



**Draft decision**

**Jemena Gas Networks (NSW) Ltd**

**Access arrangement 2015–20**

**Attachment 7 – Operating expenditure**

November 2014

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AER reference: 51741

## Note

This attachment forms part of the AER's draft decision on Jemena Gas Networks 2015–20 access arrangement. It should be read with 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 – value of imputation credits

Attachment 5 – regulatory depreciation

Attachment 6 – capital expenditure

Attachment 7 – operating expenditure

Attachment 8 – corporate income tax

Attachment 9 – efficiency benefit sharing scheme

Attachment 10 – reference tariff setting

Attachment 11 – reference tariff variation mechanism

Attachment 12 – non-tariff components

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## Shortened forms

Shortened form	Extended form
2010–15 access arrangement	Access arrangement for JGN effective from 1 July 2010 to 30 June 2015 inclusive
2010–15 access arrangement period	1 July 2010 to 30 June 2015 inclusive
2015–20 access arrangement	Access arrangement for JGN effective from 1 July 2015 to 30 June 2020 inclusive
2015–20 access arrangement period	1 July 2015 to 30 June 2020 inclusive
Access arrangement information	Jemena Gas Networks (NSW) Ltd, <i>Access Arrangement Information 2015–20</i> , 30 June 2014
Access arrangement proposal	Jemena Gas Networks (NSW) Ltd, <i>Access arrangement, JGN's NSW gas distribution networks, 1 July 2015 – 30 June 2020</i> , 30 June 2014
AER	Australian Energy Regulator
capex	capital expenditure
CAPM	capital asset pricing model
CCP	Consumer Challenge Panel
Code	National Third Party Access Code for Natural Gas Pipeline Systems
CPI	consumer price index
DRP	debt risk premium
ERP	equity risk premium
JGN	Jemena Gas Networks (NSW) Ltd (CAN 003 004 322)
MRP	market risk premium
NGL	national gas law
NGO	national gas objective
NGR	national gas rules

Shortened form	Extended form
opex	operating expenditure
PPI	partial performance indicators
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
Reference service agreement proposal	Jemena Gas Networks (NSW) Ltd, <i>Reference Service Agreement, JGN's NSW gas distribution networks</i> , 30 June 2014
RFM	roll forward model
RIN	regulatory information notice
RPP	revenue and pricing principles
SLCAPM	Sharpe-Lintner capital asset pricing model
WACC	weighted average cost of capital

## 7 Operating expenditure

Forecast opex is the forecast operating, maintenance and other non-capital costs incurred in the provision of distribution network services. It includes labour costs and other non-capital costs that a prudent service provider is likely to require during the 2015–20 access arrangement period for the efficient operation of its network.

### 7.1 Draft decision

We are not satisfied that the forecast of total opex JGN proposed reflects the opex criteria and the criteria for forecasts and estimates.<sup>1</sup> We therefore do not accept the forecast of required opex JGN included in its building block proposal. Our estimate of JGN's total required opex for the 2014–19 access arrangement period is outlined in Table 7-1.

**Table 7-1 Our draft decision on total opex—JGN (\$ million, 2014–15)**

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
JGN's proposal <sup>2</sup>	155.4	155.4	156.6	161.3	160.6	789.3
AER draft decision	154.4	153.8	154.6	159.0	157.8	779.7
Difference	-1.0	-1.5	-2.0	-2.3	-2.8	-9.6

Source: AER analysis.

Note: Excludes debt raising costs.

### 7.2 Proposal

JGN proposed total opex of \$810 million over the 2010–15 access arrangement period.<sup>3</sup> This is a two per cent real increase on actual expenditure JGN incurred in the 2010–15 access arrangement period.

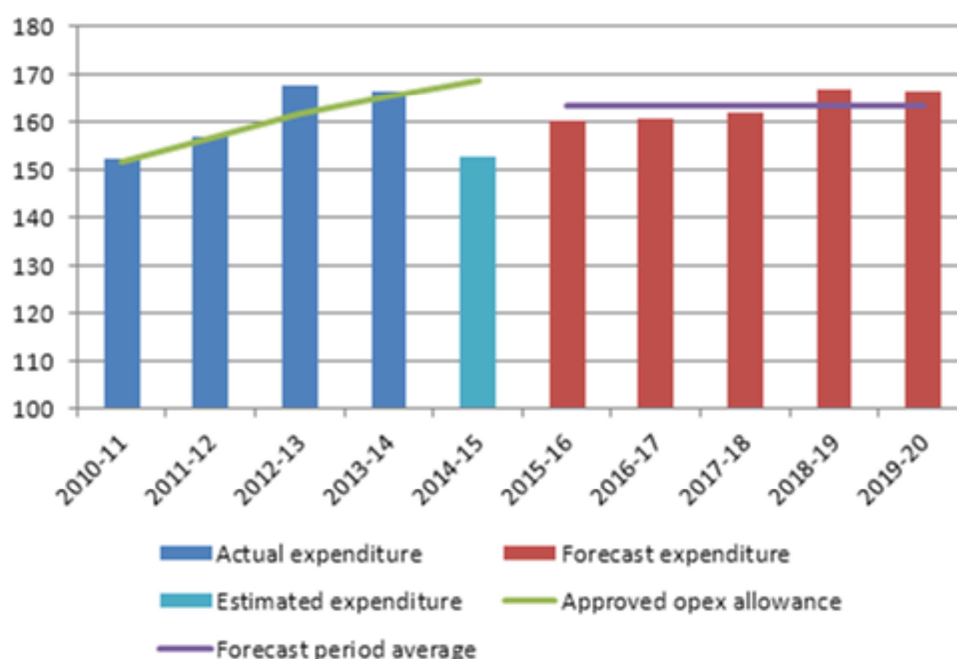
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<sup>1</sup> NGR, r. 91, r. 74.

<sup>2</sup> Subsequent to JGN's access arrangement proposal, JGN updated its forecast opex to remove costs associated with the carbon tax, corrected an error in its Unaccounted for Gas forecast and provided an updated productivity growth estimate. This changed its forecast from \$797.5 million (\$2014-15) to \$789.3 million (\$2014–15).

<sup>3</sup> Includes debt raising costs.

**Figure 7.1 JGN's historical and forecast opex (\$ million, 2014–15)**



Source: JGN, *2015–20 Access Arrangement Information*, June 2014, Appendix 7.1 Opex forecast model; AER, *JGN NSW Gas distribution networks 1 July 2010 - 30 June 2015*, 26 September 2011.

JGN forecast most of its opex using the opex it incurred in 2012–13. It trended these costs forward based on a forecast rate of change in opex, which incorporates forecast changes in prices, output and productivity.

JGN then added additional forecast costs not incurred in the base year (step changes). It developed specific forecasts of four categories of opex - government levies, unaccounted for gas, carbon costs and debt raising costs.

Table 7-2 disaggregates JGN's forecast into the different elements.

**Table 7-2 JGN's forecast opex (\$ million, 2014–15)**

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
<b>Base opex</b>	<b>133.2</b>	<b>133.2</b>	<b>133.2</b>	<b>133.2</b>	<b>133.2</b>	<b>665.8</b>
Output change	-7.6	-8.0	-2.9	-3.5	-3.3	-25.2
Price change	2.1	4.6	2.7	4.7	6.3	20.4
Productivity change	3.7	2.6	0.4	-0.6	-2.0	4.1
<b>Trend in base opex</b>	<b>-1.8</b>	<b>-0.8</b>	<b>0.2</b>	<b>0.6</b>	<b>1.00</b>	<b>-0.7</b>
NECF	2.0	1.0	1.1	1.1	1.1	6.4



	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Customer engagement	0.2	0.1	0.2	0.0	0.1	0.5
Reset costs	0.0	0.0	0.0	4.5	3.3	7.9
Annual regulatory reporting	0.4	0.4	0.4	0.4	0.4	1.9
Marketing	1.3	1.3	1.3	1.3	1.3	6.6
Insurance	0.1	0.1	0.1	0.1	0.1	0.6
<b>Total step changes</b>	<b>4.0</b>	<b>2.9</b>	<b>3.2</b>	<b>7.5</b>	<b>6.3</b>	<b>23.9</b>
Government levies	4.2	4.2	4.2	4.2	4.2	21.1
Unaccounted for gas	15.8	15.8	15.8	15.8	15.9	79.0
Carbon costs	0.0	0.0	0.0	0.0	0.0	0.2
Debt raising costs	4.0	4.0	4.1	4.2	4.2	20.6
<b>Category-specific forecasts</b>	<b>24.0</b>	<b>24.1</b>	<b>24.2</b>	<b>24.2</b>	<b>24.3</b>	<b>120.8</b>
<b>Total forecast opex</b>	<b>159.3</b>	<b>159.4</b>	<b>160.8</b>	<b>165.5</b>	<b>164.9</b>	<b>809.8</b>

Source JGN opex forecast model (Updated), October 2014.

## 7.3 Assessment approach

We decide whether or not to accept a service provider's total forecast opex proposal. We approve the service provider's forecast opex if we are satisfied that it is consistent with the criteria governing operating expenditure (the opex criteria).<sup>4</sup>

### 91. Criteria governing operating expenditure

(1) Operating expenditure must be as such as would be incurred by a prudent service provider acting efficiently to provide the lowest sustainable cost of delivering pipeline services

In determining whether forecast opex is consistent with the opex criteria we have regard to the criteria for forecasts and estimates.

### 74. Forecasts and estimates

(1) Information in the nature of a forecast or estimate must be supported by a statement on the basis of the forecast or estimate

(2) A forecast or estimate :

<sup>4</sup> Also see NGR, r. 40(2).

(a) must be arrived at on a reasonable basis; and

(b) must represent the best forecast or estimate possible in the circumstances.

Our approach is to compare the service provider's total forecast opex with our alternative estimate of total opex. By doing this, we form a view on the reasonableness of the service provider's proposal. If we are not satisfied that the proposal complies with the opex criteria we use our alternative opex estimate as a substitute.

Our estimate is unlikely to exactly match the service provider's forecast because the service provider may adopt a different forecasting method to us. However, if the service provider's inputs and assumptions are reasonable, its method should produce a forecast consistent with our estimate. Accordingly, part of our approach is to assess the service provider's forecasting method as well as the inputs and assumptions it used to form its opex forecast.

### 7.3.1 Building an alternative estimate of total forecast opex

Our approach to forming an alternative estimate of opex involves five key steps:

1. We typically use the service provider's actual opex in a single year as the starting point for our assessment. While categories of opex can vary from year to year, total opex is relatively recurrent.
2. We assess whether opex in that base year reasonably reflects the opex criteria. If necessary, we make an adjustment to the base year expenditure to ensure that it reflects the opex criteria.
3. As opex tends to change over time due to price changes, output and productivity, we trend the adjusted base year expenditure forward over the access arrangement period to take account of these changes. We refer to this as the rate of change.
4. We then adjust the base year expenditure to account for any other forecast cost changes over the forthcoming regulatory control period that would meet the opex criteria. This may be due to new regulatory obligations and efficient capex/opex trade-offs. We call these step changes.
5. Finally we add any additional opex components which have not been forecast using this approach. For instance, we forecast debt raising costs based on the costs incurred by a benchmark efficient service provider. If we removed a category of opex from the selected base year, we will need to consider what additional opex is needed for this category of opex in forecasting total opex.

We have used this general approach in our past decisions. It is a well-regarded top-down forecasting model for regulatory purposes that has been employed by a number of Australian regulators over the last fifteen years. We have sometimes referred to it as the base-step-trend method in our past regulatory decisions.

We set out more detail about each of the steps we follow in constructing our forecast below.

#### **Step 1 – Starting point - base year expenditure**

When we choose the base year, we aim to use a year that is most representative of efficient, recurrent expenditure. Typically, we start with the service provider's revealed expenditure in the second last year of the current access arrangement period. The second last year is usually the most recent available at the time we conduct our assessment. Accordingly, to the extent expenditure

drivers change over time, it is likely to best reflect the forecast period.<sup>5</sup> However, if this year does not represent efficient, recurrent costs, we may consider another year.

In choosing a base year, we need to make a decision as to whether any categories of opex incurred in the base year should be removed. For instance:

- If a material cost was incurred in the base year that is unrepresentative of a service provider's future opex we may remove it from the base year in undertaking our assessment. For this decision we removed some costs which will be reclassified as capex in the 2014–19 period.
- Rather than use all opex in the base year, service providers also often forecast specific categories of opex using different methods. We must also assess these methods in deciding what the starting point should be. If we agree that these categories of opex should be assessed differently, we will also remove them from the base year.

### **Step 2 - Assessing base year expenditure**

Regardless of the base year we choose, we must test the view that 'revealed expenditure' is the appropriate starting point because the service provider's actual expenditure may not be efficient. We will use all techniques available to us to do this. If we determine that a service provider's revealed expenditure is not efficient, we will not use it as our starting point for our estimate of total forecast opex.

### **Step 3 - Rate of change**

Once we have chosen an efficient starting point, we apply an annual escalator to take account of the likely ongoing changes to efficient opex over the forecast regulatory control period. Efficient opex in the forecast regulatory control period could reasonably differ from the efficient starting point due to changes in:

- prices
- outputs
- productivity.

We estimate the change by adding expected changes in prices (such as the cost of labour and materials) and outputs (such as changes in customer numbers and demand for electricity). We then incorporate reasonable estimates of changes in productivity.

### **Step 4 - Step changes**

We then consider if there is other opex needed to achieve the opex objectives in the forecast period. We refer to these as 'step changes'. Step changes may be for new, changed or removed obligations for the service provider in the upcoming regulatory control period, if there are efficient capex/opex trade-offs or other reasons why a service provider would need different opex to that incurred in the base year. We will typically compensate a service provider for step changes only if efficient base year opex and the rate of change in opex of an efficient service provider do not already compensate for the proposed costs.

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<sup>5</sup> The second last year is sometimes an estimate rather than audited actual expenditure. Given this, we typically use the estimate as a placeholder and update it when the service provider submits its audited accounts. If expenditure in the penultimate year is not audited at the time the service provider submits its regulatory proposal, we sometimes use the third last year because it is the most recent year of audited actual expenditure at the time.

### **Step 5 - Other costs that are not included in the base year**

In our final step, we make any further adjustments we need for our opex forecast to achieve the opex objectives. For instance, our approach is to forecast debt raising costs based on a benchmarking approach rather than a service provider's actual costs. This is to be consistent the forecast cost of debt in the rate of return building block. JGN also has several categories of opex which are subject to annual tariff variations. We must forecast opex on each these categories of opex to ensure compatibility with the annual tariff variation mechanism.

After applying these five steps, we arrive at our total opex forecast.

### **Comparing our opex forecast to the service provider's opex forecast**

If a service provider's total forecast opex is sufficiently different to our estimate, we will examine the reasons for the difference. If there is no satisfactory explanation for this difference, we may form the view that the service provider's forecast does not comply with the opex criteria. Conversely, if our estimate demonstrates that the service provider's forecast is consistent with the opex criteria, we will accept the forecast. Whether or not we accept a service provider's forecast, we will provide the reasons for our decision.

## **7.4 Interrelationships**

We note there are interrelationships between our opex forecast and other elements of JGN's In assessing JGN's total forecast opex we took into account these components, including:

- the impact of forecast capex on forecast output growth in the rate of change (see Appendix A)
- the impact of JGN's capitalisation policy on capex and opex (see section 7.5.4)
- the impact of the form of control on the forecasting methodology for licence fees, unaccounted for gas and carbon costs (see section 7.5.1).
- the impact of forecast demand on forecast output growth in the rate of change and forecast unaccounted for gas costs (see Appendix A and section 7.5.4)

## **7.5 Reasons for draft decision**

We have assessed JGN's opex forecast against our alternative estimate of opex. We are not satisfied that JGN's forecast opex for the 2015–20 access arrangement period complies with the opex criteria.

The areas of difference between our forecast and JGN's forecast are:

- Rate of change - We consider JGN's forecast of price changes is not the best estimate possible in the circumstances. As such we consider that including it in our forecast of total opex would not lead to a forecast of opex that complies with the opex criteria. We explain the reasons for the difference between our approach in section 7.5.3 and in more detail in Appendix A.
- Step changes - We have not included any forecast increase in opex related to annual regulatory reporting. We consider it is not reasonable to assume these obligations will increase materially in the 2015–20 access arrangement period.

We discuss each element of JGN's forecast opex below in this attachment. The assessment of the rate of change is discussed in more detail in Appendix A. Debt raising costs is discussed in a debt

and equity raising costs appendix. Table 7-3 summarises the quantum of the difference between JGN's proposed total forecast opex and our draft decision estimates.

**Table 7-3 Proposed vs draft decision total forecast opex (\$million 2014–15)**

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
JGN's proposal <sup>6</sup>	155.4	155.4	156.6	161.3	160.6	789.3
AER draft decision	154.4	153.8	154.6	159.0	157.8	779.7
Difference	-1.0	-1.5	-2.0	-2.3	-2.8	-9.6

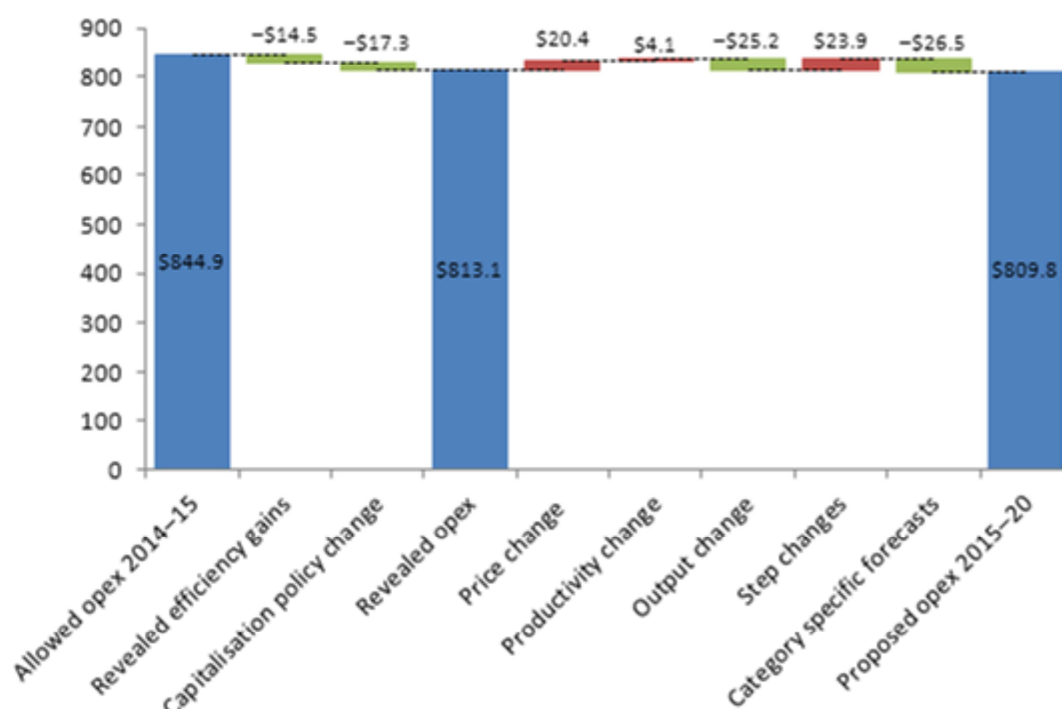
Source: AER analysis.

Note: Excludes debt raising costs.

### 7.5.1 Forecasting method

We have assessed JGN's forecast method to examine whether this explains why its forecast opex is higher than our alternative estimate. We are satisfied that JGN's forecasting method is not the key driver of the difference. The revenue impact of JGN's forecasting method is disaggregated in Figure 7.2. This figure shows the drivers of change between JGN's allowed opex in 2014–15 and its proposed opex allowance for the 2015–20 access arrangement period.

**Figure 7.2 Forecasting method impacts, \$million, 2014–15**



Source: AER analysis.

JGN describes its opex forecasting method in its access arrangement information.<sup>7</sup> JGN used two methods to forecast opex for the 2015–20 access arrangement period:

<sup>6</sup> Subsequent to JGN's access arrangement proposal, JGN updated its forecast opex to remove costs associated with the carbon tax, corrected an error in its Unaccounted for Gas forecast and provided an updated productivity growth estimate. This changed its forecast from \$797.5 million (\$2014-15) to \$789.3 million (\$2014-15).

1. the rate of change approach—applied to the adjusted base year opex amount, which excludes category-specific forecasts over the 2015–20 access arrangement period
2. category-specific forecasts—for four categories of costs.

## The rate of change approach

The rate of change component of JGN's opex forecast is similar to our own preferred method:

- JGN used revealed expenditure in 2013–14 as its base opex. This reduced its forecast opex by \$14.5 million compared to setting opex for each year of the 2015–20 access arrangement period equal to JGN's allowed opex for 2014–15. We have assessed JGN base opex in section 7.5.2.
- JGN removed expenditure from its base opex to reflect the capitalisation policy that will apply in the 2015–20 access arrangement period. This adjustment reduced JGN's opex forecast by \$17.3 million (\$2014–15).
- JGN has accounted for forecast price changes by applying forecast changes in labour and materials prices. The application of these forecast price changes increased JGN's opex forecast by \$20.4 million (\$2014–15). We have assessed the impact JGN's proposed forecast price changes in Appendix A.
- JGN's opex forecast accounted for changes in opex partial factor productivity forecast by Economic Insights.<sup>8</sup> These forecast productivity changes reduced JGN's opex forecast by \$4.1 million (\$2014–15). We have assessed the impact of these forecast productivity changes in Appendix A.
- JGN's forecasting method accounts for forecast changes in output. Forecast output change decreased JGN's opex forecast by \$25.2 million (\$2014–15). We have assessed the impact of JGN's proposed output growth in Appendix A.
- JGN's forecasting method includes the addition of step changes for 'increases or decreases in costs due to new regulatory obligations, changes in good industry practice and JGN's operating environment'.<sup>9</sup> Our preferred approach allows for step changes when efficient opex, required to meet the opex criteria, is not captured in base opex or the rate of change.<sup>10</sup> These step changes increased JGN's opex forecast by \$23.9 million (\$2014–15). We have assessed these proposed step changes in section 7.5.4.

## Category-specific forecasts

JGN developed specific forecasts for four categories of opex:

- government levies
- unaccounted for gas
- carbon costs
- debt raising costs.

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<sup>7</sup> JGN, *2015-20 Access Arrangement Information*, 30 June 2014, pp. 77–78.

<sup>8</sup> JGN, *2015-20 Access Arrangement Information*, 30 June 2014, pp. 76–77.

<sup>9</sup> JGN, *2015-20 Access Arrangement Information*, 30 June 2014, p. 76.

<sup>10</sup> AER, *Expenditure forecast assessment guideline for electricity transmission*, November 2013, p. 24.

Excluding these categories of opex reduced JGN's opex forecast by \$26.5 million (2014–15) compared to leaving these costs in the base. Despite our broad concerns with hybrid forecasting approaches in some instances,<sup>11</sup> in this instance we are satisfied JGN forecasting approach does not produce opex forecasts that exceed the efficient level of expenditure required by JGN to meet the opex objectives.

For the first three of these cost categories, if actual opex is different to the approved forecast, subject to the tariff variation mechanism, JGN may be able to pass-through the changes to network prices. Consequently, in order to implement any changes to tariffs we need to set a forecast amount for these categories. We discuss JGN's tariff variation mechanism in attachment 11.

The fourth cost category, debt raising costs, has been forecast using our standard forecasting approach for this category that sets forecasts equal to the costs incurred by a benchmark firm.

## 7.5.2 Base year opex

We are satisfied JGN's proposed 2013–14 base year expenditure of \$133.2 million (\$2014–15) is a reasonable estimate for the purpose of forecasting opex for the 2015–20 access arrangement period.

Typically, where a service provider is subject to an incentive mechanism we are satisfied it does not have an incentive to increase its opex in the proposed base year. JGN is not subject to an incentive mechanism in the current access arrangement period. Without an incentive mechanism in place, JGN has an incentive to increase opex in the proposed base year. Under our forecasting approach, an increase in base year opex will mean a higher forecast opex for the access arrangement period. Given this factor, we have assessed whether the proposed base year opex includes any increases or one-off costs, not reflective of recurrent efficient opex. However, we have found no evidence of this in JGN's opex in 2013–14.

Unlike with the electricity network service providers, we do not have standardised data across the gas network service providers in order to be able to conduct our own economic benchmarking or category analysis to assess the efficiency of the revealed base year.<sup>12</sup> Instead, we are primarily relying upon analysis of JGN's historical trends and the output from the gas NSP productivity work which JGN submitted as part of its regulatory proposal. In doing so, we have tested, to some extent, the robustness of this model and the underlying data used to produce its outputs. We consider there is no evidence to suggest that JGN's revealed costs in its proposed base year are materially inefficient.

### Which year should be used as the base year?

JGN chose 2013–14 as its base year. JGN proposed adjustments to remove non-recurrent costs to reflect changes in cost treatments and to remove the expenditures forecast on a category-specific basis.<sup>13</sup> JGN's adjustments reduce its base opex to \$133.2 million (\$2014–15).

We consider that JGN's proposed base year is a reasonable base year for forecasting opex for the following reasons:

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<sup>11</sup> Generally it is best to use the same forecasting approach for all cost categories of opex because hybrid forecasting approaches often produce biased opex forecasts inconsistent with the opex criteria. Using one approach for some cost categories can invalidate the use of another approach for the other categories. For example, the forecast of total opex will systematically exceed the efficient level of opex if a bottom up forecasting approach is used to forecast opex categories with low expenditure in the base year, or with a greater rate of change than total opex.

<sup>12</sup> We are unable to perform any reliable benchmarking analysis as we do not have a standardised set of data from the GDBs.

<sup>13</sup> JGN, *2015–20 Access arrangement information*, Appendix 7.2, June 2014 pp. 7–8, 17.

- As many opex items are of a recurrent nature, actual costs incurred in 2013–14 are likely be a good indicator for the efficient costs to be incurred in the 2015–20 access arrangement period.
- 2013–14 is the second last year of the current access arrangement period. The second last year is usually the most recent available at the time of our final determination. To the extent expenditure drivers do not change over time, this year is likely to best reflect expenditure in the forecast period.
- JGN's adjusted opex is relatively stable across the access arrangement period. For instance opex in 2013–14 is not significantly different from the equivalent opex in 2010–11 and 2011–12 (Figure 7.1). JGN's adjusted opex in 2013–14 is the second lowest of the access arrangement period. This indicates that JGN has not incurred opex in this year to try and increase its opex forecasts for the 2015–20 period.
- Although JGN has overspent its allowance in the first four years of the current access arrangement period compared to our original forecast, this overspend can be attributed to the introduction of carbon costs, and to unaccounted for gas, which was greater than forecast.<sup>14</sup> The AER approved pass-throughs totalling \$15.8 million (\$2014–15) for JGN to recover these costs from customers.<sup>15</sup> Once pass through amounts are accounted for, JGN has underspent all allowed opex by 1.29 per cent over the first four years of the current access arrangement period. This indicates that JGN is likely responding to the cost minimisation/profit maximisation incentives of the framework.
- We did not find any further evidence of non-recurrent expenditure in JGN's proposed adjusted base year, once the non-recurrent expenditure that JGN identified had been removed.

Based on our above factors we are satisfied that JGN's proposed base year (2013–14) is not biased upwards and there is no evidence to suggest that expenditure in the proposed base year is materially inefficient.

We also considered benchmarking undertaken by Economic Insights, which was engaged by JGN to support the efficiency of its base year opex. Economics Insights concludes that JGN's opex is not on the frontier for the benchmarking period covered (i.e., 1999 to 2013); however it considers this is likely to reflect differences in the scope of activities undertaken by businesses that have not been accounted for.<sup>16</sup>

In considering the findings of this report, we have observed some limitations that may affect the robustness of the benchmarking. For instance:

- The data set uses regulatory information that is available in the public domain for all businesses other than JGN. Data extracted from a mix of sources, particularly financial information such as opex, may not necessarily be reported consistently over time and across gas distribution businesses.
- Although two New Zealand gas distribution businesses were added to the data to improve the robustness of the data set, there was relatively limited cross-sectional variation included in the data set.

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<sup>14</sup> The allowance for carbon costs is \$0 in the current access arrangement period; see AER, *Access arrangement information for the access arrangement, JGN's NSW gas distribution networks 1 July 2010 – 30 June 2015*, 26 September 2011, p. 11.

<sup>15</sup> AER, *Decision - JGN (NSW) cost pass through event application*, May 2013, p. 3.

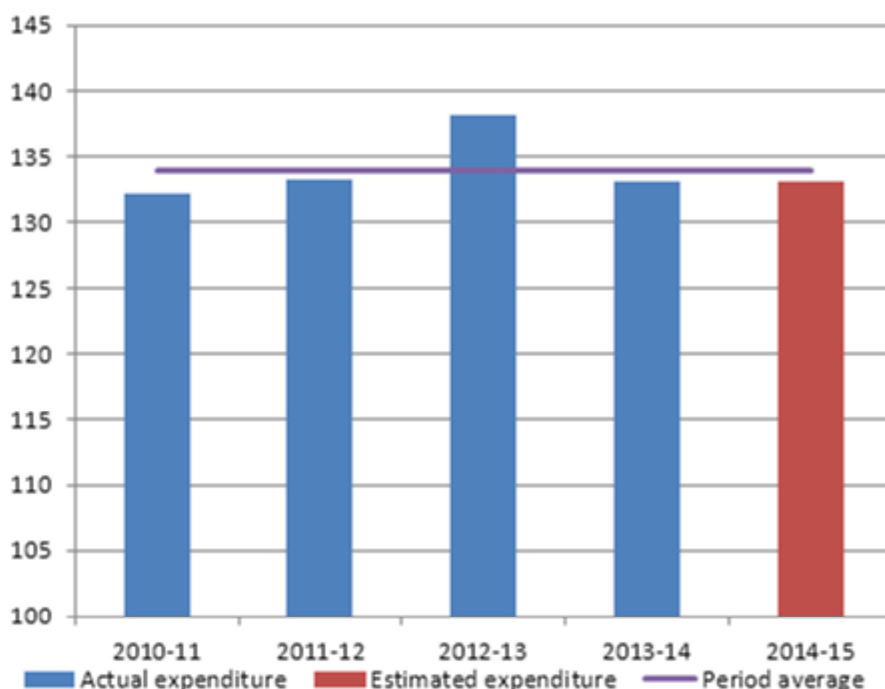


- The forecast and regulatory proposal data are used for gas distribution businesses other than JGN where actual data is not available. This may be different to what was realised which could affect the benchmarking results.
- We consider there could be further sensitivity analysis undertaken to demonstrate the robustness of the model specification adopted by JGN.

On this basis, we consider this evidence is inconclusive as to whether JGN's historical opex is efficient.

We also note the Consumer Challenge Panel (CCP) suggested we review adjustments to the opex base year due to the transfer of pigging, integrity digs and adhoc mains renewal costs from opex to capex.<sup>17</sup> We reviewed JGN's opex modelling and are satisfied that JGN has removed the entirety of these expenditures from its base year.

**Figure 7.3 JGN's opex minus adjustments, 2010–11 to 2014–15 (\$million, 2014–15)**



Source: JGN, 2015–20 Access arrangement information, Appendix 7.1.

Note: JGN's adjustments to their base opex include the removal of one-off expenditures (\$0.27m), removal of expenditures due to differences in treatment between access arrangement periods (\$3.47m) and removal of the expenditures that JGN has forecast using a category specific forecast (\$29.45m). See JGN, 2015–20 Access arrangement, Appendix 7.2, June 2014, pp. 7–8, 17.

### 7.5.3 Rate of change

Once we have determined the efficient base level of opex in the 2009–14 access arrangement period we apply a forecast annual rate of change to forecast opex for the 2015–20 access arrangement period. The rate of change is forecast as:

$$\Delta Opex = \Delta price + \Delta output - \Delta productivity$$

<sup>17</sup> Consumer Challenge Panel sub-panel 7, *Submission to JGN's access arrangement proposal for 2015–20*, September 2014, p. 10.

Where  $\Delta$  denotes the proportional change in a variable.

The rate of change captures the year on year change in efficient expenditure. Specifically it accounts for forecast changes in outputs, prices and productivity (such as economies of scale). These three opex drivers should explain all changes in efficient opex. The output and productivity change variables capture the forecast change in the inputs required. The real price change variable captures the forecast change in the prices of those inputs.

JGN has adopted our preferred rate of change methodology for estimating its proposed opex rate of change. We have therefore assessed the inputs that JGN has applied in forecasting its rate of change.

We consider JGN's proposed output change and productivity change estimate to be reasonable.

However, we are not satisfied with the following aspects of JGN's forecast price changes:

- the higher percentage of labour as a proportion of opex in the forecast period is inconsistent with the labour and non-labour proportions used in Economic Insights' analysis. Since labour price is increasing at a greater rate than CPI, a higher proportion of labour will result in a rate of change that is higher than using Economic Insights' weightings.
- analysis we have previously undertaken suggests that BIS Shrapnel's labour forecast is less accurate than a forecast based on average BIS Shrapnel and DAE's labour forecasts for the EGWWS industry.
- JGN has not demonstrated a relationship between the change in the price of materials and the change in its total opex.

For these reasons we are not satisfied that JGN's forecast of price changes is the best estimate possible in the circumstances. Therefore, we are not satisfied that including JGN's forecast in our forecast of total opex would satisfy the opex criteria. Our detailed assessment of JGN's rate of change is in Appendix A.

**Table 7-4 Forecast rate of change—JGN (per cent)**

	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20
<b>JGN's proposal</b>						
Input price change	0.47	0.92	1.19	1.25	1.15	1.32
Output change	-4.72	-0.31	0.52	0.38	0.37	0.48
Opex partial factor productivity	-2.71	0.25	0.96	0.85	1.25	1.46
<b>Opex rate of change</b>	<b>-1.67</b>	<b>0.36</b>	<b>0.74</b>	<b>0.77</b>	<b>0.26</b>	<b>0.32</b>
<b>AER draft decision</b>						
Input price change	0.49	0.47	0.76	0.89	0.89	0.92

Output change	-4.72	-0.31	0.52	0.38	0.37	0.48
Opex partial factor productivity	-2.71	0.25	0.96	0.85	1.25	1.46
<b>Opex rate of change</b>	<b>-1.65</b>	<b>-0.10</b>	<b>0.31</b>	<b>0.42</b>	<b>0.00</b>	<b>-0.07</b>
<b>Difference</b>	<b>0.02</b>	<b>-0.46</b>	<b>-0.43</b>	<b>-0.36</b>	<b>-0.26</b>	<b>-0.39</b>

Source: JGN, Appendix 7.1, JGN opex forecast model (Updated), October 2014; AER analysis.

## 7.5.4 Step changes

In some instances, a service provider may face a step change in efficient costs that is not reflected in the base year or rate of change for the access arrangement period. Our assessment of step changes is made in the context of our assessment of the service provider's total forecast opex. When assessing a service provider's proposed step changes, we consider whether without those changes, total opex would comply with the opex criteria.

As a starting point, we consider whether the proposed step changes in opex are already compensated through other elements of our opex forecast, such as the base efficient opex or the 'rate of change' component. Step changes should not double count costs included in other elements of the opex forecast.

Further to assessing whether step changes are captured in other elements of the opex forecast, we assess the reasons for, and the efficient level of, the incremental costs the service provider has proposed.

One important consideration is whether each proposed step change is driven by an external obligation (such as new legislation or regulations) or an internal management decision (such as a decision to increase maintenance opex). Step changes should generally relate to:

- a new obligation or some change in the service provider's operating environment beyond its control, or
- an efficient trade-off with costs that are recovered elsewhere in a service provider's regulated revenue – such as capex.

Other changes in opex can generally be funded through a base level of opex.

JGN proposed six step changes totalling \$24 million (\$2014–15). We assessed JGN's proposed to step changes to determine whether these should be included in our total opex forecast. Table 7-5 sets out JGN's proposed step changes and our position on those step changes. We give the reasons for our draft decision for each step changes below.

**Table 7-5 JGN proposed step changes and our position (\$million, 2014–15)**

Proposed step change	Amount	Draft decision allowance	Reasons for draft decision
NECF	6.4	6.4	New regulatory obligation
Customer engagement	0.5	0.5	Capitalisation policy change

Reset costs	7.9	7.9	Capitalisation policy change
Annual regulatory reporting	1.9	–	Not a new regulatory obligation
Marketing	6.6	6.6	Efficient response to change in market conditions.
Insurance premiums	0.6	0.6	Prudent change in risk management
<b>Total step changes</b>	<b>23.9</b>	<b>22.0</b>	

Source: JGN, *Access Arrangement Information*, June 2014, p. 76.

## National Energy Customer Framework

JGN proposed a step change of \$6.4 million to comply with the National Energy Customer Framework (NECF) from 1 July 2015.<sup>18</sup> We have included this step change in our opex forecast because it is driven by a change in JGN's regulatory obligations and the costs are not captured in base year expenditure. We had regard to the supporting information JGN provided and we assessed the underlying assumptions of the forecast cost of complying with the NECF. We consider that the assumptions and method JGN used to forecast the opex step change is reasonable.

The NECF governs the rights, obligations and consumer protections with respect to the retailer-customer relationship and distributor-customer relationship. Under the NECF, JGN has a direct contractual relationship with gas consumers, whereas previously retailers provided the interface between JGN and customers. Specifically, under the NECF:

- customers can seek a range of retail support services directly from JGN that are currently performed by, or administered through, gas retailers
- householders, in addition to builders and developers, can make connection applications directly to JGN rather than via retailers. Further, JGN consider they will not be able to charge connection applicants an administration fee where currently they are able to.

As a consequence of the commencement of full NECF, JGN expects a significant volume of enquiries and service requests to come directly from customers from 1 July 2015. It stated that it must develop and implement a range of system and process changes and employ more staff to receive and respond to the additional requests in compliance with NECF requirements.<sup>19</sup>

JGN forecast the increased staff needed to provide customer support and billing services that were previously performed by gas retailers. It did this by multiplying the expected increase in call numbers and billing load by the productivity of existing call centre and billing staff. We consider this approach is reasonable because it is based on JGN's historical costs in providing call centre and billing services. There is no evidence that JGN's historical costs are inefficient.

JGN proposed that a second consequence of the commencement of the full NECF is that it will bear the cost of assessing and processing connection applications from residential customers as well as from builders and developers. JGN forecast the cost of processing the additional connection

<sup>18</sup> The NECF was implemented in NSW from 1 July 2013 in transitional form, with JGN required to comply with full NECF requirements by 1 July 2015.

<sup>19</sup> JGN, *Access arrangement information*, p. 11.

applications by multiplying the expected increase in the volume of applications by the additional FTEs needed to service the increase in applications.

- JGN based its volume assumptions on its forecast share of all connection applications. JGN estimated its market share of direct connection customers (i.e. customers who place their connection applications directly with JGN instead of with a retailer) would increase to 80 per cent of all applications by 2017–18 as a result of complying with the full NECF obligations. It based this forecast on its market share (60 per cent in 2010–11) when JGN introduced the Connect Direct service for commercial connections. JGN also stated that under the full NECF it will no longer be able to charge application fees (currently \$220 for residential connections and \$550 for commercial connections) and that this will attract significantly more direct connection customers.
- JGN based its forecast costs on the actual cost of assessing and processing connection applications in 2013–14.

We consider that the assumptions and method JGN used to forecast the costs of processing direct connection applications are reasonable. As this is also a new obligation, we have included JGN's forecast in our alternative opex forecast.

The Energy Markets Reform Forum (EMRF) submitted that customer support should be considered a normal part of a network's business and saw no basis for additional cost recovery in this area.<sup>20</sup> It recommended we apply a consistent approach to assessing these costs across all service providers. We agree that most customer support costs are reflected in a service provider's base year costs and do not require a step change. However, where there is an increased regulatory obligation, we consider the service provider should be able to recover the efficient incremental costs of meeting the increased obligation.

## Customer engagement

JGN proposed an increase in opex of \$0.5 million for customer engagement which we have included in our forecast of total opex.

JGN stated that it established its Customer Council to assist it in understanding its customers and stakeholders and to guide its decision making for its 2015 Plan and issues in the future. JGN stated the council comprises a diverse set of customer and stakeholder advocates that represents JGN's residential, small business and large industrial customer base as well as its key stakeholders. JGN also proposed two market research studies to evaluate customer satisfaction with its service performance and engagement strategies. The studies are to include surveying business and residential customers (on-line/telephone surveys), deliberative forums held in both metropolitan and regional locations and interviews with self-contracting users, industrial customers and retailers.

JGN first established its Customer Council in the 2013–14 base year. In this year JGN also:

- undertook a series of deliberative forums with residential and small business customers
- interviewed 14 of its largest industrial customers
- held round table discussions with energy retailers and self-contracting customers

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<sup>20</sup> EMRF, *Submission to JGN's access arrangement proposal for 2015–20*, 1 September 2014, p. 48.

- conducted one on one discussions with each market participant including energy intermediaries, AEMO, AEMC, AER, IPART and NSW Government.<sup>21</sup>

We have included these costs because while JGN incurred consumer engagement costs in 2013–14 they were recorded as capex not opex. As a result, they are not included in our base opex forecast. Customer engagement costs represent ongoing costs incurred in operating a network business, therefore we consider they are best treated as opex rather than capex. We consider the amount proposed by JGN is relatively modest.

We also note that the CCP found that JGN has demonstrated a genuine commitment to customer engagement as part of the process of developing its proposed 2015–20 access arrangement and that the level of expenditure was fairly modest.<sup>22</sup>

## Reset costs

We have included a step change for JGN's 2015–20 access arrangement reset costs in our forecast of total opex. As with customer engagement costs, these costs were previously treated as capex rather than opex. As these costs represent ongoing costs incurred in operating a gas network we consider these costs are better treated as opex than capex. We are also satisfied the amount JGN proposed reasonably reflects the cost of preparing a regulatory proposal.

The costs JGN incurred to prepare its access arrangement proposal for 2010–15 were treated as capex. However, in that determination we stated that in general costs associated with the preparation of a regulatory proposal are opex and will not be accepted as capitalised regulatory costs in future access arrangement proposals.<sup>23</sup>

In its submission the Energy Markets Reform Forum (EMRF) noted that the costs for the next reset are significant and that more effort should be made to reduce these costs. The EMRF also noted that networks are consistently and significantly increasing the costs for their revenue resets over time.<sup>24</sup>

We consider the amount JGN proposed to prepare its 2020 access arrangement proposal is reasonable. This is because JGN based its forecast on the costs it incurred or expects to incur to prepare this proposal and because they are broadly comparable with the costs other gas pipeline service providers required to prepare their access arrangement proposals.<sup>25</sup> We note that service providers do face an incentive to reduce all opex costs over time, including reset costs, due to our incentive framework.

## Annual regulatory reporting

JGN proposed a step change of \$1.9 million for the costs of anticipated increased regulatory reporting obligations. JGN stated that it anticipates its AER annual regulatory reporting obligations will increase to a level comparable to that of Jemena's electricity network annual reporting obligations.<sup>26</sup>

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<sup>21</sup> Source: <http://jemena.com.au/Gas/getattachment/Customer-Engagement-and-Price-Review/Engaging-with-the-community/Background-Gas-pricing-and-economic-regulation/JGN-Customer-Council-Fact-Sheet-Our-engagement-around-the-2015-Plan.pdf.aspx>, 31 May 2014.

<sup>22</sup> CCP, subpanel 7, *Advice on JGN's access arrangement proposal 2015-20*, 3 September 2014, 3 September 2014, pp. 2, 3-6.

<sup>23</sup> AER, *Jemena Gas Networks Access arrangement proposal for the NSW gas networks 1 July 2010 – 30 June 2015*, June 2010, p. 43.

<sup>24</sup> EMRF, *Submission to JGN's access arrangement proposal for 2015–20*, 1 September 2014, p. 48.

<sup>25</sup> We compared JGN's proposed costs to the regulatory costs proposed by Envestra and SP AusNet in the most recent VicGAAR access arrangement.

<sup>26</sup> JGN, *2015–20 Access arrangement information*, June 2014, Attachment 7.3 Opex step changes report, p. 23.

JGN's assumption that we will significantly escalate our annual reporting requirements from 2015–16 onwards is incorrect. Our better regulation guidelines and associated regulatory reporting notices apply to electricity and do not apply to gas. Further, there is no proposed gas rule change to mirror the recent changes in the electricity rules. As such there is no expectation of a step change from existing reporting obligations. Therefore, we have not included JGN's proposed step change for annual regulatory reporting in our forecast of total opex.

## Marketing

JGN proposed a \$6.6 million marketing step change to increase its marketing program and to promote the sale of gas appliances via incentive payments. We have included JGN's marketing step change in our forecast of total opex.

JGN considers natural gas to be a fuel of choice in NSW which competes with electricity and other fuels. JGN's marketing program aims to attract new customers and encourage them to purchase additional natural gas appliances. The rebates are intended to reduce the barriers to connecting/using natural gas created by the upfront costs of purchasing and installing new natural gas appliances.<sup>27</sup>

In the 2015–20 access arrangement period JGN expects market conditions to deteriorate for several reasons, including rising gas wholesale prices and declining electricity wholesale prices. JGN proposes to address this by expanding the scope and scale of the incentive rebate scheme. It proposes to do this by:

- increasing the incentive rebates payable on whole of house (WOH) heating, hot water systems and flued heating
- introducing an incentive rebate for unflued heating
- introducing a \$300 incentive payment to dealers where an appliance sale results in new electricity to gas connection
- increasing the number of campaigns run per year
- introducing a program for vulnerable customers including a no interest loan scheme.

The proposed step change of \$6.6 million represents a 16 per cent increase in JGN's marketing expenditure, increasing it to \$45 million for the access arrangement period.<sup>28</sup> Of this, JGN proposed spending \$25 million on the rebate scheme. The forecast increased demand attributable to the increased marketing campaign has been included in JGN's demand forecasts.

The CCP asked us to consider whether the marketing expenditure was prudent. That is, whether it is prudent to encourage new customers to connect to the gas network, and existing customers to install more gas appliances, at a time when wholesale gas prices, and hence retail gas prices are predicted to rise substantially.<sup>29</sup> The ERMF also questioned whether the entire marketing proposal was sufficiently supported by evidence of a net benefit to consumers' long term interests.<sup>30</sup> JGN

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<sup>27</sup> JGN, *2015–20 Access arrangement information*, June 2014, Attachment 7.3 Opex step changes report, p. 11

<sup>28</sup> JGN, *2015–20 Access arrangement information*, June 2014, *Attachment 7.3 Opex step changes report*, Table 5.2, p. 15.

<sup>29</sup> CCP, subpanel 7, *Advice on JGN's access arrangement proposal 2015-20*, 3 September 2014, p. 10.

<sup>30</sup> ERMF, *Submission to JGN's access arrangement proposal for 2015–20*, 1 September 2014, p. 48.



responded that increasing the number of customers efficiently connecting to its network is in the long-term interests of customers of natural gas and required by the national gas objective.<sup>31</sup>

Marketing expenditure can be an efficient response by a service provider to changes in market conditions. JGN provided a cost benefit analysis to demonstrate that it expected the marketing step change would generate a net benefit over fifteen years. Its main assumptions underlying the analysis related to the forecast increase in sales of gas appliances attributed to the program. It forecast that increased sales of gas appliances would lead to increased gas consumption over the life of each appliance sold.

We requested further information so we could test JGN's assumptions about the assumed growth in sales of WOH, flued heating and hot water systems in the current period; the assumed sales of unflued heaters; and the take-up rates of the rebate scheme. We note that Origin Energy submitted that it considers JGN's assumptions about the rate of new connections and the rate of electricity to gas conversions as a result of its marketing are too high.<sup>32</sup>

JGN based its assumed 29 per cent growth in sales of WOH, flued heating and hot water systems on the actual growth in appliance sales (27 per cent) generated by its rebate campaign between 2011–13. Because JGN has not previously offered a rebate for unflued natural gas heating, it assumed a similar increase in sales to that of flued heating. JGN also assumed no growth in appliance sales over the 2015–20 access arrangement period because of the expected downturn in the market. It based its assumptions for the expected rebate take-up rates on the historical take up rates of its existing rebate scheme. Because these assumptions are generally based on JGN's historical experience in implementing a rebate program we consider them to be reasonable. As a result, we are satisfied JGN provided sufficient justification to support the assumptions that underlie the expected positive benefit cost result. We are therefore satisfied that this program reflects efficient expenditure.

In assessing this proposal, we have also considered whether this step change could be self-financing. That is, we considered whether the expected additional revenue the project would generate for JGN without an approved increase in opex would be sufficient to fund the step change.

However, we consider it is unlikely that this would be the case. Forecast increased demand in the 2015–20 access arrangement period attributable to the marketing campaign is already reflected in JGN's demand forecasts and therefore will be reflected in JGN's reference tariffs for this period. In the access arrangement period beginning in 2020 we will set new reference tariffs. In all likelihood we would expect that gas consumption in 2015–20 will be given significant weight in forecasting demand from 2020. Some of this demand will be attributable to JGN's marketing campaign. We would therefore expect that any long term increases in demand as a result of JGN's marketing campaign will also continue to flow through to the regulated price(s) JGN's consumers face from 2020.

## Insurance premiums

JGN proposed a step change of \$0.6 million for insurance premiums not included in base year expenditure. We have included the step change in our forecast of total opex because we consider the insurance reflects a prudent and efficient risk management practice. Our analysis of the step change is included in a confidential appendix due to the commercially sensitive nature of the information.

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<sup>31</sup> JGN, *Response to the advice from the Consumer Challenge Panel*, 19 September 2014, p. 21.

<sup>32</sup> Origin Energy, *Submission to JGN's access arrangement proposal for 2015–20*, 25 August 2014, pp. 7–8.



### 7.5.5 Other forecast opex

JGN proposed category-specific forecasts for four opex cost categories:

- government levies
- unaccounted for gas
- carbon costs
- debt raising costs

We have included JGN's forecast for government levies, unaccounted for gas and carbon costs in our opex forecast. A comparison of JGN's forecast and our draft decision is outlined below in Table 7-6.

Our assessment approach for debt raising costs and the reasons for our forecasts are set out in the debt and equity raising costs appendix.

**Table 7-6 JGN forecast of other opex and our draft decision (\$million, 2014-15)**

Forecast of other opex	Forecast opex for 2015–20	Draft decision allowance
Government levies	21.0	21.0
Unaccounted for gas	79.0	79.0
Carbon costs	0.2	0.2

Source: JGN, *Access Arrangement Information*, June 2014, p. 79.

#### Government levies

JGN pays annual pipeline licence fees to the NSW Department of Trade and Investment and Regional Services (DTIRIS) and to the Independent Pricing and Regulatory Tribunal. It has little control over these costs.

We have included JGN's forecast government levies in our forecast of total opex. JGN's forecast government levies is the same as the levies it incurred in 2013–14. We consider a forecast based on JGN's historical levies incurred to be reasonable forecasting approach. We note that any changes in the annual levies charged will be adjusted in accordance with JGN's tariff variation mechanism.

#### Unaccounted for gas

Unaccounted for gas (UAG) refers to any gas lost or unaccounted for while it is in JGN's custody. It is calculated as the difference between the measured quantity of gas entering the network system (receipts) and metered gas deliveries (withdrawals). JGN is required to replace any unaccounted for gas, which it buys through a competitive tender process.<sup>33</sup>

<sup>33</sup> JGN, *Reference Service Agreement - JGN's NSW gas distribution network*, 30 June 2014, p. 31

JGN's access arrangement includes an incentive to minimise the rate of UAG. If the actual UAG rate is below (above) JGN's target UAG rate, JGN over (under) recovers its actual UAG costs.<sup>34</sup> If actual market volumes or the cost of purchasing UAG differs from the approved forecast, JGN is compensated through the tariff variation mechanism.

We have included JGN's forecast opex associated with replacing UAG in our forecast of total opex as set out in Table 7-6. However, we note the final UAG forecast we include in our opex forecast will need to reflect the final demand forecast we approve. We discuss our draft decision on JGN's demand in attachment 6.

JGN is provided a fixed allowance for a quantity of UAG based on a target percentage rate of total network receipts. The UAG allowance is the product of:

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

We consider JGN's forecast is based on reasonable assumptions regarding the approved target rate of UAG and the cost of replacement gas. However, we consider JGN's assumption regarding total gas receipts, or demand, is too low.<sup>35</sup> We assess each of the three assumptions in more detail below.

### **Target rate of UAG**

In the 2010–15 access arrangement period JGN's target UAG rate was based on a single benchmark rate of 2.34 per cent of receipts. However, JGN proposed a different approach for the 2015–20 access arrangement period.

For the 2015–20 access arrangement period JGN proposed we use dual UAG benchmarks to forecast its UAG: one benchmark for its non-daily metered customers (residential and small commercial) and another for its daily metered customers (larger, industrial customers). JGN proposed we use the following UAG rates for the two market segments:

- 5.44 per cent of forecast withdrawals for the non-daily metered market
- 0.45 per cent of forecast withdrawals for the daily metered market.

JGN considered 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. JGN considered this supports the allocation of a higher UAG rate to daily metered customers and a lower UAG rate to non-daily metered customers. As it expects industrial demand for gas to decline relative to residential demand, it considered a single benchmark based on historical UAG would underestimate the likely UAG over the period.

The EMRF recommended that we consider JGN's proposal favourably, but it submitted we should require JGN to undertake and share further analysis of the costs and benefits of two separate UAGs

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<sup>34</sup> JGN is compensated for changes in total market volumes and costs of purchasing UAG through the tariff variation mechanism.

<sup>35</sup> See clauses 9.4, 9.5(d) and 9.5(e) of the Reference Agreement.

and the impact on network tariffs to different customer classes.<sup>36</sup> Both the ERMF and Lumo Energy considered that future UAG targets should reflect any reduction that would come from the final stages of replacing cast iron mains with plastic.<sup>37</sup>

We are satisfied that JGN has demonstrated that the UAG rate for non-daily metered deliveries is higher than the UAG rate for daily metered deliveries. JGN provided the following information in support of different UAG rates:

- the low and medium gas mains system providing non-daily metered customers is ten times longer than the high pressure system supplying daily metered customers.
- whereas certain leakage levels can be safely managed on medium and low pressure systems, losses must be avoided on high pressure systems in order to maintain safe and reliable operations.
- metering design and maintenance for daily metered customer delivery points is carried out to a higher level of engineering standards.
- Because of the higher potential consequences of a gas escape from a high pressure main, additional preventative measures are applied to high pressure assets to avoid damage from third party interference.
- the ESC applied a similar dual rate approach in Victoria and the ratios between the rates used by the ESC are of a similar magnitude for the Victorian pipeline service providers.<sup>38</sup>

We are satisfied that there is likely to be different rates of leakage depending on whether gas is supplied through high pressure systems or medium to low pressure systems. Therefore, we agree that using dual targets will provide a better forecast of future UAG in a period in which large customer demand is expected to change relative to the benchmark period. Using a single historical rate may underestimate the UAG to occur in the forecast period.

Having accepted JGN's proposal that the UAG rates are likely to be different between the non-daily metered and the daily metered markets, we assessed if JGN's proposed targets for each market are reasonable.

Total UAG and the level attributable to each market cannot be observed and must be estimated.<sup>39</sup> JGN's approach to determining total UAG rate and the level attributable to each market was to:

- estimate the total UAG target rate as the average historical UAG rate over the last five years (2009–2013)<sup>40</sup>
- split the UAG into the two components contributed by the two market segments using regression analysis to determine which pair of dual targets best fit the available data.

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<sup>36</sup> ERMF, *Submission to JGN's access arrangement proposal for 2015–20*, 1 September 2014, p. 45.

<sup>37</sup> Lumo Energy, *Submission to JGN's access arrangement proposal for 2015–20*, 28 August 2014.

<sup>38</sup> Essential Services Commission Victoria, *Gas Distribution Code, Review of Unaccounted for Gas Benchmarks, Final Decision*, June 2013, p. 4.

<sup>39</sup> Even then, UAG is not directly observed and needs to be estimated as the residual of receipts less the amount billed to daily metered customers and the estimate of the amount billed to non-daily metered customers. The quantity of actual non-daily metered withdrawals is not known because household meters are measured infrequently and not across a common time period.

<sup>40</sup> JGN used five years of monthly estimates of UAG.

JGN determined a total UAG rate of 2.24 per cent using five years of average historical UAG rates. We consider using the historical five year average as the benchmark value for setting the UAG allowance is a sound approach. Because JGN faced an incentive to reduce its UAG in the 2010–15 access arrangement period, we consider it is reasonable to assume that this rate of UAG is an efficient rate of total UAG based on the market conditions in the 2010–15 access arrangement period. We also note that the proposed single UAG rate of 2.24 per cent for the 2015–20 access arrangement period is less than the target UAG rate of 2.34 per cent we approved for the 2010–15 access arrangement period.

JGN engaged Frontier Economics to examine the procedure it used to obtain separate estimates for the UAG rates for the two market segments. In Frontier's opinion, JGN's procedure was sound and appropriate for regulatory purposes.<sup>41</sup> However, Frontier suggested an alternative approach to overcome a problem with endogeneity and applied it to obtain alternative estimates of the UAG rates. JGN subsequently adopted Frontier's alternative estimates in its proposal. Frontier also found that JGN's approach ensured that the estimated segment-level UAG rates were consistent with the five year average total UAG rate. Frontier was concerned that the estimated UAG rates were sensitive to the length of the period chosen but found there was no other data sources that could be used to overcome this problem.

We tested Frontier's regression analysis and conclusions and we are satisfied with its method and findings. On this basis we are satisfied with the UAG rates JGN used to calculate its forecast.

### **Total gas receipts**

Because the forecast cost of UAG is the product of the approved target rate of UAG, total gas receipts, and the cost of the replacement gas, JGN's forecast UAG cost is directly related to its forecast demand. JGN based its forecast demand on Core Energy's report on gas demand and customer forecasts.<sup>42</sup> We assess JGN's forecast demand for the 2015–20 access arrangement period in attachment 6. In that section we consider JGN's demand forecast is too low. While we have included JGN's proposed opex for replacing UAG in our forecast of total opex in this draft decision, the UAG forecast we include in our final decision will reflect the final demand forecast we approve.

### **The cost of replacement gas**

JGN's forecast UAG cost is also directly related to JGN's forecast for the replacement cost of gas. JGN's forecast UAG prices are based on the current gas prices JGN pays for UAG as a result of its 2013 annual tender.<sup>43</sup> We consider this approach is sound and note that the actual cost of replacement gas will be submitted each year as part of the tariff variation process (along with the volumes received).

### **Carbon costs**

JGN forecast some costs in its proposal for auditing carbon costs. Under the *National Greenhouse and Energy Reporting Act*, JGN still reports its assumed fugitive emissions in each year.

These costs are a relatively modest amount and are based on JGN's historical costs. As such we have included them in our alternative opex forecast.

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<sup>41</sup> JGN, *Access arrangement information*, Appendix 7.6, UAG - Frontier Economics report, June 2014, p. 10.

<sup>42</sup> JGN, *2015–20 Access arrangement information*, Appendix 5.1, Core Energy, Gas demand and customer forecasts, April 2014.

<sup>43</sup> JGN, *Access arrangement information*, p. 133.

## 7.6 Revisions

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

**Revision 7.1:** Make all necessary amendments to reflect our draft decision on the proposed opex allowances for the 2015–20 access arrangement period, as set out in Table 7-1.

## A Appendix: Rate of change

This appendix contains our assessment of the opex rate of change for use in developing our alternative forecast of total opex. We apply the rate of change to our base opex to derive an opex forecast that includes forecast changes in input prices, output and productivity for the 2015–20 access arrangement period. We set out that we would develop an opex forecast incorporating the rate of change in our *Expenditure forecast assessment guideline* for electricity.<sup>44</sup> We have adopted the same rate of change methodology for assessing JGN's proposed rate of change.

### A.1 Position

Overall we are not satisfied that JGN's rate of change reflects the opex criteria and the criteria for forecasts and estimates.<sup>45</sup> This is driven by differences between JGN's and our forecast price change.

For the purposes of the draft decision we have adopted JGN's forecast output and productivity change. However, we consider JGN's revised proposal should reflect updated labour price and demand data.

Further, we note several issues with JGN's application of the opex cost function to forecast productivity.

These issues are discussed below.

JGN's and our forecast rate of change for the 2015–20 access arrangement period is outlined in Table 7-7.

We note Economic Insights provided an updated version of its opex productivity analysis.<sup>46</sup> We have applied the output change and opex partial factor productivity figures from this updated report.

**Table 7-7 JGN and AER rate of change (per cent)**

	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20
JGN	-1.67	0.36	0.74	0.77	0.26	0.32
AER	-1.65	-0.10	0.31	0.42	-0.00	-0.07
<b>Difference</b>	0.02	-0.46	-0.43	-0.36	-0.26	-0.39

Source: AER analysis.

### A.2 Proposal

JGN commissioned Economic Insights to calculate JGN's relative efficiency against other gas service providers using multilateral total factor productivity (MTFP) estimates, partial factor productivity (PFP) estimates and an estimate of the opex cost function using econometric techniques. As a part of this

<sup>44</sup> AER, *Better Regulation – Explanatory statement expenditure forecast assessment guideline*, November 2013, pp. 65–66.

<sup>45</sup> NGR, r. 91, r. 74.

<sup>46</sup> Economic Insights, *Relative opex efficiency and forecast opex productivity growth of Jemena Gas Networks*, 10 September 2014.

analysis Economic Insights calculated JGN's forecast output change and partial factor productivity suitable for a rate of change approach.<sup>47</sup>

In order to calculate its opex rate of change, JGN commissioned reports for demand, energy and customer forecasts; real cost escalation forecasts; and opex partial factor productivity forecasts.<sup>48</sup> JGN's proposed opex rate of change is shown below in Table 7-8 and JGN's proposed price escalations are in Table 7-9.

**Table 7-8 Jemena Gas Networks' proposed opex rate of change (per cent)**

	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20
Input price change	0.47	0.92	1.19	1.25	1.15	1.32
Network growth	-4.72	-0.31	0.52	0.38	0.37	0.48
Opex partial factor productivity	-2.71	0.25	0.96	0.85	1.25	1.46
<b>Opex rate of change</b>	<b>-1.67</b>	<b>0.36</b>	<b>0.74</b>	<b>0.77</b>	<b>0.26</b>	<b>0.32</b>

Source: JGN, *Appendix 7.1, JGN opex forecast model (Updated)*, October 2014

**Table 7-9 Jemena Gas Network' proposed price escalations**

	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20
EBA	0.64	1.23	1.75	1.97	2.19	2.27
Contract	0.54	1.24	1.61	1.52	1.19	1.45
Concrete	4.50	4.50	-0.50	-2.00	-1.10	0.50
Steel	5.11	0.98	-0.20	7.96	-8.87	-5.11

Source: JGN, *Appendix 7.1, JGN opex forecast model (Updated)*, October 2014

## A.3 Assessment approach

Our assessment of the rate of change is made in the context of our assessment of the total forecast opex for JGN.

We must approve the service provider's forecast opex if we are satisfied that it complies with the opex criteria. In determining whether forecast opex complies with the opex criteria we have regard to the criteria for forecasts and estimates.<sup>49</sup> We consider the use of economic benchmarking to be a reasonable methodology to forecast the opex trend. This is our preferred approach if robust data is available.<sup>50</sup> The rate of change approach takes into account the outputs and inputs required by JGN to provide services to its customers. It also takes into account JGN's productivity in using its inputs and outputs. We consider this approach to take into account all the main drivers of opex.

<sup>47</sup> Economic Insights, *Relative opex efficiency and forecast opex productivity growth of Jemena Gas Networks*, 14 April 2014, p. 4.

<sup>48</sup> JGN, *Access arrangement information*, June 2014, p. 77

<sup>49</sup> NGR, r. 91, r. 74.

<sup>50</sup> We have previously adopted this approach for SP AusNet's 2013–17 Access Arrangement final decision where SP AusNet proposed a rate of change methodology with a firm specific productivity forecast. See AER, *SP AusNet Access arrangement final decision: Part 3 Appendices*, March 2013, p. 5

### A.3.1 Rate of change

In the *Expenditure forecast assessment guideline* for electricity we noted that once we have assessed the efficient opex in the base year we then account for any changes in efficient costs in the base year and each year of the forecast access arrangement period.<sup>51</sup>

We have also adopted this approach to assess JGN's proposed opex. Our methodology for adjusting base year opex for input price change, output growth and productivity growth is known as the rate of change.

The rate of change formula for opex is:

$$\Delta Opex = \Delta input\ price + \Delta output - \Delta productivity \quad (1)$$

Where  $\Delta$  denotes the proportional change in a variable.

Since JGN's proposed methodology is consistent with our methodology, we can compare each component of JGN's rate of change with ours on a like with like basis. The sections below outline our assessment approach for comparing each rate of change component.

#### Input price change

Under the rate of change approach opex is escalated by the change in input prices. The change in input prices accounts for key inputs that do not move in line with the CPI and form a material proportion of a service provider's costs.

The 'input price change' is made up of labour price changes and materials price changes. For labour and materials, we have assessed JGN's consultant's forecasts and compared it to our independent expert advice.

To determine the appropriate forecast change in labour prices we have assessed forecasts from BIS Shrapnel and Deloitte Access Economics (DAE). Both forecasts are based on each consultant's view of general macroeconomics trends for the utilities industry and the overall Australian economy. Our consideration of the choice of labour price forecast is discussed below in section A.4.2.

For materials, we have assessed whether JGN's proposed escalations for concrete and steel are reasonable. We have also assessed whether the materials escalation has been used consistently with Economic Insights' opex partial productivity forecasts.

#### Output change

The 'output change' captures the change in expenditure due to changes in the level of outputs delivered. The variables included in our output change measure should reflect the main drivers of a gas distribution businesses' output and should be modelled consistently between the historical and forecast period.

Under our rate of change approach, a proportional change in output results in the same proportional change in expenditure. Any subsequent adjustment for economies of scale is considered as a part of productivity.

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<sup>51</sup> AER, *Expenditure forecast assessment guidelines - Explanatory statement*, November 2013 p. 61.



We have assessed JGN's demand forecasts and methodology for selecting output growth variables. This is discussed below in section A.4.3.

## Productivity change

The 'productivity change' measure is based on the JGN's historical productivity changes in using its inputs to produce outputs. The productivity is estimated based on econometric analysis from Economic Insights that takes into account efficiency and operating environment factors of gas distribution businesses. We have also taken into account opex partial factor productivity (PFP) using Economic Insights' gas distribution service provider data set.

Productivity is a measure of how well a NSP utilises its inputs to produce outputs. An increase in productivity could be due to an increase in outputs for a given level of inputs or a decrease in inputs for a given level of outputs. A positive productivity change will decrease the rate of change. Since both outputs and inputs are taken into account, our productivity measure accounts for labour productivity and economies of scale. The effect of industry wide technical change is also included. An example of productivity change is increased efficiency due to better use of technology such as I.T.

We have assessed JGN's productivity methodology against previous economic benchmarking studies. This is discussed below in section A.4.4.

## Other considerations

The rate of change approach is used in conjunction with our assessment of base opex and step changes to determine total opex. We cannot make adjustments to base opex and step changes without also considering its effect on the opex rate of change, in particular the productivity component.

For example, a NSP that is not on the efficient opex frontier is likely to have more scope for productivity changes than a NSP that is on the efficient frontier. The inefficient NSP could potentially catch up to the efficient NSP by implementing practices the efficient NSP has already undertaken.

If we were to adjust the base opex of an inefficient NSP to the efficient frontier, it would not be reasonable to adopt a forecast productivity growth in excess of the productivity other efficient NSPs could achieve.

This relationship is also important for our step change assessment. Our forecast rate of change is influenced by historical data. Our measured productivity will include the effect of past step changes which typically increase a NSP's inputs. This will lower our measured productivity. If we include an allowance for step changes in forecast opex, there is a risk that NSPs will be compensated twice for step changes.<sup>52</sup>

## A.4 Reasons for position

### A.4.1 Overall rate of change

We consider JGN's rate of change methodology to be appropriate based on the economic benchmarking data that is available. However, we are not satisfied that the labour and materials escalations included in JGN's forecast input price changes result in an efficient forecast of overall opex.

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<sup>52</sup> Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and Tasmanian electricity TNSPs*, 6 November 2014, p. 17.

We have adjusted JGN's labour price to reflect the benchmark efficient labour price. For non-electricity, gas, water and waste services (EGWWS) labour we have adopted the CPI. This includes outsourced labour and materials price changes. These adjustments are discussed in the input price section below.

We are not satisfied with the following aspects of JGN's forecast price changes:

- the higher percentage of labour as a proportion of opex in the forecast period is inconsistent with the labour and non-labour proportions used in Economic Insights' analysis. Since labour price is increasing at a greater rate than CPI, a higher proportion of labour will result in a rate of change that is higher than using Economic Insights' weightings.
- analysis we have previously undertaken suggests that BIS Shrapnel's labour forecasts are less accurate than a forecast based on an average of BIS Shrapnel and DAE's labour forecasts for the EGWWS industry.
- JGN has not demonstrated a relationship between the change in the price of materials and the change in its total opex.

Table 7-10 shows JGN's and our overall rate of change.

**Table 7-10 AER and JGN overall rate of change (per cent)**

	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20
<b>JGN</b>						
Price change	0.47	0.92	1.19	1.25	1.15	1.32
Output change	-4.72	-0.31	0.52	0.38	0.37	0.48
Productivity change	-2.71	0.25	0.96	0.85	1.25	1.46
<b>Overall rate of change</b>	<b>-1.67</b>	<b>0.36</b>	<b>0.74</b>	<b>0.77</b>	<b>0.26</b>	<b>0.32</b>
<b>AER</b>						
Price change	0.49	0.47	0.76	0.89	0.89	0.92
Output change	-4.72	-0.31	0.52	0.38	0.37	0.48
Productivity change	-2.71	0.25	0.96	0.85	1.25	1.46
<b>Overall rate of change</b>	<b>-1.65</b>	<b>-0.10</b>	<b>0.31</b>	<b>0.42</b>	<b>-0.00</b>	<b>-0.07</b>
<b>Difference</b>	<b>0.02</b>	<b>-0.46</b>	<b>-0.43</b>	<b>-0.36</b>	<b>-0.26</b>	<b>-0.39</b>

Source: JGN, Appendix 7.1, JGN opex forecast model (Updated), October 2014; AER analysis.

## A.4.2 Input price change

Input price change is driven primarily by changes in the labour price. Specifically the difference in forecasts can be attributed to:

- the opex weighting between labour and non-labour - generally the more weight attributed to labour the higher the input price change.
- the choice of labour forecast - forecasts from different labour consultants do not necessarily match and will result in a different input price depending on which consultant's forecast is used.

Table 7-11 compares JGN's proposed forecast input price change and our forecast input price change.

**Table 7-11 Forecast input price change (per cent)**

	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20
AER	0.49	0.47	0.76	0.89	0.89	0.92
JGN	0.47	0.92	1.19	1.25	1.15	1.32

Source JGN, *Appendix 7.1, JGN opex forecast model (Updated)*, October 2014; AER analysis.

### Opex price weightings

Labour and non-labour inputs are necessary to undertake opex-related functions and activities. The forecast input price change is weighted by the proportion of opex that is labour and non-labour. We have adopted a 62 per cent weighting for labour and 38 per cent for non-labour in forecasting input price changes. The labour component is forecast based on the EGWWS industry and the non-labour component is forecast based on the consumer price index (CPI).

JGN's forecast input prices are made up of 32.8 per cent EGWWS labour, 38.3 per cent construction labour, 0.9 per cent concrete, 0.3 per cent steel and 27.7 per cent CPI.

### Consistency of input price weightings

JGN's historical opex quantity was derived by the opex price deflator developed by the Pacific Economics Group (PEG).<sup>53</sup> This opex price deflator is made up of 62 per cent EGWWS labour and five PPIs covering business, computing, secretarial, legal and accounting, and public relations services.

Table 7-12 shows the historic and forecast input weightings used by Economic Insights, JGN and us.

**Table 7-12 Opex weightings**

Historic weightings (Economic Insights)	AER forecast input price weightings	JGN forecast input price weightings
EGWWS labour 62%	EGWWS labour 62%	Construction labour 38.3%
Intermediate inputs – 19.5%	CPI 38%	EGWWS labour 32.8%

<sup>53</sup> Economic Insights, *Relative opex efficiency and forecast opex productivity growth of Jemena Gas Networks*, 14 April 2014, p. 17.

Historic weightings (Economic Insights)	AER forecast input price weightings	JGN forecast input price weightings
domestic PPI		
Data processing, web hosting and electronic information storage PPI	8.2%	CPI 27.7%
Other administrative services	6.3%	Concrete 0.9%
Legal and accounting PPI	3.0%	Steel 0.3%
Market research and statistical services PPI	1.0%	

Source: AER analysis; Economic Insights, *Relative opex efficiency and forecast opex productivity growth of Jemena Gas Networks*, 14 April 2014; *JGN opex forecast model (Updated)*, October 2014; AER analysis.

Under the rate of change approach we generally consider any input price index could be reasonable if applied to both the historical and forecast period and reflects the NSP's opex inputs. Further, robust forecasts and historical data must be available. In principle we consider modelling techniques which use the same input weightings, for both historical and forecast data, to be more robust than adopting inconsistent weightings.

We note JGN's forecast input price weightings are inconsistent with the historical opex price deflator. JGN has included construction labour and materials escalation to forecast input prices. This approach could be reasonable if the historical calculations also included construction labour and materials price escalation.

The difference between the historical and forecast price deflators used by JGN is likely to affect the productivity measure. For example, if the historical price change for materials, such as concrete, is higher than the five PPIs used by Economic Insights, then the productivity forecast which is based on the five PPIs will be underestimated. This is because deflating opex by a higher price change means a lower opex amount which results in lower inputs and higher productivity.

We note the average annual historical WPI for construction labour from 2008 to 2013 is 3.7 per cent which is higher than the CPI of 2.33 per cent for the same period. This means that if construction labour was used to calculate the opex cost function then it would likely result in a higher productivity forecast which would offset the higher price.

### **Forecast of producer price indices and CPI**

Our weightings for the forecast input price are broadly consistent with Economic Insights' benchmarking analysis for electricity service providers which applied weights of 62 per cent EGWWS wage price index (WPI) for labour and 38 per cent for five producer price indices (PPIs) for non-labour. The five PPIs cover business, computing, secretarial, legal and accounting, and public relations services.<sup>54</sup>

For the purposes of forecasting input price changes we have applied the forecast CPI rather than forecasts for each PPI. We consider forecasts of CPI to be more robust than forecasts of each PPI.

<sup>54</sup> Economic Insights, *Measurement of Inputs for Economic Benchmarking of Electricity Network Service Providers*, 22 April 2013, p. 4.

To forecast CPI we adopt a forecast of inflation outlined in the Reserve Bank of Australia's (RBA's) Statement of Monetary Policy and for the years beyond that we apply the mid-point of the RBA's target band. Forecasts for CPI are also more readily available than forecasts of each PPI. For this reason we have used forecast CPI to forecast the non-labour component of input price changes.

Economic Insights noted that while the use of these PPIs is likely to be more accurate for historic analysis, it is unlikely to be practical for applications requiring forecasts of the opex price index such as the rate of change. This is because it is very difficult to obtain price forecasts at a finely disaggregated level other than by simple extrapolation of past trends.<sup>55</sup> We recognise that the use of PPIs for historical purposes and CPI for forecasts may be inconsistent. However, sensitivity analysis from Economic Insights showed the effect of using CPI compared to the five PPIs indicated no material difference in the economic benchmarking results. This is because the change in PPIs follows a similar trend to the change in CPI.

## Materials

For gas distribution, we typically escalate materials by CPI. In applying a specific material escalation, different from CPI, we would need to have robust forecasts of the relevant inputs and be satisfied that there is an empirical relationship between commodity prices and final product prices paid by JGN.<sup>56</sup> JGN did not provide evidence to demonstrate this relationship. We also note that since JGN's concrete and steel escalations make up 0.88 per cent and 0.30 per cent of total opex, deviations in the price of these materials from the CPI would not have a material impact on the opex forecast.

Further, JGN has not demonstrated a relationship between the change in the price of materials and the change in its total opex.

The Energy Markets Reform Forum (EMRF) noted that materials prices are difficult to predict and can be volatile over a short period of time. The EMRF would also expect the gas networks to undertake prudent hedging arrangement for currency and commodity prices given the volatility of the various internationally linked prices and the relative certainty of the networks demand for each of the products.<sup>57</sup>

We agree that due to the volatility of currency and commodity prices we would expect a prudent service provider would hedge its materials costs to reduce the potential for volatile input costs.

## Labour price change

Our choice of the labour price measure seeks to select the efficient labour price for an efficient service provider on the opex frontier. To determine the efficient labour price we require a forecast of the benchmark labour price. We consider forecasts of the EGWWS industry, produced by expert forecasters, to be an appropriate benchmark for JGN's labour price.

### Choice of labour forecast

To forecast labour we have adopted the average of Deloitte Access Economics (DAE) and BIS Shrapnel's WPI forecasts for the EGWWS sector.

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<sup>55</sup> Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 29 October 2014, p. 14.

<sup>56</sup> AER, *Access arrangement draft decision SPI Networks (Gas) Pty Ltd*, p. 81.

<sup>57</sup> EMRF, *Australian Energy Regulatory NSW Gas Distribution Revenue Reset Jemena Application - A response by the Energy Markets Reform Forum*, August 2014, p. 42.

We consider an averaging approach that takes into account the consultants' forecasting history, if available, to be the best method for selecting the labour price.

This is based on our previous analysis<sup>58</sup> which was corroborated by Professor Borland's analysis.<sup>59</sup> We have previously adopted the averaging approach because Deloitte Access Economics typically forecast lower than actual WPI and BIS Shrapnel typically forecast higher than actual WPI for the Australian EGWWS sector.

DAE's analysis also shows that DAE's forecasts were too pessimistic. In contrast BIS Shrapnel's were too optimistic and by a greater margin.<sup>60</sup>

We previously adopted the average of the forecasts from BIS Shrapnel and DAE to obtain the best labour price measure under a rate of change approach for SP AusNet's gas distribution network.<sup>61</sup>

We have compared both DAE and BIS Shrapnel's forecasts for the NSW EGWWS industry. These forecasts are shown in Table 7-13.

**Table 7-13 Comparison of consultant labour forecasts for NSW EGWWS industry (per cent)**

	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	Average
<b>Nominal</b>								
Deloitte	3.20	3.30	2.90	3.40	3.50	3.30	3.30	3.27
BIS Shrapnel	3.60	3.40	3.70	4.20	4.50	4.70	4.80	4.13
<b>Real</b>								
Deloitte	0.60	0.60	0.40	0.50	1.00	0.90	1.00	0.71
BIS Shrapnel	0.80	0.60	1.20	1.70	2.00	2.20	2.30	1.54
<b>CPI</b>								
Deloitte	2.70	2.50	2.50	2.90	2.50	2.40	2.40	2.56
BIS Shrapnel	2.80	2.80	2.50	2.50	2.50	2.50	2.50	2.59

Source: Deloitte Access Economics, *Forecast growth in labour costs in NSW, Tasmania and the ACT*, 24 July 2014, p. 8; BIS Shrapnel, *Real Labour and Material Cost Escalation Forecasts to 2019/20*, 4 June 2014, p. ii.

As can be seen in Table 7-13 the historical trend of BIS Shrapnel forecasting lower than DAE has continued for the 2013–14 to 2018–19 forecast period. We note the Australia-wide EGWWS for 2013–14 was 3.04 per cent in nominal terms<sup>62</sup> and CPI was 3.02 per cent for the same period.<sup>63</sup> This results in a 0.02 per cent real increase in national EGWWS labour. Both consultants' forecasts for 2013–14 EGWWS labour are higher than the ABS' actual figures.

<sup>58</sup> AER, *Access arrangement final decision SPI Networks (Gas) Pty Ltd 2013–17 – Part 3: appendices*, March 2013, p. 7.

<sup>59</sup> AER, *Access arrangement final decision SPI Networks (Gas) Pty Ltd 2013–17 – Part 3: appendices*, March 2013, p. 7.

<sup>60</sup> AER, *Powerlink Final decision*, April 2012, p. 54.

<sup>61</sup> AER, *Access arrangement final decision SPI Networks (Gas) Pty Ltd 2013–17 – Part 3: appendices*, March 2013, p. 7.

<sup>62</sup> ABS, 6345.0 - Wage Price Index, Australia, Table 9b. Ordinary Hourly Rates of Pay Excluding Bonuses: Sector by Industry, Original (Quarterly Index Numbers), 12 August 2014.

<sup>63</sup> ABS, 6401.0 - Consumer Price Index, Australia, TABLES 3 and 4. CPI: Groups, Weighted Average of Eight Capital Cities, Index Numbers and Percentage Changes, 22 July 2014.

The Major Energy Users (MEU) noted forecasts by DAE and BIS Shrapnel typically overestimate the wage price index and that the AER does not assess the actual accuracy of the forecasts over time.<sup>64</sup> Origin in its assessment of BIS Shrapnel's forecasts for the NSW EGWWS industry noted that:

Overall, Origin believes that BIS Shrapnel has overestimated internal and external labour pressures in the utilities sector, meaning wages growth will be more muted following the fall in national construction activity. A combination of interstate and local labour supply will help to ease wage pressures in the utilities sector at a time when investment in energy networks in NSW has peaked. JGN can therefore expect that cost escalations with respect to wages will be much more muted than BIS Shrapnel has forecast.<sup>65</sup>

We consider the consultants should take the recent ABS data into account when providing updated forecasts. We cannot assess the detailed assumptions and modelling techniques used in consultants' models. However we consider the forecasts should reflect current expectations of the labour market for the forecast period. The consultants have identified the assumptions that are driving their forecasts. However, we can only observe the overall labour forecast provided by the consultant. The effect of each individual assumption on the consultant's forecast is proprietary information and is not available to us.

The EMRF noted that AER has consistently used DAE's forecasts in preference to BIS Shrapnel's and should continue to do so for the sake of consistency. If, however, the AER chooses to accept JGN's forecasts, then the AER should build in greater productivity improvements into the forecast so that overall labour costs do not increase above CPI.<sup>66</sup> We have assessed the forecasting performance of both DAE and BIS Shrapnel. As noted above, we have found that DAE typically forecasts below and BIS Shrapnel forecasts above the wage price index and we have addressed this issue by averaging these consultants' forecasts. We consider this, based on each consultants' forecasting history, to be the best forecast of labour price. The interaction between labour price and productivity is an important consideration in our overall rate of change approach and is discussed above in our opex weightings section. We note our labour price forecasts are likely to change prior to the final decision to reflect the most up to date data.

## Non-EGWWS labour

JGN proposed the use of construction labour for its external labour costs. We do not consider construction labour to be relevant to opex. The Australian Bureau of Statistics (ABS) previously advised:

... regardless of the type of job, if the job was selected from a business classified to the electricity, gas, water and waste services industry, the jobs pay movements contributes to this industry.<sup>67</sup>

The ABS labour price statistics for the EGWWS industry reflects both specialised gas distribution network related labour and general labour from EGWWS businesses.

We consider operating and maintenance work to be more relevant to the EGWWS industry than the construction industry work. Further, any outsourced work covering business, computing, secretarial, legal and accounting, and public relations services should be attributed to the five PPI's or CPI rather than to construction labour.

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<sup>64</sup> Major Energy Users, Tasmanian Electricity Transmission Revenue Reset A response by the Major Energy Users Inc, August 2014, p. 28.

<sup>65</sup> Origin, Submission to Jemena's Access Arrangement Proposal, 25 August 2014, p. 8.

<sup>66</sup> EMRF, Australian Energy Regulatory NSW Gas Distribution Revenue Reset Jemena Application - A response by the Energy Markets Reform Forum, August 2014, p. 41.

<sup>67</sup> ABS, *Email from Kathryn Parlor to Fleur Gibbons*, 8 July 2010.



### A.4.3 Output change

We consider the output change methodology prepared by Economic Insights on behalf of JGN to be appropriate and we have adopted the same methodology for our forecast rate of change.

The output weights determined by Economic Insights are:

- throughput (55 per cent)
- customers (45 per cent)<sup>68</sup>

These output weights are based on already established literature. Based on previous studies we consider these weightings to also be appropriate for JGN's output change.<sup>69</sup>

In response to our information request JGN and Economic Insights updated its modelling which resulted in a change to its forecast outputs. This resulted in a lower output growth than initially proposed by JGN. Our forecast output change reflects the updated forecast outputs.<sup>70</sup>

We note the level of throughput and customer numbers should reflect our assessment of demand in attachment 6. Since the output change and productivity change are related through economies of scale we have not made an isolated adjustment to JGN's output change for the draft decision. However, similar to our position on the labour price forecast we consider JGN's revised proposal should reflect the most recent data available which will affect both JGN's output change and economies of scale.

### A.4.4 Opex partial factor productivity

We consider that JGN's forecast average productivity of 0.95 per cent per year for 2014–15 to 2019–20 is reasonable.

While we have concerns with JGN's cost function used to forecast productivity, due to data and modelling issues, we note that JGN's forecast of productivity sits within the range of our alternative productivity forecasts.

JGN's methodology for forecasting productivity is consistent with our preferred approach set out in the expenditure forecast assessment guidelines for electricity.<sup>71</sup> The productivity forecast is computed according to the opex partial productivity growth formula using parameter estimates from the Economic Insights' opex cost function modelling and JGN's forecasts for the relevant cost drivers.<sup>72</sup> The productivity forecast is made up of the following three components:

1. technology
2. returns to scale
3. operating environment factors

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<sup>68</sup> JGN, *Appendix 7.1, JGN opex forecast model (Updated)*, October 2014.

<sup>69</sup> Economic Insights, *Relative opex efficiency and forecast opex productivity growth of Jemena Gas Networks*, 3 October 2014, p. 17.

<sup>70</sup> JGN, *Response to AER information request JGN036*, 7 October 2014.

<sup>71</sup> AER, *Expenditure forecast assessment guideline – Explanatory statement*, November 2013, pp. 65–66.

<sup>72</sup> Economic Insights, *Relative opex efficiency and forecast opex productivity growth of Jemena Gas Networks*, 2 October 2014, p. 37.



In response to our information request JGN and Economic Insights updated its modelling which resulted in a change to its opex productivity modelling. This resulted in a lower productivity change than the 1.03 per cent initially proposed by JGN. Our forecast rate of change in Table 7-10 reflects the updated forecast productivity produced by Economic Insights.<sup>73</sup>

Economic Insights estimated the average annual technological change to be 0.76 per cent and 0.83 per cent based on its feasible generalised least squares (FGLS) and stochastic frontier analysis (SFA) models. Depending on the model used, technology represents the frontier shift or shift in average productivity.<sup>74</sup>

However, as shown in Table 7-10 JGN's forecast productivity changes each year. This is driven by changes to economies of scale, which is based on output change, and operating environment factors. Economic Insights included the following operating environment factors in its analysis:

- customer density
- capital (constant price RAB)
- the proportion of mains that are not cast iron or unprotected steel, and
- a measure of service area dispersion.<sup>75</sup>

We note that there are some issues that may affect the robustness of Economic Insights' opex cost function analysis. For instance

- The data set uses regulatory information that is available in the public domain for all businesses other than JGN. Data extracted from a mix of sources, particularly financial information such as opex, may not necessarily be reported consistently over time and across gas distribution businesses.
- Although two New Zealand gas distribution businesses were added to the data to improve the robustness of the data set, there was relatively limited cross-sectional variation included in the data set.
- The forecast and regulatory proposal data are used for gas distribution businesses other than JGN where actual data is not available. This may be different to what was realised which could affect the benchmarking results.
- We consider there could be further sensitivity analysis undertaken to demonstrate the robustness of the model specification adopted by JGN.

We also note Economic Insights has also applied an index-number-based method to estimate total factor productivity and opex partial factor productivity performance for some of the Australian gas distribution businesses. Index numbers are more robust to data point issues than opex cost functions.<sup>76</sup> Also the data used are from the same source; that is, survey data collected by Economic

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<sup>73</sup> JGN, *Response to AER information request JGN027*, 10 September 2014.

<sup>74</sup> Economic Insights, *Relative opex efficiency and forecast opex productivity growth of Jemena Gas Networks*, 14 April 2014, p. 46.

<sup>75</sup> Economic Insights, *Relative opex efficiency and forecast opex productivity growth of Jemena Gas Networks*, 10 September 2014, p. 46.

<sup>76</sup> Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and Tasmanian electricity TNSPs*, October 2014, p. iii.

Insights. We applied the use of opex PFP for our draft TransGrid determination where the data set was not sufficiently robust enough to adopt an opex cost function.

Table 7-14 shows the opex PFP and MTFP for JGN and the gas industry using energy throughput, customer numbers and system capacity.

**Table 7-14 JGN and gas industry average opex PFP and MTFP (per cent)**

	Opex partial factor productivity			Multilateral total factor productivity		
	1999–2013	1999–2006	2006–2013	1999–2013	1999–2006	2006–2013
JGN	4.38	8.05	0.83	0.96	2.28	–0.33
Industry average	4.36	5.99	2.12	1.10	1.83	0.11

Source: AER analysis.

We note that there are a range of possible productivity forecasts that can be adopted from MTFP, opex PFP and opex cost function analysis. JGN and the gas industry in general experienced higher opex PFP from 1999–2006 than 2006–13.

JGN proposed average annual productivity of 0.95 per cent is similar to its opex PFP of 0.83 per cent from 2006–13 and lower than the industry average for the same period. This indicates that JGN's proposed productivity is at the lower end of the range of potential productivity forecasts using opex PFP method. The index number method does not provide a decomposition of opex productivity change into sources such as efficiency change, technical change, scale efficiency change, or the extent of capital-labour substitution. Without further evidence on the differing scope of potential opex productivity that the gas distribution businesses may face, we are satisfied that an average productivity forecast of 0.95 per cent is reasonable.

The EMRF does not accept a productivity improvement of 1.03 per cent to be sufficient given capex increases and new IT systems should have allowed greater savings in opex than is apparent in the JGN forecast. The EMRF also noted the Australian gas industry as a whole was more than 27 per cent less efficient than its overseas counterparts based on an IPART study.<sup>77</sup>

We note the IPART study was conducted in 1999<sup>78</sup> and since then the industry average opex PFP was 4.36 per cent. This indicates that since 1999 the Australian gas distribution industry as a whole achieved substantial productivity improvements and the results of the 1999 IPART study may not necessarily be applicable to productivity change for the 2014–19 period.

<sup>77</sup> EMRF, *Australian Energy Regulatory NSW Gas Distribution Revenue Reset Jemena Application - A response by the Energy Markets Reform Forum*, August 2014, p. 42.

<sup>78</sup> EMRF, *NSW gas distribution revenue reset Jemena application*, 9 November 2009, p. 39.