Frontier updated this approach to take into account the under-measurement of gas receipts at the Wilton CTS that took place before March 2017 as well as the most recent data.[144] Frontier also undertook a sensitivity analysis to check the validity of its results.[145]

We carefully reviewed each of these reports and further information JGN provided in response to our information requests. We are satisfied that the findings of each of these reviews are reasonable.

Total gas receipts

We have applied the total gas receipts that reflect our draft decision on JGN's demand forecast. Specifically, we have adjusted tariff V forecast demand in our alternative forecast of UAG costs to reflect our draft decision on JGN's forecast demand.

JGN's forecast UAG cost is directly related to its forecast demand because the forecast cost of UAG is the product of the approved target rate of UAG, total gas receipts, and the cost of replacement gas. JGN based its forecast demand on Core Energy's report on gas demand and customer forecasts.[146]

We accept JGN's total gas receipts forecast subject to it being updating to reflect our decision on forecast demand (Attachment 12 of this draft decision).

The cost of replacement gas

We have adopted JGN's approach to forecasting the replacement cost of gas. JGN's forecast UAG prices are based on the current gas prices JGN pays for UAG as reflected in its 2019–20 supply contract.[147] We consider this approach is sound and note that the actual cost of replacement gas will be 'trued-up' each year as part of the tariff variation process (along with the volumes received).

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141 Howard Wright Gas Measurement Pty Ltd, *Jemena Gas Networks – Review of JGN UAG,* 17 June 2019, pp. 21–22.

142 JGN, *2020–25 Access arrangement proposal – Attachment 6.7 – Unaccounted for gas*, June 2019, p. 11; Frontier Economics, *UAG Methodology – update to coefficients – A report prepared for Jemena Gas Networks*, 9 May 2019, p. 3.

143 AER, *Draft decision Jemena Gas Networks Access arrangement – Attachment 7 – Operating expenditure*, November 2014, pp. 7–28.

144 JGN, *2020–25 Access arrangement proposal – Attachment 6.7 – Unaccounted for gas*, June 2019, p. 11.

145 JGN, *2020–25 Access arrangement proposal – Attachment 6.7 – Unaccounted for gas*, June 2019, p. 11.

146 JGN, *2020–25 Access arrangement proposal – Attachment 8.2 – Core Energy - Demand Forecast Report*, June 2019.

147 JGN*, Response to AER Information request 39 (Confidential),* 26 September 2019.

We accept JGN’s forecast cost of replacement gas, subject to it updated the escalation factor applied to reflect the most up-to-date information.

6.5 Revisions

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

Table 6.11 JGN’s opex revisions

Revision	Amendment
Revision 6.1	Make all necessary amendments to reflect our draft decision on the proposed opex allowances for the 2020–25 access arrangement period, as set out in section 6.1.