



**FINAL DECISION**  
**Australian Gas Networks**  
**Access Arrangement**  
**2016 to 2021**

**Attachment 7 – Operating**  
**expenditure**

May 2016

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## Note

This attachment forms part of the AER's final decision on the access arrangement for Australian Gas Networks South Australian distribution network for 2016–21. It should be read with all other parts of the final decision.

The final 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 carryover mechanism

Attachment 10 - Reference tariff setting

Attachment 11 - Reference tariff variation mechanism

Attachment 12 - Non-tariff components

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Attachment 14 - Other incentive schemes

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## Shortened forms

Shortened form	Extended form
AA	Access Arrangement
AAI	Access Arrangement Information
AER	Australian Energy Regulator
AGN	Australian Gas Networks
ATO	Australian Tax Office
capex	capital expenditure
CAPM	capital asset pricing model
CCP	Consumer Challenge Panel
CESS	Capital Expenditure Sharing Scheme
CPI	consumer price index
CSIS	Customer Service Incentive Scheme
DRP	debt risk premium
EBSS	Efficiency Benefit Sharing Scheme
ECM	Efficiency Carryover Mechanism
ERP	equity risk premium
Expenditure Guideline	Expenditure Forecast Assessment Guideline
gamma	value of imputation credits
GSL	Guaranteed Service Level
MRP	market risk premium
NECF	National Energy Customer Framework
NERL	National Energy Retail Law
NERR	National Energy Retail Rules
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
NIS	Network Incentive Scheme
NPV	net present value
opex	operating expenditure
PFP	partial factor productivity
PPI	partial performance indicators
PTRM	post-tax revenue model

Shortened form	Extended form
RBA	Reserve Bank of Australia
RFM	roll forward model
RIN	regulatory information notice
RoLR	retailer of last resort
RPP	revenue and pricing principles
SLCAPM	Sharpe-Lintner capital asset pricing model
STPIS	Service Target Performance Incentive Scheme
TAB	tax asset base
UAFG	unaccounted for gas
WACC	weighted average cost of capital
WPI	Wage Price Index

## 7 Operating expenditure

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

This attachment provides an overview of AGN's opex proposal and our assessment of total opex.

### 7.1 Final decision

We are satisfied that the forecast of total opex AGN proposed complies with the opex criteria and the criteria for forecasts and estimates.<sup>1</sup> We therefore accept the forecast of opex AGN included in its revised proposal. Our final opex decision for the 2016–21 access arrangement period is shown in Table 7.1.

**Table 7.1 Final decision on total opex (\$million, 2015–16)**

	2016-17	2017-18	2018-19	2019-20	2020-21	Total
AGN's initial proposal	68.39	70.58	72.44	72.64	73.39	357.43
AER draft decision <sup>2</sup>	68.60	69.53	69.95	69.73	69.60	347.40
AGN's revised proposal	70.72	72.10	73.51	73.56	73.73	363.62
AER final decision	70.72	72.10	73.51	73.56	73.73	363.62

Source: AER analysis.

Note: Excludes debt raising costs.<sup>3</sup> Numbers may not add up due to rounding.

Figure 7.1 shows our final decision compared to AGN's proposal, its past allowances and past actual expenditure.

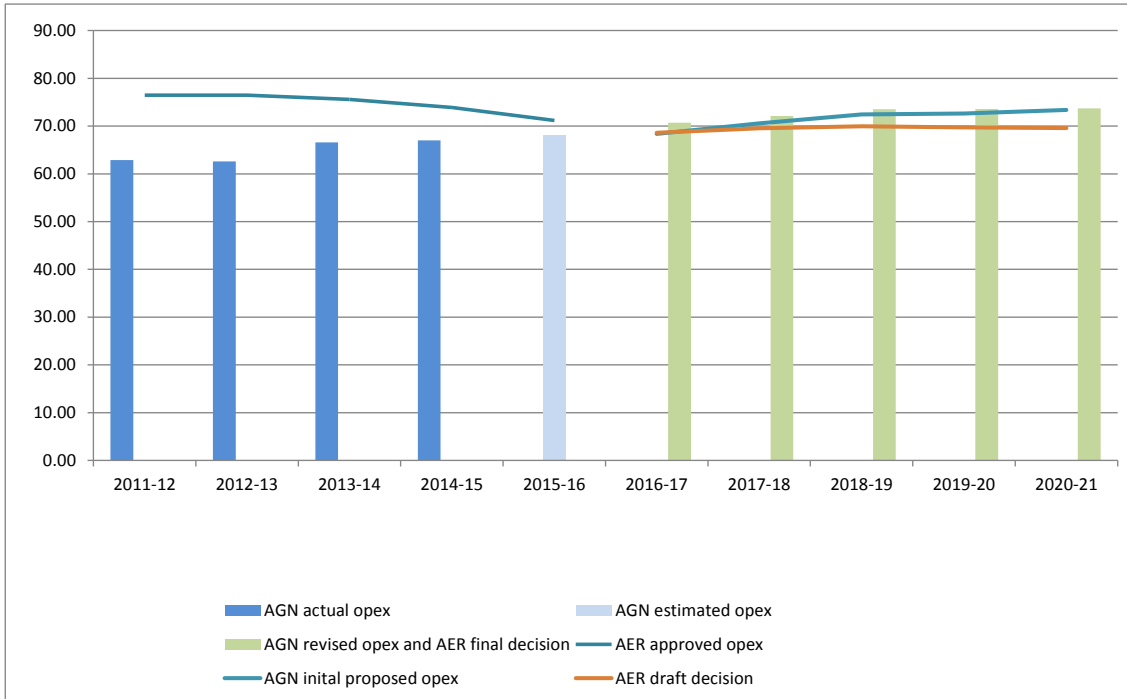
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<sup>1</sup> NGR, rr. 74, 91.

<sup>2</sup> After the release of our draft decision we corrected a modelling error which led to an increase in approved opex from \$342.35 million to \$347.40 million. AGN was advised of this error before the submission of its revised proposal.

<sup>3</sup> Debt raising costs are discussed in this final decision in Attachment 3 (Rate of Return).

**Figure 7.1 Final decision compared to AGN's past and proposed opex (\$million, 2015–16)**



Source: AER analysis

## 7.2 AGN's revised proposal

AGN's revised opex forecast was \$364 million (\$2015–16) over the access arrangement period. This is an increase of 2 per cent on its initial access arrangement proposal.<sup>4</sup>

In its revised proposal AGN adopted the same forecasting approach as in its initial proposal with some revisions to the inputs:<sup>5</sup>

- 2014–15 opex updated to reflect actual opex
- Unaccounted for gas (UAFG) - AGN updated UAFG quantities to reflect its revised mains replacement program, and UAFG prices to reflect more recent price forecasts.
- Rate of change - AGN accepted our draft decision on input cost escalation and output growth but proposed a productivity adjustment of zero.
- Step changes - AGN re-proposed one step change and conditionally re-proposed another step change.

<sup>4</sup> Australian Gas Networks, *Revised Access Information for Australian Gas Networks' South Australian Natural Gas Distribution Network, Attachment 7.8: Response Draft Decision Operating Expenditure*, January 2016, p. 19.

<sup>5</sup> Australian Gas Networks, *Revised Access Information for Australian Gas Networks' South Australian Natural Gas Distribution Network, Attachment 7.8: Response Draft Decision Operating Expenditure*, January 2016, p. 3.



- Re-categorisation of projects - consistent with our draft decision, AGN accepted the re-categorisation of three projects to opex and their incorporation into the base year opex.<sup>6</sup>

We assessed AGN's revised opex forecast against our alternative estimate of opex in section 7.4. The approach we used to assess AGN's opex forecast is outlined in section 7.3.

### 7.3 AER's 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) outlined in the NGR.<sup>7</sup>

#### Rule 91. Criteria governing operating expenditure

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

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

#### Rule 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:
  - (a) must be arrived at on a reasonable basis; and
  - (b) must represent the best forecast or estimate possible in the circumstances.

To assist us in forming a view on whether a service provider's proposed opex complies with the opex criteria we compare the service provider's total forecast opex with our alternative estimate of total opex.

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.

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<sup>6</sup> AGN originally only accepted the reclassification of two projects, but later revised its position on the third project. See section 7.4.4.3 for more detail.

<sup>7</sup> Also see NGR, r. 40(2).

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. If we are not satisfied that the proposed opex complies with the opex criteria we use our alternative opex estimate as a substitute. Conversely, if the service provider's forecast is consistent with our estimate, this may suggest that the service provider's forecast is consistent with the opex criteria and we may accept the forecast.

Whether or not we accept a service provider's forecast, we will provide the reasons for our decision.

### 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.<sup>8</sup>
2. We assess whether opex in that base year complies with the opex criteria. If necessary, we make an adjustment to the base year expenditure to ensure that it complies with 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 total opex to account for any other forecast cost changes over the forthcoming access arrangement 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 other 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.<sup>9</sup>

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<sup>8</sup> AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013 and AER, *Explanatory Statement Expenditure Forecast Guideline*, November 2013.

<sup>9</sup> AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013 and AER, *Explanatory Statement Expenditure Forecast Guideline*, November 2013.

We set out more detail about each of the steps we follow in our draft decision.<sup>10</sup>

### 7.3.2 Interrelationships

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

- the operation of the efficiency carryover mechanism in the 2011–16 period, which provided AGN an incentive to reduce opex throughout that period (section 7.4.2 and Attachment 9)
- the impact of forecast demand on output growth in the rate of change (section 7.4.3 and Attachment 13)
- the interrelationship between capex and opex in considering proposed step changes (section 7.4.4)
- the approach to the assessing rate of return, to ensure there is consistency between our determination of debt raising costs and the rate of return building block (Attachment 3)
- concerns of stakeholders identified in the course of AGN's consultation with consumers and in submissions to the AER.

## 7.4 Reasons for final decision

We are satisfied AGN's proposed forecast of total opex complies with the opex criteria and the criteria for forecasts and estimates.<sup>11</sup> We reached this conclusion after undertaking analysis using our opex forecasting approach. When we compare AGN's revised total forecast opex with our estimate of the efficient opex a prudent operator would require to achieve the opex objectives, AGN's revised proposal is not materially different. We therefore accept the forecast of opex AGN included in its revised proposal. We summarise AGN's revised forecast opex and our alternative estimate in Table 7.2.

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<sup>10</sup> AER, *Draft Decision: Australian Gas Networks (SA) Access Arrangement 2016-21, Attachment 7*, November 2015, pp. 7-10 to 7-13.

<sup>11</sup> NGR, rr. 74, 91.

**Table 7.2 AGN revised proposal and AER alternative forecast of total opex (\$million, 2015–16)**

	2016-17	2017-18	2018-19	2019-20	2020-21	Total
AGN revised total forecast opex	70.72	72.10	73.51	73.56	73.73	363.62
AER alternative estimate	73.25	72.56	72.36	72.24	72.13	362.55
% Difference	3.46	0.64	-1.58	-1.83	-2.22	-0.30

Source: AER analysis.

Our reasons for why we are satisfied that AGN's revised total forecast opex reasonably reflects the opex criteria are set out in more detail below. We discuss each element of AGN's revised forecast opex. We outline the key elements of our alternative opex forecast and areas of difference between our estimate of opex and AGN's estimate below.

### 7.4.1 Forecasting method

AGN's revised opex forecast retains the base-step-trend approach used in its initial proposal, and that is consistent with our method. We are satisfied AGN's forecasting method is not the key driver of the difference between our and AGN's forecast opex. Rather, different inputs and assumptions used in the forecasting method explain the difference.

### 7.4.2 Base year opex

Determining efficient, recurrent expenditure in the base year is at the core of our single year revealed cost approach.

We are satisfied that AGN's revised 2014–15 base year opex of \$58 million (\$2015-16) is a reasonable estimate for the purpose of forecasting opex for the 2016–21 period.<sup>12</sup>

#### *Is base opex efficient?*

Relevant to our assessment of the base year opex is that AGN was subject to an opex efficiency incentive mechanism in the 2010–15 period. Typically, where a service provider is subject to an incentive mechanism, we are satisfied that there is a continuous incentive for a service provider to make efficiency gains and it does not have an incentive to increase its opex in the proposed base year. AGN achieved improvements in its opex over the 2010–15 period, suggesting it was responding to the

<sup>12</sup> Australian Gas Networks, *Australian Gas Networks SA Access Arrangement Information*, July 2015, p. 192.

cost minimisation incentives in the framework and that its revealed costs are a reasonable basis for determining its forecast costs.<sup>13</sup>

We have not been presented with evidence to suggest that AGN's revealed costs in its proposed base year are materially inefficient.

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

The Energy Consumer's Coalition of South Australia's (ECCSA) submission questions whether the AER should use another year for base opex in the current period.<sup>14</sup> We do not agree that another year should be used as the base year.

In making our assessment of AGN's efficient opex, we have relied primarily on analysis of AGN's historical trends and the gas service provider productivity analysis which AGN submitted as part of its regulatory proposal.<sup>15</sup>

AGN's revised proposal maintains 2014–15 as the base year, which we accept. AGN provide updated data for total actual opex in 2014–15. This is \$58 million (\$2015–16) excluding debt raising costs.

The reasons we considered that AGN's base year is a reasonable base year for forecasting opex in our draft decision remain:<sup>16</sup>

- As opex is generally recurrent, actual costs incurred in 2014–15 are likely to be a good indicator for the efficient costs to be incurred in the 2016–21 period.
- 2014–15 is the second last year of the current access arrangement period. The second last year is usually the most recent data 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.
- AGN's opex is relatively stable across the 2011–16 period. For instance, opex in 2013–14 is not significantly different from the equivalent opex in 2014–15.
- AGN's opex was subject to an efficiency carryover mechanism in the 2011–16 period, which reduces any incentive for AGN to increase opex in its proposed base year.
- AGN adjusted its base year to remove non-recurrent costs relating to a transmission pipeline failure in Port Pirie and Whyalla.

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<sup>13</sup> Attachment 9 contains information on the efficiency carryover mechanism applied to AGN in the 2010–15 period.

<sup>14</sup> Energy Consumer's Coalition of South Australia, *Response to the AER Draft Decision on AGN's AA 2016 Revenue Reset*, February 2016, p. 24.

<sup>15</sup> Economic Insights, *Benchmarking Australian Gas Networks' South Australian Business Operating and Capital Costs using Partial Indicators*, report prepared for Australian Gas Networks Limited, 21 May 2015, p. iv. (Attachment 4.2 to AGN's Access Arrangement Information July 2015). AER, *Draft Decision: Australian Gas Networks (SA) Access Arrangement 2016-21, Attachment 7*, November 2015, p. 7-15.

<sup>16</sup> See AER, *Draft Decision: Australian Gas Networks (SA) Access Arrangement 2016-21, Attachment 7*, November 2015, p. 7-16.

- We did not find any further evidence of non-recurrent expenditure in AGN's proposed adjusted base year, once the non-recurrent expenditure that AGN identified had been removed.

### *Base year adjustments*

AGN's updated forecast for base year opex is \$11.4 million more than the forecast base year opex of \$47 million (\$2015–16) set out in its initial proposal. This difference is largely attributed to AGN accepting the base year adjustments we set out in our draft decision. Specifically, AGN has accepted our draft decision with respect to category-specific forecasts for Network Management Fee (NMF), ancillary reference services and insurance costs. We considered these costs are broadly recurrent and lead to a total forecast of opex that is recurrent such that they should be included in base year opex, rather than forecast separately.

AGN also accepted our adjustment to base year opex to include expenditure on two projects re-categorised from capex to opex.<sup>17</sup> Following our review of AGN's revised proposal, we sought clarification from AGN on its categorisation of a third project (Valve Corrosion Protection SA09) as capex.<sup>18</sup> AGN reviewed its categorisation of this project and agreed to accept the AER's draft decision to categorise this project as opex.<sup>19</sup> As a result we further increased our alternative estimate of base year opex by \$0.2 million (\$2015–16).

### **7.4.3 Rate of change**

Once we determine the efficient base level of opex, we apply a forecast annual rate of change to account for efficient changes in opex over time. In the *Expenditure Forecast Assessment Guideline* we developed a methodology for adjusting base year opex known as the rate of change.<sup>20</sup> The rate of change is the 'trend' component of the Base–Step–Trend forecasting method and is forecast as:

$$\Delta Opex = \Delta input\ price + \Delta output - \Delta productivity^{21}$$

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. These three opex drivers should explain all changes in efficient opex. The output and

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<sup>17</sup> See AER, *Draft Decision: Australian Gas Networks (SA) Access Arrangement 2016-21, Attachment 7*, November 2015, pp. 7-30 to 7-31.

<sup>18</sup> This issue is discussed in more detail in section 7.4.4.3 of this attachment.

<sup>19</sup> Australian Gas Networks, *Response to Information Request 034*, 4 February 2016.

<sup>20</sup> AER, *Expenditure forecast assessment guidelines - Explanatory statement*, November 2013, p. 61.

<sup>21</sup> The formula used by the AER to derive total rate of change takes into account the cumulative nature of the rate of change factors, rather than the simplified formula shown here. That is:

$$Rate\ of\ change = (1 + price\ growth) \times (1 + output\ growth) \times (1 - productivity\ growth) - 1.$$

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.

### 7.4.3.1 Overall rate of change

The difference between AGN's proposed overall rate of change and our forecast rate of change is due to our use of updated input and output growth data. Table 7.3 compares our final position on each rate of change component and the overall rate of change within AGN's revised proposal.

**Table 7.3 AGN revised proposal and AER final decision on overall rate of change (per cent)**

	2016–17	2017–18	2018–19	2019–20	2020–21
<b>AGN revised proposal</b>					
Input price change	0.47	0.63	0.77	0.86	0.92
Output change	-0.01	0.00	0.00	0.00	0.00
Productivity change	0.00	0.00	0.00	0.00	0.00
<b>Overall rate of change</b>	<b>0.45</b>	<b>0.62</b>	<b>0.76</b>	<b>0.85</b>	<b>0.92</b>
<b>AER final decision</b>					
Input price change	0.31	0.45	0.56	0.75	0.91
Output change	0.27	-1.06	-0.33	-0.22	-0.13
Productivity change	0.00	0.00	0.00	0.00	0.00
<b>Overall rate of change</b>	<b>0.57</b>	<b>-0.61</b>	<b>0.23</b>	<b>0.53</b>	<b>0.78</b>

Source: Australian Gas Networks, *Revised Access Information for Australian Gas Networks' South Australian Natural Gas Distribution Network 2016-21, Attachment 7.7A: Operating Expenditure Model*, January 2016; AER analysis. Numbers may not add up due to rounding.

In our final rate of change:

- input price change reflects the latest labour price growth forecasts. AGN accepted this approach in its revised proposal. The derivation of the percentage change in input price has also been corrected in the model.
- output change has been updated, reflecting revised forecast demand and customer numbers. AGN accepted this approach in its revised proposal.
- we have applied a zero rate of productivity change, based on our own analysis and additional information AGN provided in its revised proposal.

The following sections outline our assessment for each rate of change component.

### 7.4.3.2 Input price change

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

AGN accepted our draft decision to derive input price changes using real labour cost forecasts from BIS Shrapnel (BIS) and Deloitte Access Economics (DAE), and setting the price change for materials to zero.<sup>22</sup>

Business SA stated the AER had not sufficiently justified its allowance of above CPI labour cost increases for AGN in the 2016–21 period, which it considered was out of step with the commercial realities of the South Australian economy.<sup>23</sup> Business SA reiterated its concerns about the methodology used by external consultants, such as BIS Shrapnel, to justify above-CPI labour cost increases for AGN.<sup>24</sup>

Our labour cost forecasts are an average of the forecasts derived by BIS and DAE. We consider the averaging approach provides a reasonable forecast of labour cost escalation. Both the DAE and BIS Shrapnel forecasts are based on each consultant's view of general macroeconomics trends for the utilities industry and the overall Australian economy. Both also use the Australian Bureau of Statistics (ABS) Electricity, Gas, Water, Waste Service (EGWWS) sector to develop their wages forecasts which we consider to be the most appropriate benchmark to arrive at the best forecast.

Further, we consider an averaging approach that takes into account the consultants' forecasting history, if available, to be a better method for forecasting changes in labour prices. We have adopted the averaging approach in the past because DAE typically forecast lower than actual Wage Price Index (WPI) and BIS Shrapnel typically forecast higher than actual WPI for the Australian EGWWS sector.<sup>25</sup>

Therefore, we have not altered our method for forecasting input price change in our final decision. We have used the latest labour price growth forecasts in our final decision.<sup>26</sup> We also identified and corrected an error in the opex model in the formula for calculating the input cost escalator. These changes result in slight differences in input price change from our draft decision and AGN's revised proposal. Table 7.4 contains our final decision on input price change.

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<sup>22</sup> Australian Gas Networks, *Revised Access Information for Australian Gas Networks' South Australian Natural Gas Distribution Network, Attachment 7.8: Response Draft Decision Operating Expenditure*, January 2016, pp. 8–9.

<sup>23</sup> Business SA, *Submission on AER draft decision and AGN revised proposal*, 29 January 2016, p. 1.

<sup>24</sup> Business SA, *Submission on AER draft decision and AGN revised proposal*, 29 January 2016, p. 3.

<sup>25</sup> AER, *Access arrangement final decision SPI Networks (Gas) Pty Ltd 2013–17 – Part 3: appendices*, March 2013, p. 7.

<sup>26</sup> This included using February 2016 DAE forecasts for South Australian labour price growth. We also obtained from AGN updated BIS Shrapnel data - see Australian Gas Networks, *Response to Information Request 043*, 26 February 2016.



**Table 7.4 AER Final Decision - Forecast input price change (per cent)**

	2016–17	2017–18	2018–19	2019–20	2020–21
<b>Input price change</b>	0.31	0.45	0.56	0.75	0.91

Source: AER analysis

Business SA also stated the AER's draft decision allowing AGN real labour cost increases is at odds with AGN's forecast approach for new estate connections where the AER did not consider that applying construction and labour escalation to the contractor labour component of unit rates for mains, services and meters would result in estimates arrived at on a reasonable basis.<sup>27</sup> Business SA noted the AER's draft decision stated the underlying contracts do not provide for any real construction, labour or material escalation.<sup>28</sup>

We do not consider our draft decision in respect of new estate connections at odds with the application of input price escalation to internal labour. This is because these contracts are for the provision of connection services rather than for the provision of a unit of labour. AGN's input price growth for its internal labour is based on the WPI for EGWWS sector. It represents the price AGN pays for a unit of labour and is not productivity adjusted. We consider AGN's contractor price growth reflects the price it pays after productivity growth and is effectively productivity adjusted. Therefore, labour cost escalation is not appropriate for deriving forecasts for contracted services.

### 7.4.3.3 Output change

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

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.

AGN accepted our draft decision on output growth in its revised proposal.<sup>29</sup> We have updated our customer number and throughput forecasts in our final decision.<sup>30</sup>

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<sup>27</sup> Business SA, *Submission on AER draft decision and AGN revised proposal*, 29 January 2016, p. 3.

<sup>28</sup> Business SA, *Submission on AER draft decision and AGN revised proposal*, 29 January 2016, p. 3; See also AER, *Draft Decision: Australian Gas Networks (SA) Access Arrangement 2016-21, Attachment 9*, November 2015, pp. 23–24.

<sup>29</sup> Australian Gas Networks, *Revised Access Information for Australian Gas Networks' South Australian Natural Gas Distribution Network, Attachment 7.8: Response Draft Decision Operating Expenditure*, January 2016, p. 9.

<sup>30</sup> See Attachment 13 - Demand, of this decision. We note that the throughput numbers which we used in the draft decision opex model only included demand for Tariff V (residential and commercial) customers. However, the updated forecast used in our final decision also includes demand for Tariff D (industrial customers).

Table 7.5 sets out the total output growth factor applied in our alternative total opex forecast.

**Table 7.5 AER final decision - Output growth (per cent)**

	2016–17	2017–18	2018–19	2019–20	2020–21
Output growth factor	0.27	-1.06	-0.33	-0.22	-0.13

Source: AER analysis.

#### 7.4.3.4 Productivity change

Productivity is a measure of how well a business 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 at which total opex needs to increase to deliver the same level of services. The productivity measure accounts for labour productivity, economies of scale, and the effect of industry wide technical change. An example of productivity change is increased efficiency due to better use of technology such as IT.

In our draft decision we applied a 0.50 per cent productivity adjustment in each year of the access arrangement period.<sup>31</sup> In the absence of a specific forecast by AGN we based our alternative productivity adjustment factor on the forecasts developed by ACIL Allen Consulting for ActewAGL. This was the most up to date productivity forecast for a gas distribution business that was available to us at the time.<sup>32</sup>

AGN did not accept the AER's draft decision on the application of a productivity adjustment factor. AGN's view is that the AER should not apply a productivity factor for the following reasons:<sup>33</sup>

- The labour cost inflator does not compensate AGN for forecast productivity improvements as it does not capture all drivers of productivity growth.
- A forecast of productivity growth cannot be arrived at on a reasonable basis as required by Rule 74 of the NGR. The AER's use in the draft decision of cost function analysis to determine and apply a forecast of productivity growth was not appropriate and did not result in a reasonable forecast. This is because this type of

<sup>31</sup> AGN in its initial access arrangement proposal did not apply a productivity factor to its opex forecast. In our draft decision we considered AGN could reasonably expect productivity growth in the 2016-21 period so we developed an alternative productivity adjustment factor.

<sup>32</sup> AER, *Draft Decision: Australian Gas Networks (SA) Access Arrangement 2016-21, Attachment 7*, November 2015, pp. 7-37 to 7-38.

<sup>33</sup> Australian Gas Networks, *Revised Access Information for Australian Gas Networks' South Australian Natural Gas Distribution Network, Attachment 7.8: Response Draft Decision Operating Expenditure*, January 2016, pp. 9–16.

analysis has various limitations relating to data comparability, model specifications and environmental variables.<sup>34</sup>

- Forecast productivity growth does not comply with the AER's forecast assessment principles and AGN, therefore, cannot accept the AER's application of a productivity adjustment.
- AGN has already absorbed significant opex costs in its revised proposal by accepting the AER's decision on most step changes. The cost of these step changes effectively acts as an implicit productivity adjustment of 0.7 per cent per annum. Therefore, AGN considers it is not necessary for the AER to apply an additional productivity adjustment.
- The AER has applied a productivity adjustment that is not specific to AGN and is, therefore, not arrived at on a reasonable basis as required by Rule 74 of the NGR. AGN considers that the forecast productivity gains of an alternative gas distribution business have little relevance to the forecast productivity performance of AGN, particularly given no AGN forecast data is used in developing the adjustment factor.

AGN submitted any productivity adjustment factor applied by the AER should be based upon AGN data. AGN engaged ACIL Allen to develop a forecast productivity adjustment using AGN specific data – in each scenario a negative productivity factor was determined.<sup>35</sup>

However, AGN stated it did not apply a negative productivity adjustment in its revised proposal as this would result in an increase to AGN's forecast opex. AGN stated this reflected their view that the productivity adjustment cannot be arrived on a reasonable basis and cannot meet the requirements in Rule 74 of the NGR. AGN proposed a zero productivity adjustment noting that implicit in its decision not to apply a negative productivity adjustments is the expectation it will generate productivity improvements equivalent to \$22 million (derived from the benefits of its proposed capex program).<sup>36</sup>

We received two submissions on our draft decision which discussed the productivity adjustment factor. SACOSS supported our draft decision and considered it reasonable for the AER to examine and make judgments about the scope and value of possible

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<sup>34</sup> AGN engaged Huegin to review the AER's approach to the application of the productivity adjustment. Huegin's view was that the AER's methodology had a number of limitations. See Huegin, *The use of economic benchmarking in the gas distribution industry; Review on the application of an opex productivity factor for Australian Gas Networks*, December 2015. (Attachment 7.13 to Australian Gas Networks, *Revised Access Information for Australian Gas Networks' South Australian Natural Gas Distribution Network*, January 2016)

<sup>35</sup> See ACIL Allen Consulting, *Opex Partial Productivity Forecasts: Australian Gas Networks Limited*, January 2016, (Attachment 7.14 to Australian Gas Networks, *Revised Access Information for Australian Gas Networks' South Australian Natural Gas Distribution Network*, January 2016).

<sup>36</sup> Australian Gas Networks, *Revised Access Information for Australian Gas Networks' South Australian Natural Gas Distribution Network, Attachment 7.8: Response Draft Decision Operating Expenditure*, January 2016, pp. 16–17.

productivity improvements based on the experience of other similar entities.<sup>37</sup> Uniting Care Australia also supported the application of a productivity adjustment factor noting it was the basis of incentive based regulation.<sup>38</sup>

However, HoustonKemp (on behalf of AGN) did not agree with our draft decision on the productivity adjustment factor and considered it would give rise to an allowance for operating expenditure that is less than that which would be incurred by a prudent service provider acting efficiently.<sup>39</sup> HoustonKemp stated that in its view the total opex forecast in draft decision did not meet the NGO requirements.<sup>40</sup>

We have reviewed the additional information AGN provided in its revised proposal and the relevant submissions we received. Based on a review of the material and our own analysis, we were unable to identify a better productivity factor estimate than that proposed by AGN. Therefore, we have concluded that it is reasonable to accept AGN's proposal to apply a zero productivity factor for the forecast period. We consider this is the best estimate available in the circumstances.

Table 7.6 contains our final decision on the productivity adjustment to be applied in the rate of change factor.

**Table 7.6 AER final decision - Productivity change forecast (per cent)**

	2016–17	2017–18	2018–19	2019–20	2020–21
AER's productivity change	0.00	0.00	0.00	0.00	0.00

Source: AER analysis.

#### 7.4.4 Step changes

In some instances, a service provider may face changes to opex not accounted for in our estimate of base opex or the rate of change. We assess each step change on its merits. The test we apply is whether the step change is needed for the total opex forecast to comply with the opex criteria. It is not enough to demonstrate an efficient cost will be incurred for an activity that was not previously undertaken or opex for a particular cost category is expected to rise. As a result, step changes generally relate to a new obligation or some change in the service provider's operating environment beyond its control, such as new legislation or regulations.

<sup>37</sup> SACOSS, *Submission to the AER in Response to AGN's Revised Regulatory Proposal for the 2016 - 2021 Access Arrangement*, February 2016, p. 8.

<sup>38</sup> Uniting Care Australia, *Submission to Australian Energy Regulator Re: AGN SA Access Arrangement 2016-21, Draft Decision*, March 2016, p. 7.

<sup>39</sup> HoustonKemp, *Australian Gas Networks: AER gas price review*, 4 February 2016, p. 35 (Attachment to Australian Gas Networks, *Submission on Australian Gas Networks (SA) - Access Arrangement 2016-21*, February 2016).

<sup>40</sup> HoustonKemp, *Australian Gas Networks: AER gas price review*, 4 February 2016, p. 35 (Attachment to Australian Gas Networks, *Submission on Australian Gas Networks (SA) - Access Arrangement 2016-21*, February 2016).

In our draft decision we rejected all the step changes proposed by AGN. However, we did accept, as step changes, the reclassification of three capex projects as opex.<sup>41</sup>

AGN largely accepted our draft decision on step changes on the basis its proposed capex program would deliver benefits over the next access arrangement period and provide it with the capacity to absorb the costs of the proposed step changes.<sup>42</sup>

However, AGN re-proposed the inlet data capture step change with an estimated cost of \$1.7 million (\$2015–16). In addition, AGN re-proposed its Ongoing HDPE risk management step change, conditional on the AER's final decision on its capex project (SA60).<sup>43</sup> AGN also accepted the AER's draft decision to re-categorise two out of three projects to opex.

We assessed AGN's revised proposal to determine whether its proposed step changes should be included in our total opex forecast. Table 7.7 shows AGN's proposed step change and our final decision on them. Our reasons are provided below.

**Table 7.7 AER final decision on step changes (\$million, 2015–16)**

Step change	Amount	Final decision
Inlet data capture (SA44)	1.7	0.0
Ongoing HPDE risk management (SA54) (re-proposed in the event the AER does not accept capex project (Business Intelligence-SA60))	3.2	0.0
Total step changes	4.9	0.0

Source: Australian Gas Networks, *Revised Access Information for Australian Gas Networks' South Australian Natural Gas Distribution Network, Attachment 7.8: Response Draft Decision Operating Expenditure*, January 2016; AER analysis. Numbers may not add up due to rounding.

#### 7.4.4.1 Inlet data capture

In our draft decision, we did not include the inlet data capture step change in our opex forecast on the basis it was a discretionary activity aimed at developing more efficient business practices and, in such circumstances, we expect service providers to bear the costs of efficiency improvements and make efficient trade-offs.<sup>44</sup>

<sup>41</sup> AER, *Draft Decision: Australian Gas Networks (SA) Access Arrangement 2016-21, Attachment 7*, November 2015, pp. 7-17 to 7-31.

<sup>42</sup> Australian Gas Networks, *Revised Access Information for Australian Gas Networks' South Australian Natural Gas Distribution Network, Attachment 7.8: Response Draft Decision Operating Expenditure*, January 2016, p. 5.

<sup>43</sup> AGN advised that it would not seek to include this opex step change if the AER accepted the proposal of various capex projects such as the Business Intelligence Initiative (SA60). See Australian Gas Networks, *Revised Access Information for Australian Gas Networks' South Australian Natural Gas Distribution Network, Attachment 7.8: Response Draft Decision Operating Expenditure*, January 2016, p. 7.

<sup>44</sup> AER, *Draft Decision: Australian Gas Networks (SA) Access Arrangement 2016-21, Attachment 7*, November 2015, pp. 7- 22 to 7-23.

AGN re-proposed the inlet data capture step change, stating that the project was not discretionary but driven by public safety and risk reduction.<sup>45</sup> The project is designed to capture geographical information relating to the inlet services of the remaining 9,800 industrial and commercial (I&C) sites and the 3,300 highest risk multi-dwelling development sites for which there is currently no inlet service information available.<sup>46</sup> AGN proposed to implement the project in the last three years of the next access arrangement period to align with the roll-out of the new GIS system. AGN also noted the project is an expansion of an initiative approved by the AER for the current access arrangement period.<sup>47</sup>

We maintain our draft decision position and do not accept the inlet data capture project as a step change. In reaching this view, we have considered the additional information provided by AGN and the submissions we received on our draft decision and AGN's revised proposal.

Uniting Care Australia supported our draft decision on AGN's proposed step changes on the basis they were part of the opex of a prudent business.<sup>48</sup> Both SACOSS and ECCSA in their submissions supported our draft decision on the data inlet capture step change. ECCSA acknowledged that the location of service inlets is important but questioned why after more than 15 years of regulation, AGN still did not know where it connects to its customers.<sup>49</sup> ECCSA stated there had been no change in laws and regulation in relation to the exact location of customer interfaces with AGN assets. Therefore, ECCSA could not see why this issue had been raised as a step change when it is and has always been good industry practice to know where a provider interfaces with its customer.<sup>50</sup> SACOSS considered that the cost of the inlet data capture project was sufficiently small relative to the total opex allowance over the 2016–21 access arrangement period of \$358.8m that it might be best considered part of the general opex allowance.<sup>51</sup>

The Consumer Challenge Panel also agreed with this aspect of the AER's draft decision, stating they expected that a prudent and efficient network business operator

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<sup>45</sup> Australian Gas Networks, *Revised Access Information for Australian Gas Networks' South Australian Natural Gas Distribution Network, Attachment 7.8: Response Draft Decision Operating Expenditure*, January 2016, p. 6.

<sup>46</sup> Inlet services carry gas from the pipe in the street to the customer's property. The project in the current access arrangement period captured inlet service details for approximately 5,000 I&C sites and 3,250 unit development sites - see Wilson Cook & Co, *Review of Expenditure of Queensland and South Australian Gas Distributors: Envestra Limited (South Australia) (Public)*, December 2010, p. 58.

<sup>47</sup> Australian Gas Networks, *Revised Access Information for Australian Gas Networks' South Australian Natural Gas Distribution Network, Attachment 7.8: Response Draft Decision Operating Expenditure*, January 2016, p. 6.

<sup>48</sup> Uniting Care Australia, *Submission to Australian Energy Regulator Re: AGN SA Access Arrangement 2016-21, Draft Decision*, March 2016, p. 7.

<sup>49</sup> Energy Consumer's Coalition of South Australia, *Response to the AER Draft Decision on AGN's AA 2016 Revenue Reset*, February 2016, p. 29.

<sup>50</sup> Energy Consumer's Coalition of South Australia, *Response to the AER Draft Decision on AGN's AA 2016 Revenue Reset*, February 2016, p. 29.

<sup>51</sup> SACOSS, *Submission to the AER in Response to AGN's Revised Regulatory Proposal for the 2016 - 2021 Access Arrangement*, February 2016, p. 8.

capturing information about the location and condition of its assets was an ongoing 'business as usual' activity, and should not be considered as a step change.<sup>52</sup>

We acknowledge AGN's proposed data inlet capture project will improve the safety of services by facilitating access in the event of an emergency. This, in turn, will reduce the risk of damage to AGN's network and third parties. We also recognise that this project is prudent and consistent with good industry practice.<sup>53</sup> However, as there are no new regulatory obligations or other exogenous circumstances underpinning AGN's proposal to capture inlet data, we maintain our draft decision position that this project is discretionary.

Generally, an efficient base level of opex (rolled forward each year with an appropriate rate of change) is sufficient for a prudent and efficient service provider to meet all existing regulatory and service obligations. In our view, AGN's base opex already includes the cost of maintaining the quality, safety, reliability and security of supply of AGN's gas system. Therefore, while we do not accept this step change, we consider it is open to AGN to re-prioritise its opex budget to accommodate expenditure on this project.<sup>54</sup>

#### 7.4.4.2 Ongoing HDPE risk management

In our draft decision, we did not accept the ongoing HDPE risk management project (SA54) as a step change on the basis that AGN had not provided sufficient information appropriately quantifying the risks upon which the step change was predicated.<sup>55</sup>

In its revised proposal AGN indicated the proposed Business Intelligence Initiative (SA60) project will provide it with a similar capability as sought by SA54. This capex project involves integrating a business intelligence toolset into AGN's enterprise business applications leading to improved data quality, streamlined reporting and greater access to information to enable more information and efficient decisions. It is estimated to cost \$8.7 million (\$2015–16).<sup>56</sup> AGN, in its revised proposal, stated that if

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<sup>52</sup> Consumer Challenge Panel - Supplementary advice to AER from Consumer Challenge Panel sub-panel 8 AGN, 31 Mar 2016, pp. 2–3.

<sup>53</sup> We expressed a similar view when considering the inlet data capture initiative proposed by AGN's predecessor (Envestra) for the current access arrangement period see AER, *Draft Decision: Envestra Ltd - Access arrangement proposal for the SA gas network 1 July 2011 – 30 June 2016*, February 2011, p. 161; Wilson Cook & Co, *Review of Expenditure of Queensland and South Australian Gas Distributors: Envestra Limited (South Australia) (Public)*, December 2010, p. 58.

<sup>54</sup> We have not conducted a detailed analysis of the costs associated with this step change.

<sup>55</sup> The project relates to the provision of additional engineering, pipe sampling and testing resources to mitigate the risks associated with older parts of the HDPE network. See AER, *Draft Decision: Australian Gas Networks (SA) Access Arrangement 2016-21, Attachment 7*, November 2015, pp. 27–28.

<sup>56</sup> Australian Gas Networks, *Revised Access Information for Australian Gas Networks' South Australian Natural Gas Distribution Network, Attachment 7.1A: Response Draft Decision Business Cases for Operational Expenditure and Capital Expenditure*, January 2016.

SA60 was accepted by the AER the ongoing HDPE risk management project (SA54) step change would not be required.<sup>57</sup>

We have not included the ongoing HDPE risk management project in our total opex forecast. As discussed in attachment 6, we have accepted the Business Intelligence Project (SA60)<sup>58</sup> and, therefore, we have not re-assessed AGN's ongoing HDPE risk management project.

#### 7.4.4.3 Capex projects re-categorised as opex

In our draft decision we re-categorised three capex projects as opex. We adjusted our base year opex for two of these projects.<sup>59</sup> In relation to the third project (Valve Corrosion Protection (SA09)) we indicated in our draft decision that we were not satisfied that AGN, acting as a prudent and efficient service provider, would need to seek additional funding from consumers for this project above an efficient base amount of opex.<sup>60</sup>

AGN's revised proposal accepted the re-categorisation of the first two projects to opex and their incorporation into the base year as set out in our draft decision.<sup>61</sup> However, AGN did not accept the re-categorisation of the Valve Corrosion Protection (SA09) project. AGN submitted this project should be categorised as capex because the project involves work that is major and involves infrequent repair rather than routine maintenance.<sup>62</sup>

Following our review of AGN's revised proposal, we sought further clarification from AGN on its categorisation of this project in light of its treatment as opex in the current access arrangement period.<sup>63</sup> In response to our information request, AGN reviewed its categorisation of this project and agreed to accept the AER's draft decision to categorise this project as opex.<sup>64</sup> AGN confirmed the amount of \$397,308 should be

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<sup>57</sup> Australian Gas Networks, *Revised Access Information for Australian Gas Networks' South Australian Natural Gas Distribution Network, Attachment 7.8: Response Draft Decision Operating Expenditure*, January 2016, p. 7.

<sup>58</sup> AER, *Final Decision: Australian Gas Networks (SA) Access Arrangement 2016-21, Attachment 6 – Capital Expenditure*, May 2016, section 6.4.2.4.

<sup>59</sup> These two projects are: the transmission pressure pipeline corrosion under heat shrink sleeves project (SA21a) and the non-compliant meters inside buildings project (SA32). See AER, *Draft Decision: Australian Gas Networks (SA) Access Arrangement 2016-21, Attachment 7*, November 2015, pp. 30–31.

<sup>60</sup> See AER, *Draft Decision: Australian Gas Networks (SA) Access Arrangement 2016-21, Attachment 7*, November 2015, pp. 7- 29 to 7-30.

<sup>61</sup> Australian Gas Networks, *Revised Access Information for Australian Gas Networks' South Australian Natural Gas Distribution Network, Attachment 7.8: Response Draft Decision Operating Expenditure*, January 2016, p. 7.

<sup>62</sup> Australian Gas Networks, *Revised Access Information for Australian Gas Networks' South Australian Natural Gas Distribution Network, Attachment 7.8: Response Draft Decision Operating Expenditure*, January 2016, p. 7; and Australian Gas Networks, *Revised Access Information for Australian Gas Networks' South Australian Natural Gas Distribution Network, Attachment 7.10: Response to Draft Decision: Advice regarding opex versus capex classification – A report by Deloitte*, January 2016.

<sup>63</sup> At the time of the previous gas access arrangement review, AGN (then Envestra) accepted the classification of this work as opex.

<sup>64</sup> Australian Gas Networks, *Response to Information Request 034*, 4 February 2016.



removed from conforming capex and adjusted the opex totals for 2013–14, 2014–15 and 2015–16 to reflect the reallocation of this project to opex.<sup>65</sup>

We accept AGN's adjustment to its current period opex and have updated our opex model to reflect AGN's correction in our final decision.<sup>66</sup>

## 7.4.5 Category specific forecasts

### *Unaccounted for gas*

In our draft decision we included in our total opex forecast a category-specific forecast for Unaccounted for gas (UAFG) expenditure.<sup>67</sup> We also applied a 'true-up' adjustment in the tariff variation mechanism to address the considerable uncertainty around forecast gas prices in the 2016–21 period.<sup>68 69</sup>

AGN, in its revised proposal, accepted our position and provided updated UAFG forecast volumes to account for changes in its revised mains replacement program.<sup>70</sup> Based upon these updated volumes, AGN's revised forecast of UAFG costs totalled \$59.85 million (\$2015–16), around 17 per cent of total opex.

We assessed AGN's revised proposal to determine whether its category-specific forecast for UAFG should be included in our total opex forecast. Our forecast of UAFG costs is higher than that proposed by AGN in its revised proposal. Our forecast is based on revised (lower) UAFG quantities and higher UAFG prices which AGN provided to us in response to an information request.<sup>71</sup> These revised forecasts were based on the most up to date data available.

Table 7.8 contains AGN's revised forecasts for UAFG together with our final decision. Our reasons for our decision on UAFG are provided below.

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<sup>65</sup> Australian Gas Networks, *Response to Information Request 034A*, 17 February 2016.

<sup>66</sup> For the 2014-15 (base) year this led to an increase of \$0.206 million (\$2015-16). We note this omission also led AGN to correct its ECM carryover amount calculations. See Australian Gas Networks, *Response to Information Request 034A*, 17 February 2016.

<sup>67</sup> Our draft decision did not accept the specific category forecasts AGN proposed for the Network Management Fee, insurance and ancillary reference services. Instead, we incorporated all these categories into the base year.

<sup>68</sup> AER, *Draft Decision: Australian Gas Networks (SA) Access Arrangement 2016-21, Attachment 7*, November 2015, pp. 7-40 to 7-42.

<sup>69</sup> We understand that the Australian Energy Market Operator's (AEMO) review of UAFG arrangements is continuing and is unlikely to be completed before AGN's forthcoming access arrangement period commences. Consistent with our draft decision we note that if the review results in the removal of the obligation on AGN to supply UAFG, the opex impact can be addressed through the pass through provisions in AGN's access arrangement for the 2016–21 period. See AER, *Draft Decision: Australian Gas Networks (SA) Access Arrangement 2016-21, Attachment 7*, November 2015, pp. 7-40 to 7-41.

<sup>70</sup> Australian Gas Networks, *Revised Access Information for Australian Gas Networks' South Australian Natural Gas Distribution Network, Attachment 7.8: Response Draft Decision Operating Expenditure*, January 2016, pp. 3–4.

<sup>71</sup> Australian Gas Networks, *Response to AER Information Request 047* [email to AER], 18 March 2016.

**Table 7.8 AGN revised proposal and AER final decision - Category specific forecasts UAFG (\$2015–16)**

Forecast	2016–17	2017–18	2018–19	2019–20	2020–21	Total (2016–21)
<b>AGN revised proposal</b>						
UAFG Price \$/GJ	8.81	9.95	10.58	10.58	10.58	
UAFG Volume TJ	1269	1225	1187	1149	1113	5943
Total \$(million)	11.17	12.19	12.56	12.16	11.77	59.85
<b>AER final decision</b>						
UAFG price \$/GJ	11.25	11.25	11.25	11.25	11.25	
UAFG volume TJ	1177	1148	1118	1080	1029	5552
Total \$(million)	13.24	12.91	12.57	12.15	11.57	62.45

Source: Australian Gas Networks, *Response to AER Information Request 047* [email to AER], 18 March 2016; AER analysis. Numbers may not add up due to rounding.

#### 7.4.5.1 UAFG true-up adjustment

Our final decision includes a specific UAFG true-up adjustment in the tariff variation mechanism as set out in Attachment 11 of our draft decision. AGN accepts our proposed application of the true-up adjustment.<sup>72</sup>

SACOSS and Origin supported our true-up adjustment.<sup>73</sup> However, ECCSA expressed concern about our approach to the true-up process, in particular, that the cost of gas will be on an as-incurred basis.<sup>74</sup> ECCSA's view is that the true-up adjustment imposes no pressure on AGN to secure the lowest possible price for gas, and gas providers will

<sup>72</sup> AGN, in its revised proposal, suggested two amendments to the UAFG true-up adjustment formula. We discuss AGN's proposed amendments in Attachment 11 of this final decision.

<sup>73</sup> SACOSS, *Submission to the AER in Response to AGN's Revised Regulatory Proposal for the 2016 - 2021 Access Arrangement*, February 2016, p. 9; Origin Energy, *Submission on AGN Revised Access Arrangement*, 4 February 2016, p. 3.

<sup>74</sup> Energy Consumer's Coalition of SA, *Response to the AER Draft Decision on AGN's AA2016 Revenue Reset*, February 2016, pp. 27–28.

act on this knowledge to raise prices.<sup>75</sup> ECCSA recommended using independent benchmark prices set as a comparison rate and incentivising AGN to secure gas at a lower price by sharing any savings below the benchmark.<sup>76</sup>

We understand ECCSA's concern about the true-up adjustment for UAFG prices reducing the incentive for AGN to seek the lowest price for UAFG. However, there are countervailing incentives that will mitigate against ECCSA's concern. Specifically, AGN has an incentive to minimise the price it pays for UAFG as that price will ultimately feed into its tariffs, and overall demand for gas will fall if prices increase. Under a weighted average price cap, an increase in demand will benefit AGN, and therefore it is not in AGN's best interest to accept higher prices for gas where there is no benefit to itself and there are potential longer term negative impacts on demand. Further, the gas market in Adelaide has a number of potential suppliers.<sup>77</sup> This should limit the effectiveness of any particular supplier raising prices on the assumption that AGN will be indifferent to price. Therefore, we do not consider that it is necessary to apply benchmark pricing to provide AGN with an incentive to seek the lowest prices for its UAFG supply contracts.

The true-up adjustment mechanism has been revised to correct the mathematical representation of the mechanism. This is discussed in Attachment 11 of this final decision.<sup>78</sup> In response to a request from the AER, AGN provided a revised UAFG price forecast, which we have applied in our derivation of forecast UAFG costs. This revised forecast will be the reference price for the true-up mechanism.<sup>79</sup>

#### 7.4.5.2 UAFG forecast volumes

AGN, as part of its revised proposal, updated UAFG forecast volumes to account for changes in its revised mains replacement program.<sup>80</sup>

A number of submissions raised concerns about the forecast UAFG volumes in AGN's revised proposal. The South Australian Government noted the importance of establishing accurate base levels of UAFG for forecasting purposes in its submission to the AER.<sup>81</sup>

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<sup>75</sup> Energy Consumer's Coalition of SA, *Response to the AER Draft Decision on AGN's AA2016 Revenue Reset*, February 2016, p. 28.

<sup>76</sup> See Energy Consumer's Coalition of SA, *Response to the AER Draft Decision on AGN's AA2016 Revenue Reset*, February 2016, p. 28.

<sup>77</sup> See AEMO's current list of participants registered in the VIC, SA, QLD and NSW/ACT gas markets available on AEMO's website at: <http://www.aemo.com.au/About-the-Industry/Registration/Current-Registration-and-Exemption-lists>.

<sup>78</sup> AER, *Final Decision: Australian Gas Networks (SA) Access Arrangement 2016-21, Attachment 11 – Reference tariff variation mechanism*, May 2016, section 11.4.

<sup>79</sup> Australian Gas Networks, *Response to AER Information Request 047* [email to AER], 18 March 2016.

<sup>80</sup> Australian Gas Networks, *Revised Access Information for Australian Gas Networks' South Australian Natural Gas Distribution Network, Attachment 7.8: Response Draft Decision Operating Expenditure*, January 2016, p. 4.

<sup>81</sup> Government of South Australia, *AGN Access Arrangement : Submission to Draft Decision and Revised Proposal*, 24 February 2016, p. 3.

ECCSA noted AGN increased its forecast UAFG from the levels included in the initial regulatory proposal.<sup>82</sup> Based on information provided in AGN's initial proposal, ECCSA suggested that approximately 20 per cent per cent of UAFG is from damaged mains with the other 80 per cent coming from many other causes.<sup>83</sup> ECCSA's view is that there are a number of factors contributing to UAFG volumes that are within the control of AGN, and it questions why consumers should reimburse AGN for UAFG that is within its control.<sup>84</sup>

Reflecting ECCSA's concern, the AER queried why UAFG attributable to other causes (that is, not leakage from the distribution network) has not been reduced in the UAFG forecast. AGN advised that after leakage, the major sources of other UAFG are measurement error due to tolerances on meters and temperature differences. Its mitigation measures do not impact these sources of UAFG, and hence the forecast of other UAFG is not influenced by its mitigation activities.<sup>85</sup>

SACOSS noted that the estimated UAFG volumes adopted in the AER's draft decision are likely to be overstated given the impact of the mains replacement program on the volume of UAFG.<sup>86</sup> SACOSS accepted that if the AER ultimately approves a lower amount for mains replacement than AGN proposed in its revised proposal, then AGN's UAFG estimates could be expected to be higher.<sup>87</sup>

In response to a request from the AER, AGN provided a revised UAFG volume forecast, taking into account more recent UAFG data for 2014–15, and a further revision to the mains replacement program accepted by the AER in this access arrangement decision. The revised total UAFG volumes are 391 TJ less than AGN's revised proposal, and decrease from 1258 TJ in 2014–15 to 1029 TJ in 2020–21.<sup>88</sup> We have accepted the updated forecast, on the basis that it relies on the most recent actual data and reflects the revised mains replacement program contained in this final decision.

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<sup>82</sup> Energy Consumer's Coalition of SA, *Response to the AER Draft Decision on AGN's AA2016 Revenue Reset*, February 2016, p. 28.

<sup>83</sup> Energy Consumer's Coalition of SA, *Response to the AER Draft Decision on AGN's AA2016 Revenue Reset*, February 2016, p. 28.

<sup>84</sup> Energy Consumer's Coalition of SA, *Response to the AER Draft Decision on AGN's AA2016 Revenue Reset*, February 2016, p. 28.

<sup>85</sup> Australian Gas Networks, *Response to AER Information Request 047* [email to AER], 18 March 2016.

<sup>86</sup> SACOSS, *Submission to the AER in Response to AGN's Revised Regulatory Proposal for the 2016 - 2021 Access Arrangement*, February 2016, p. 9.

<sup>87</sup> SACOSS, *Submission to the AER in Response to AGN's Revised Regulatory Proposal for the 2016 - 2021 Access Arrangement*, February 2016, p. 9.

<sup>88</sup> Australian Gas Networks, *Response to AER Information Request 047* [email to AER], 18 March 2016.