



DRAFT DECISION
Australian Gas Networks
Access Arrangement
2016 to 2021

Attachment 7 – Operating
expenditure

November 2015

© Commonwealth of Australia 2015

This work is copyright. In addition to any use permitted under the Copyright Act 1968, all material contained within this work is provided under a Creative Commons Attributions 3.0 Australia licence, with the exception of:

- the Commonwealth Coat of Arms
- the ACCC and AER logos
- any illustration, diagram, photograph or graphic over which the Australian Competition and Consumer Commission does not hold copyright, but which may be part of or contained within this publication. The details of the relevant licence conditions are available on the Creative Commons website, as is the full legal code for the CC BY 3.0 AU licence.

Requests and inquiries concerning reproduction and rights should be addressed to the:

Director, Corporate Communications
Australian Competition and Consumer Commission
GPO Box 4141, Canberra ACT 2601

or publishing.unit@acc.gov.au.

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne Vic 3001

Tel: (03) 9290 1444

Fax: (03) 9290 1457

Email: AERInquiry@aer.gov.au

Note

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

The draft decision includes the following documents:

Overview

Attachment 1 – Services covered by the access arrangement

Attachment 2 – Capital base

Attachment 3 – Rate of return

Attachment 4 – 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

Attachment 13 – Demand

Attachment 14 – Other incentive schemes

Contents

Note	7-2
Contents	7-3
Shortened forms	7-4
7 Operating expenditure	7-6
7.1 Draft decision	7-6
7.2 AGN’s proposal	7-6
7.3 AER’s assessment approach	7-10
7.3.1 Building an alternative estimate of total forecast opex	7-10
7.3.2 Interrelationships	7-13
7.4 Reasons for draft decision	7-13
7.4.1 Forecasting method	7-14
7.4.2 Base year opex	7-14
7.4.3 Step changes	7-17
7.4.4 Rate of change	7-31
7.4.5 Category specific forecasts	7-38
7.5 REVISIONS	7-42

Shortened forms

Shortened form	Extended form
AA	Access Arrangement
AAI	Access Arrangement Information
AER	Australian Energy Regulator
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
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
RBA	Reserve Bank of Australia

Shortened form	Extended form
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 of operating, maintenance and other non-capital costs incurred in the provision of gas distribution services. It includes the 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 pipeline.

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

7.1 Draft decision

We are not satisfied that the forecast of total opex AGN proposed complies with the opex criteria and the criteria for forecasts and estimates.¹ We therefore do not accept the forecast of required opex AGN included in its building block proposal. Our estimate of AGN's total required opex for the 2016–21 access arrangement period is outlined in Table 7.1.

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

	2016–17	2017–18	2018–19	2019–20	2020–21	Total
AGN's proposal	68.38	70.58	72.44	72.64	73.39	357.43
AER draft decision	67.66	68.55	68.90	68.61	68.62	342.35
Difference	-0.73	-2.03	-3.54	-4.03	-4.77	-15.09 -4%

Source: AER analysis. Numbers may not add due to rounding.

Note: Excludes debt raising costs.

7.2 AGN's proposal

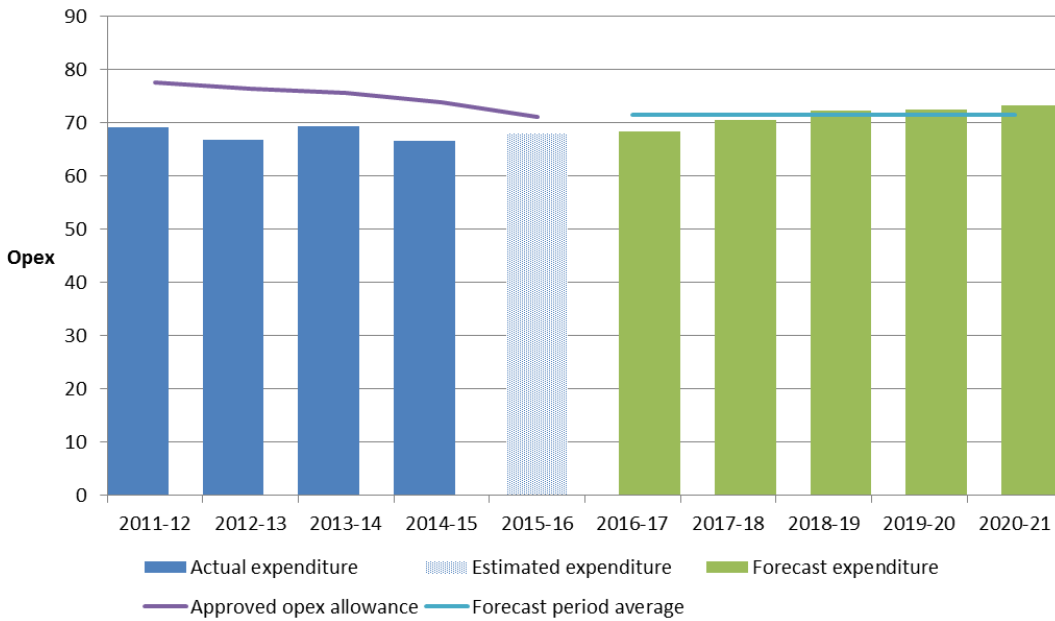
AGN proposed total opex of \$357 million over the next (2016–21) period, equivalent to an average annual opex of \$71 million.² This represents a real increase of around 5 per cent compared to actual opex in the 2011–16 period. AGN noted its total opex in the 2011–16 period is around 9 per cent lower than the allowance approved by the AER.³ AGN's current period and proposed opex is shown in Figure 7.1.

¹ NGR, rr. 74, 91.

² All figures referred to in this attachment are in 2015–16 dollars.

³ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, p. 8.

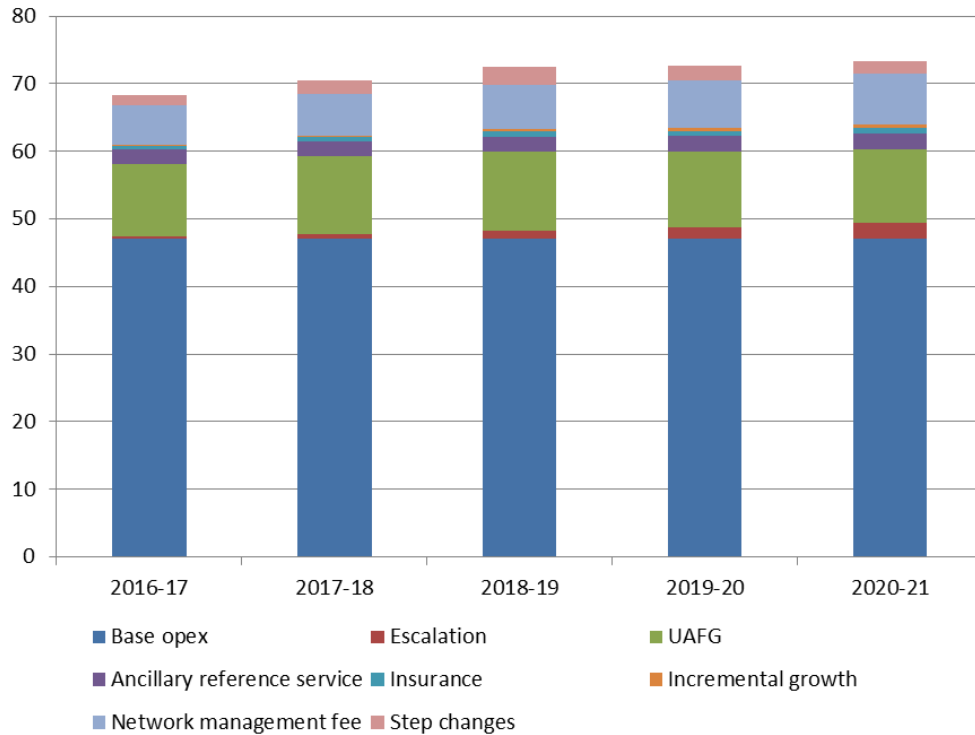
Figure 7.1 AGN's total opex (\$million, 2015–16 dollars)



Source: Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, Attachment 7.7 AGN Opex model, and RIN, July 2015.

AGN proposed a base–step–trend approach to forecast the majority of its opex. Figure 7.2 shows AGN's forecast opex by the elements that make up its forecast.

Figure 7.2 AGN's forecast total opex (\$million, June 2016 dollars)



Source: AER analysis.

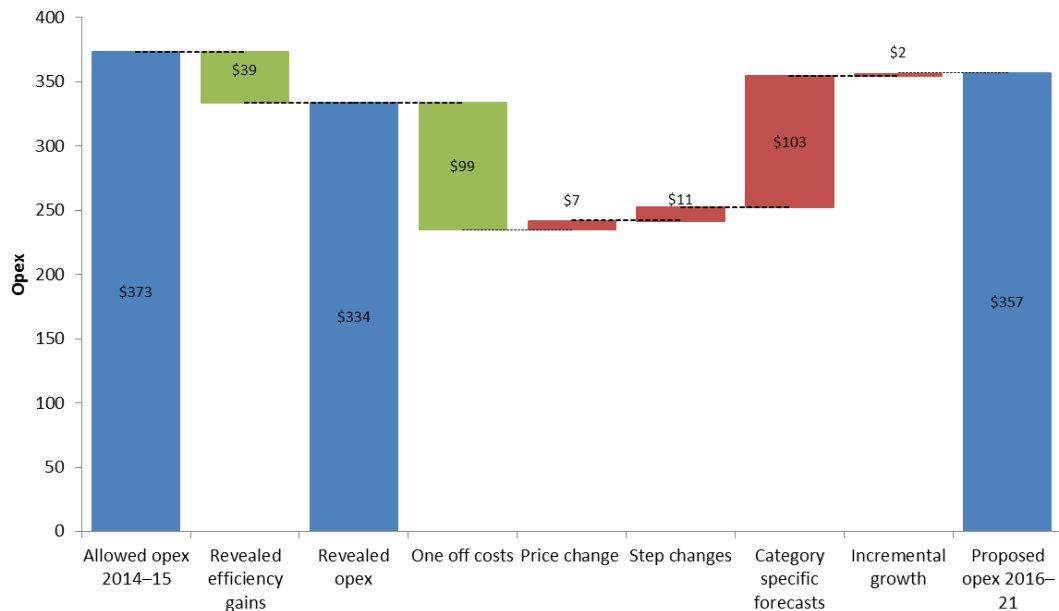
AGN described its opex forecasting method in its Access Arrangement Information.⁴ It used two methods to forecast opex for the 2016–21 access arrangement period:

1. the rate of change approach—applied to the adjusted base year opex amount, which excludes category specific forecasts.
2. category specific forecasts—for four categories of costs.

The rate of change (base-step-trend) forecasting method uses actual expenditure in a base year as an indication of future expenditure because opex is largely recurrent. Base year opex is adjusted to account for changes in the service provider's circumstances that are forecast to affect opex over the 2016–21 period.

The revenue impact of AGN's forecasting method is disaggregated in Figure 7.3. This figure shows the drivers of change between AGN's allowed opex in 2014–15 and its proposed opex allowance for the 2016–21 access arrangement period.

Figure 7.3 Forecasting method impacts (\$million, June 2016 dollars)



Source: AER analysis.

AGN stated it selected 2014–15 as the base year for its forecast because it is the most recent year for which actual information is available.⁵ AGN adjusted its base opex to

⁴ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, attachment 7, Operating expenditure.

⁵ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, p. 111.

remove non–recurrent expenses⁶ and certain specific costs categories. This resulted in base year costs of \$74.7 million, which resulted in base opex of \$373 million for the 2016–21 period. We have assessed AGN’s base opex in section 7.4.2.

AGN’s total opex forecast was built on the adjusted base year, as follows:

- AGN applied real labour cost escalators to develop its opex forecast, but did not apply real escalation to materials input costs. To develop its labour cost escalators AGN used an average of the BIS Shrapnel forecasts in Electricity, Gas, Water and Waste Services industry in South Australia and forecasts prepared by Deloitte Access Economics as part of the AER’s Preliminary decision for SA Power Networks.⁷ AGN’s price escalation added \$7 million to its base opex. We have assessed the impact AGN’s proposed forecast price changes in section 7.4.4.
- AGN proposed step changes of \$11 million over the 2016–21 period⁸ relating to:
 - capex related opex (digital communication capability and IT programs)
 - one–off opex projects (Monarto front–end engineering design study, installation of gas vents on High Density polyethylene (HDPE) mains)
 - projects relating to risk management of HDPE network, inlet data capture and stakeholder education.

We have assessed these proposed step changes in section 7.4.3.

- AGN proposed alternative methods for forecasting certain specific categories of opex on the basis that the base step trend approach did not provide a reasonable forecasting approach. These categories are the network management fee (\$33m), ancillary reference services (\$11m), insurance (\$3.6 m) and unaccounted for gas (\$56 m).⁹ We assess category specific forecasts in section 7.4.5.
- AGN forecast additional opex (growth opex) of \$1.6 million over the 2016–21 period. We have assessed the impact of AGN’s proposed output growth in section 7.4.4.

⁶ The non–recurrent expenditure removed from the base year related to a supply interruption in Port Pirie and Whyalla due to a failure on a transmission pipeline. See Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, p. 114.

⁷ AGN state this averaging approach was adopted by them based upon the AER’s Preliminary Decision for SA Power Networks. See Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, pp. 121–122.

⁸ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, pp. 117–120.

⁹ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, pp. 114–116.

7.3 AER's assessment approach

We decide whether or not to accept a service provider's proposed 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).¹⁰

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:

(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.

¹⁰ Also see NGR, r. 40(2).

- (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 base year expenditure to account for any other forecast cost changes over the 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 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 and 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.¹¹ 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.
- 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

¹¹ 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. Audited accounts are usually available before we make our final decision.

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 access arrangement period. Efficient opex in the forecast access arrangement 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 gas). 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 criteria 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 forecast access arrangement 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.

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 meet the opex criteria. 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.

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.

7.3.2 Interrelationships

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

- the operation of the efficiency carryover mechanism in the 2011–16 period, which provided AGN an incentive to reduce opex throughout the period (section 7.4.2 and attachment 9)
- the impact of forecast demand on forecast output growth in the rate of change (section 7.4.4)
- the inter-relationship between capex and opex, for example, in considering AGN's proposed step changes (section 7.4.3)
- 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 gas consumers identified in the course of AGN's engagement with consumers and in submissions to the AER.

7.4 Reasons for draft decision

We assessed AGN's opex forecast against our alternative estimate of opex. We are not satisfied that AGN's forecast opex for the 2016–21 access arrangement period complies with the opex criteria and the criteria for forecasts and estimates. We also note stakeholders submitted concerns about AGN's proposed opex.¹²

The key areas of difference between our forecast and AGN's forecast of total opex are:

- Rate of change – we consider AGN's forecast of price changes, output growth and productivity changes is not the best estimate of a rate of change 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 have applied a rate of change that takes into account more recent labour cost forecasts and the impact of output growth and productivity changes. We explain the reasons for the difference between our approach in section 7.4.4.
- Step changes – we have not included forecast increases in opex related to step changes proposed by AGN. We consider the changed opex requirements identified

¹² Business SA, p. 7, ECCSA, p. 38, SA Wine Industry Association, p. 3.

by AGN do not relate to new obligations facing AGN or other changes in AGN's circumstances requiring a material increase in opex for the 2016–21 period. We have adjusted base opex for step changes associated with proposed capital programs that we consider should be classified as opex. Our assessment of step changes is in section 7.4.3.

- Category specific forecasts – we do not agree that the category specific forecasts developed by AGN for ancillary reference services, network management fee and insurance result in a total opex forecast that meets the opex criteria. In our alternative opex forecast we have included these categories of expenditure in the base year. Our assessment of category specific forecasts is in section 7.4.5.

We discuss each element of AGN's forecast opex in this attachment.

7.4.1 Forecasting method

We assessed AGN's forecasting method to examine whether this explains why its forecast opex is higher than our alternative estimate. We are satisfied that AGN's forecasting method is not the key driver of the difference. Rather, the key areas of difference arise from differences in the inputs and assumptions that informed the forecasting method.

7.4.2 Base year opex

We are not satisfied AGN's proposed 2014–15 base year expenditure of \$47 million (\$2015–16) is a reasonable estimate for the purpose of forecasting opex for the 2016–21 access arrangement period. This is due to the exclusion of costs for the network management fee, ancillary reference services and insurance from AGN's base year revealed costs. We consider 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.

We have also adjusted base year opex to include expenditure on projects reclassified from capex to opex.

Is base opex efficient?

Our preferred forecasting approach for opex is to rely on the revealed costs of the service provider as a starting point for our alternative opex forecast. We apply an incentive based regulatory framework where service providers are given financial rewards for achieving efficiencies and these are shared with customers through lower opex forecasts over time. AGN has been subject to this incentive framework for a number of access arrangement periods, including the application of an efficiency carryover mechanism for opex. In theory, AGN as a profit maximising firm should reveal its efficient costs over time, and these can be used to forecast opex into the future. Unless we have evidence that the revealed opex in a proposed base year is materially inefficient, we use the revealed costs of the service provider for our alternative opex forecast

Unlike with the electricity network service providers, we do not have standardised data for the gas 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 costs. Instead, we primarily rely on analysis of AGN's historical trends and the gas service provider productivity analysis which AGN submitted as part of its regulatory proposal.¹³

The Consumer Challenge Panel (CPP) asked us to confirm the efficiency of the base year by extending the Economic Insights benchmarking or by other means.¹⁴ The Energy Consumers Coalition of SA argued the 2014–15 base year is not efficient and 2013–14 is a better base year as it is the last year of the benchmarking work carried out by Economic Insights.¹⁵ The South Australian Council of Social Service noted AGN had not proposed significant reductions from the base year, and argued that AGN's total opex should be no more than \$329.5 million.¹⁶

We considered benchmarking undertaken by Economic Insights, which was engaged by AGN to assess the efficiency of its base year opex.¹⁷ The Economic Insights report found that AGN has one of the lowest opex costs per customer (that is, on this indicator AGN either equalled or outperformed its peers in the sample). However, while the Economic Insights report suggests that AGN's use of opex inputs is likely to be among the more efficient in the sample it states the comparison does not control for other relevant opex cost drivers and care needs to be taken when drawing inferences.¹⁸

As we do not have data to conduct our own economic benchmarking or category analysis to assess the efficiency of the revealed base year, the only alternative assessment approach would be to undertake a detailed bottom–up assessment of AGN's base year costs. This is an intrusive and resource–intensive technique. We do not consider that there is any clear evidence of inefficiency to warrant such an an investigation.

Based on this information, we consider there is no evidence to suggest that AGN's revealed costs in its proposed base year are materially inefficient.

¹³ 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).

¹⁴ Consumer Challenge Panel, *Advice to AER from Consumer Challenge Panel sub-panel 8 regarding Australian Gas Networks' SA Access Arrangement 2016–2021 Proposal*, August 2015, p. 9.

¹⁵ Energy Consumers Coalition of South Australia, *Australian Energy Regulator SA Gas Distribution Revenue Reset – a response by the Energy Consumers Coalition of South Australia*, August 2015

¹⁶ South Australian Council of Social Services, *Submission on Australian Gas Networks SA Access Arrangement Proposal 2016–2021*, 21 August 2015, p. 3.

¹⁷ 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).

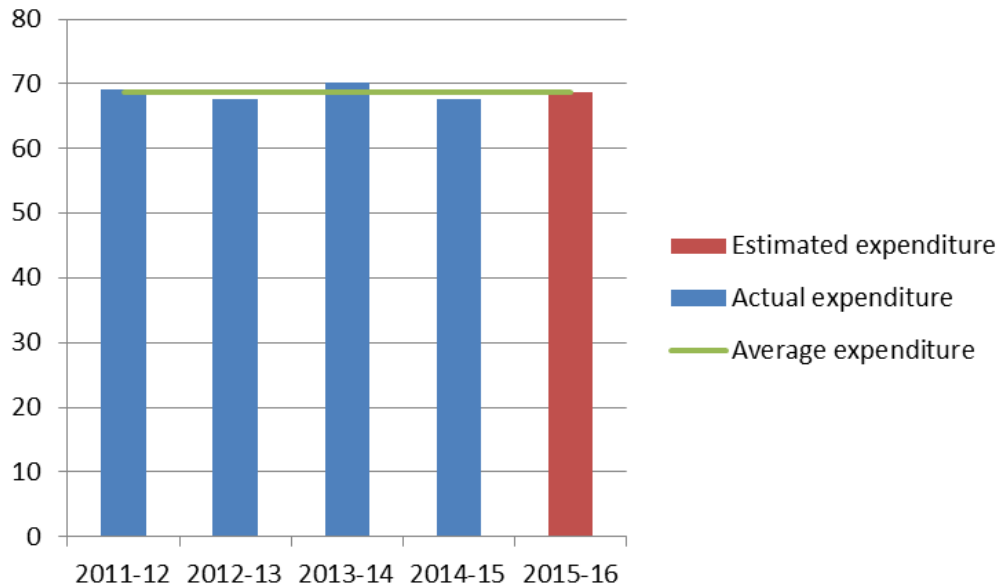
¹⁸ Economic Insights, *Benchmarking Australian Gas Networks' South Australian Business Operating and Capital Costs using Partial Indicators*, report prepared for Australian Gas Networks Limited, 21 May 2015, p. iv. and 8. (Attachment 4.2 to AGN's Access Arrangement Information, July 2015).

Which year should be used as the base year?

AGN chose 2014–15 as its base year. We consider that AGN's proposed base year is a reasonable base year for forecasting opex for the following reasons:

- As opex is generally recurrent, actual costs incurred in 2014–15 are likely 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 available at the time of our final determination.¹⁹ 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 (Figure 7.4).
- AGN's opex was subject to an efficiency sharing 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.
- 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.

Figure 7.4 AGN's total opex, 2011–12 to 2015–16 (\$million, 2015–16)



Source: AER analysis.

¹⁹ At the time of submitting its access arrangement proposal, costs for 2014–15 were an estimate based on actual data for 9 months and estimates for 3 months. AGN will update the 2014–15 estimates at the time of its revised proposal.

We are satisfied AGN's proposed 2014–15 base year is not biased upwards and do not have any evidence to suggest expenditure in the proposed base year is materially inefficient. In our alternative forecast of total opex we have adjusted 2014–15 base year expenditure to include the network management fee, ancillary reference services expenditure and insurance expenditure. We have also included additional opex in the base year relating to reclassified capex project step changes.

7.4.3 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 with 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.

We generally consider 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. We only include a step change in our opex forecast if we are satisfied a prudent and efficient service provider would need an increase in its opex to reasonably reflect the opex criteria.

We forecast opex by applying an annual 'rate of change' to the base year for each year of the forecast access arrangement period. The annual rate of change accounts for efficient changes in opex over time. It incorporates adjustments for forecast changes in output, price and productivity. Therefore, when we assess the proposed step changes we need to ensure that the cost of the step change is not already accounted for in any of those three elements included in the annual rate of change. The following explains this principle in more detail.

For example, a step change should not double count the costs of increased volume or scale compensated through the forecast change in output. We account for output growth by applying a forecast output growth factor to the opex base year. If the output growth measure used captures all changes in output then step changes that relate to forecast changes in output will not be required. To give another example, a step change is not required for the maintenance costs of new office space required due to the service provider's expanding network. The opex forecast has already been

increased (from the base year which includes office maintenance) to account for forecast network growth.²⁰

By applying the rate of change to the base year opex, we also adjust our opex forecast to account for real price increases. A step change should not double count price increases already compensated through this adjustment. Applying a step change for costs that are forecast to increase faster than CPI is likely to yield a biased forecast if we do not also apply a negative step change for costs that are increasing by less than CPI. A good example is insurance premiums. A step change is not required if insurance premiums are forecast to increase faster than CPI because within total opex there will be other items opex where the price may be forecast to increase by less than CPI. If we add a step change to account for higher insurance premiums we might provide a more accurate forecast for the insurance category in isolation; however, our forecast for opex as a whole will be too high.

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. In particular, we have regard to:²¹

- whether there is a change in circumstances that affects the level of expenditure a prudent service provider requires to meet the opex criteria efficiently
- what options were considered to respond to the change in circumstances
- whether the option selected was the most efficient option—that is, whether the service provider took appropriate steps to minimise its expected cost of compliance
- the efficient costs associated with the step change and whether the proposal appropriately quantified all costs savings and benefits
- when the change event occurs and when it is efficient to incur expenditure, including whether it can be completed over the regulatory period
- whether the costs can be met from existing regulatory allowances or from other elements of the expenditure forecasts.

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 use contractors). Step changes should generally relate to a new obligation or some change in the service provider's operating environment beyond its control in order to be expenditure that complies with the opex criteria. It is not enough to simply demonstrate an efficient cost will be incurred for an activity that was not previously undertaken. As noted above, the opex forecasting approach may capture these costs elsewhere.

²⁰ AER, *Explanatory guide: Expenditure assessment forecast guideline*, November 2013, p. 73. See, for example, our decision in the Powerlink determination; AER, *Final decision: Powerlink transmission determination 2012–17*, April 2012, pp. 164–165.

²¹ AER, *Expenditure assessment forecast guideline*, November 2013, p. 11.

Usually increases in costs are not required for discretionary changes in inputs.²² Efficient discretionary changes in inputs (not required to increase output) should normally have a net negative impact on expenditure. For example, a service provider may choose to invest capex and opex in a new IT solution. The service provider should not be provided with an increase in its total opex to finance the new IT since the outlay should be at least offset by a reduction in other costs if it is efficient. This means we will not allow step changes for any short-term cost to a service provider of implementing efficiency improvements. We expect the service provider to bear such costs and thereby make efficient trade-offs between bearing these costs and achieving future efficiencies.

One situation where a step change to total opex may be required is when a service provider chooses an operating solution to replace a capital one.²³ For example, it may choose to lease vehicles when it previously purchased them. For these capex/opex trade-off step changes, we will assess whether it is prudent and efficient to substitute capex for opex or vice versa. In doing so we will assess whether the forecast opex over the life of the alternative capital solution is less than the capex in NPV terms.

We recognise there could be other changes to opex not accounted for through our estimate of base opex and rate of change which is required to meet the opex criteria. For this reason, we assess each proposed step change on its merits. If we are presented with persuasive evidence that a service provider would incur opex that meets the opex criteria in addition to our estimate of base opex (adjusted for our estimate of the rate of change in base opex), then we will include that step change.

However, in identifying other reasons why step changes may occur we consider it is important that the approach to identifying these cost drivers is not subject to bias. The ultimate test we must apply is that step changes are only applied where they are needed for the total opex forecast to reasonably reflect the opex criteria. For instance, we do not consider we should apply a step change just because opex on a particular category is expected to rise. Over a access arrangement period, opex on various categories of opex will both increase and decrease. However, fluctuations in opex at the category level can be managed by a prudent and efficient service provider without increasing its total opex. For instance, a service provider can re-prioritise some areas of opex. Therefore a step change in total forecast opex may not be necessary.

AGN proposed eight step changes totalling \$10.5 million (\$2015–16). We assessed AGN's proposed step changes to determine whether these should be included in our total opex forecast. In our assessment of AGN's proposed capex, we also identified three projects that we have reclassified to opex, and assessed the opex requirements as step changes to base year opex. Table 7.2 sets out AGN's proposed step changes and our draft decision on those step changes.

²² AER, *Expenditure assessment forecast guideline*, November 2013, p. 24.

²³ AER, *Expenditure assessment forecast guideline*, November 2013, p. 24; AER, *Explanatory guide: Expenditure assessment forecast guideline*, November 2013, pp. 51–52.

**Table 7.2 AGN proposed step changes and AER draft decision
(\$million, June 2016)**

Proposed step change	Amount	Draft decision
Development of AGN digital capabilities	1.5	0
IT – Geospatial Information System (GIS) and Mobility	0.9	0
Remote meter reading	0.5	0
Gas vents on high density polyethylene (HDPE) mains	0.9	0
Monarto Front End Engineering and Design (FEED) study	0.3	0
Ongoing risk management HDPE	3.2	0
Inlet data capture	1.7	0
Stakeholder education and advocacy	1.0	0
Capex projects reclassified to opex	5.0	4.7
Total step changes	15.1	4.7

Source: Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, p. 117; and AER analysis.

We have not accepted any step changes that AGN proposed, although we have incorporated two step changes relating to capex projects that have been reclassified to opex into our total opex forecast.

7.4.3.1 Discretionary projects

We consider the following proposed projects to be discretionary expenses, as there are no new regulatory obligations, nor other exogenous circumstances necessitating commencement of these projects:²⁴

- \$1.6 million to develop its digital communication capabilities
- \$0.64 million to implement its new GIS program (which provides a map of network infrastructure)

²⁴ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, p. 118.

- \$0.35 million for its mobility program (mobile communication platform for field workers)
- \$1.7 million for inlet data capture
- \$0.3 million for the Monarto FEED study.

Development of AGN digital capabilities

AGN proposed to consolidate its five websites and build a digital platform for the delivery of online services and communications with stakeholders. AGN stated that the project will bring AGN in line with other gas distributors in Australia and the United Kingdom. It will also deliver operational efficiency through the consolidation of websites and improvements in customer service.²⁵

GIS

AGN stated the current GIS application has been customised to deliver business functionality but as a consequence it is currently unsupported by the application vendor. AGN is proposing a full upgrade of the GIS application. The forecast opex costs include vendor support costs based on a percentage of the licence fee. AGN indicated it has not included internal IT resources required to maintain the system as they are not expected to be materially different. Further, AGN stated there are no additional efficiency savings given the project involves the replacement of an application.²⁶

AGN stated the increasing instability of the existing system, coupled with the difficulty in obtaining support for the system means there is an increasing risk that the current system may fail (or be unavailable for a period of time), which could have implications for public and staff health and safety and meeting regulatory obligations under the Retail Market Procedures.²⁷

Mobility program

The mobility program involves the integration of mobility platforms into the Enterprise IT system. AGN stated the implementation of the program is expected to deliver costs savings resulting from reduced data entry, validation and correction and avoid field data capture and data entry costs. AGN stated the net opex has been calculated to take into account these cost savings.²⁸ It proposed IT support costs for another 2 FTEs to support the mobility program.

²⁵ AGN tendered for a digital specialist to do an initial scope of the work. These costs are provided in the Business Case SA84.

²⁶ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, Attachment 7.1, Business Case SA58, July 2015, pp. 4–9.

²⁷ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, Attachment 7.1, Business Case SA58, July 2015, pp. 4–9.

²⁸ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, Attachment 7.1, Business Case SA59, July 2015, pp. 11–12.

AGN submitted the project will deliver health and safety benefits to the public and its employees through improved response to emergencies and access to accurate asset data such as Dial Before You Dig information.²⁹

Inlet data capture

AGN proposed opex of \$1.7 million to capture geographic details of inlet services to 9,800 existing industrial and commercial customers and 3,300 major unit development sites. The project will facilitate access to inlet services in the event of an emergency.³⁰

AGN stated the capture of inlet service details will occur after the GIS rollout is completed in 2018–19. The work involved will include site visits to the industrial and commercial customers, reviewing hard copy records of multi dwelling sites and publishing inlet service details. AGN's forecast opex included internal labour costs, vehicle lease costs and the cost of software edit licences.³¹

Monarto Front End Engineering and Design (FEED) study

AGN is proposing opex of \$0.3 million for the FEED study to assess the feasibility of extending the network to Monarto (an area where a number of load growth opportunities are expected to be present).³²

Decision

We have approved the capex component of the GIS application,³³ and the development of digital capabilities.³⁴ However, we are not satisfied that AGN would incur incremental increases in total opex from implementing these projects. We did not accept the capex component of the mobility system³⁵ and we also have not included step changes in opex for implementing the mobility system as part of our alternative opex forecast. We also have not included step changes for the Monarto FEED study or inlet data capture.

We consider these initiatives are a discretionary activity aimed at developing more efficient business practices. Our Expenditure Guidelines states:³⁶

²⁹ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, Attachment 7.1, Business Case SA59, July 2015, p. 6.

³⁰ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, p. 120.

³¹ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, Attachment 7.1, Business Case SA44, July 2015, pp. 4–5.

³² Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, p. 119.

³³ See section 6.4.2 of this draft decision for our discussion of the capex component of the GIS application.

³⁴ See section 6.4.2 of this draft decision for our discussion of the capex component of AGN's development of digital capabilities.

³⁵ See section 6.4.2 of this draft decision for our discussion of the capex component of the Mobility program.

³⁶ AER, Expenditure assessment forecast guideline, November 2013, p. 24.

Step changes should not double count the costs of discretionary changes in inputs. Efficient discretionary changes in inputs (not required to increase output) should normally have a net negative impact on expenditure.

Typically, we do not allow step changes for any short-term cost to a service provider of implementing efficiency improvements. We expect the service provider to bear such costs and thereby make efficient trade-offs between these costs and future efficiencies.

In their submissions, the CCP and ECCSA queried whether AGN had accounted for the true extent of savings resulting from implementing the GIS and Mobility programs.³⁷ We expect that these initiatives would, overall, lower the cost of doing business. If they do not lower the cost of doing business, a prudent service provider would not invest in these projects as they would not be considered efficient investments.

For the GIS implementation, AGN stated the upgrade involved the replacement of an existing application and there are no additional efficiency savings associated with the project that can be netted off against the costs.³⁸ We disagree. We consider that there would likely be efficiencies to be gained from moving from an unstable GIS system that is no longer supported by the vendor. The current system exposes AGN to risks, and is increasingly expensive and difficult to maintain compared to a new system that implements standardised national processes.³⁹ Furthermore, AGN has estimated the cost of continuing with its current system is \$12.4 million, significantly higher than the incremental opex requirement.⁴⁰

The Mobility Program is justified by AGN as better systems to help manage assets, automate current paper-based and manual processes, and enable the field work force to deliver improved services. We expect such a program would lower the cost of doing business. For instance, if staff can become mobile then this will increase the number of tasks that can be performed remotely, and reduce the time required to deliver services.

By consolidating AGN's five websites, and building a digital platform for the delivery of online services and communications with stakeholders, AGN stated it will improve its operational efficiency. AGN expects to realise efficiencies through a simplified support and maintenance structure, and improved updating and website management arrangements. It stated establishing the new website as the key service delivery

³⁷ Consumer Challenge Panel, p. 9; Energy Consumers Coalition of SA, pp. 41–43.

³⁸ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, Attachment 7.1, Business Case SA59, July 2015, p. 9.

³⁹ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, Attachment 7.1, Business Case SA59, July 2015, pp. 5–6.

⁴⁰ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, Attachment 7.1, Business Case SA59, July 2015, p. 12.

channel will assist it to communicate more regularly and cost efficiently than using traditional paid media channels such as press, TV and radio.⁴¹

We consider research expenditure relating to extending infrastructure into new market areas should be a normal part of network development activity. Network development is business as usual for a service provider. Therefore, the base opex already includes the cost of an efficient and prudent level of network development assessment processes. Consumers would be paying twice if we include the Monarto FEED study costs as a step change when network development is already accounted for in the base opex forecast. We note ECCSA's submission which considers that the FEED study which will benefit potential new customers should not be paid for by existing customers.⁴²

We therefore expect that there will both productivity gains and cost savings to AGN from each of these projects. We consider that AGN should not be provided with an increase in its total opex to finance the projects, since the costs should be at least offset by future productivity gains and the reductions in other costs if they are efficient.

AGN is subject to an incentive based regulatory framework whereby if it invests an initiative that reduces its costs, it will be rewarded accordingly. Under this framework AGN has an incentive to pursue efficiencies without receiving an increase in funding. If AGN did receive an increase in allowed revenue then consumers would fund efficiency payments to a service provider, as well as funding the full cost of a project. This would be inconsistent with the incentive scheme and the opex criteria that opex expenditure must achieve the lowest sustainable cost of delivering pipeline services.

From time to time, some projects such as replacement of systems or software may lead to higher opex. However, our role is to provide sufficient revenue in total to achieve regulatory obligations. Where there is no new regulatory obligation total opex must be 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.⁴³ Therefore, when considering the cost of replacement of software and systems, we would expect that an incremental increase in the cost of particular systems would reflect the cost to achieve the same level of quality, reliability and security of service. In isolation, there may be programs or projects that cost more from one year to the next. However, when forecasting opex, we do not aggregate the forecast cost associated with individual projects and projects. We forecast total opex.

We are not satisfied that the total opex of an efficient business in providing the same quality, reliability and security of service would be substantially different in the 2016–21 access arrangement period to the base year, 2014–15.

⁴¹ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, Attachment 7.1, Business Case SA84, July 2015, p. 8.

⁴² Energy Consumers Coalition of SA, p 42.

⁴³ NGR, r. 91.

We also note AGN considers the expenditures are necessary to maintain the safety and integrity of services and comply with existing regulatory obligations under the Retail Market Procedures. However, we consider base opex already includes the cost of maintaining the reliability, safety and quality of supply of standard control services. We acknowledge the types of projects and programs of expenditure a service provider undertakes will differ between years and between access arrangement periods. However, we do not consider variation in the expenditure on projects and programs is a reason to increase the revenue AGN can recover from its consumers.

7.4.3.2 Remote meter reading

AGN proposed non–base year opex of \$0.5 million for internal IT support and hosting data for its remote meter reading project.⁴⁴ The project involves the installation of remote meters where manual meters are problematic and trialling technology in new development areas.⁴⁵

AGN stated the project will assist it in meeting the requirement in the Retail Market Procedures that an actual meter read be obtained at least once a year. AGN proposed trialling the installation of automated meter reading on gas meters for customers with poor access or in new subdivisions. The trial will give AGN a better understanding of the costs and benefits of remote read technology and enable it to make a robust decision about the further deployment of the technology. It noted the forecast opex includes internal IT support and hosting data costs and savings from meter reading costs.⁴⁶

The requirement to undertake an actual meter read at least once per year is an existing obligation and is not a new requirement for AGN.⁴⁷ We note that AGN's willingness to pay study found that only 44 per cent of customers were willing to pay \$3 per year for remote meter reading,⁴⁸ which reflects ECCSA's assertion that AGN's consumer engagement does not substantiate AGN's claim that consumers are willing to pay for additional services.⁴⁹ On the basis of this, AGN scaled down its planned roll out of remote meter reading devices to the trial that is proposed now.

Given that most consumers do not support remote meter reading and remote meter reading is not necessary to comply with a new regulatory obligation, we have not included a step change in our alternative opex forecast for AGN. We also have not

⁴⁴ AGN have also proposed capex in relation to the remote meter reading trial. See section 6.4.2 for our discussion on the capex component of this trial.

⁴⁵ AGN, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, p. 119.

⁴⁶ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks' South Australian Gas Distribution Network*, July 2015, Attachment 7.1, Business Case SA64, July 2015, pp. 5–9.

⁴⁷ See AEMO, *Retail Market Procedures (South Australia)* (Version 3.0), May 2011, Rule 149.

⁴⁸ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks' South Australian Gas Distribution Network*, July 2015, p. 63.

⁴⁹ Energy Consumers Coalition of SA, pp. 15–16.

accepted the capex component of the remote meter reading trial.⁵⁰ We consider an efficient base level of opex to be sufficient for a prudent service provider to deliver all existing regulatory obligations.

As outlined in our assessment approach we are required to assess whether total opex complies with the opex criteria.⁵¹ We recognise a service provider may at different times need to spend relatively less or more opex to meet some existing regulatory obligations. However, it is a prudent service provider's responsibility to manage compliance with all of its existing regulatory obligations within its efficient base opex. We consider a prudent service provider can generally do this by adjusting its discretionary opex spending from year to year to most effectively manage those responsibilities. It does not need a step change in opex above an efficient level of base opex.

For instance, while total opex is relatively recurrent, categories of opex, or opex on projects and programs are not recurrent. That means each year a service provider could spend more opex on some areas (such as trialling remote meter reading) and less opex on other areas. A prudent and efficient service provider could achieve compliance with existing regulations by redirecting funds from categories of opex which were expected to decline in the forecast access arrangement period. Alternatively it could do this by reprioritising its opex budget. We see no reason why a prudent and efficient service provider would need to seek additional funding from consumers to meet existing regulatory obligations above an efficient base amount of opex.

7.4.3.3 Gas vents on high density polyethylene (HDPE) mains

AGN is proposing opex of \$0.9 million to install 7,900 gas vents covering 274km of high pressure and medium pressure HDPE mains to assist in the detection of gas leaks.⁵² The forecast costs include the utilisation of a two person crew with capacity to visit 20 sites per day and additional APA internal resource costs.⁵³ The project is one of a suite of projects aimed at managing risks associated with the HDPE components of the network.⁵⁴

We do not accept the step change to opex of \$0.9 million for installing gas vents to affected HDPE piping, and have not included this step change in our alternative opex forecast.

⁵⁰ See section 6.4.2.

⁵¹ NGR, r. 91(1).

⁵² Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, p. 119.

⁵³ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, Attachment 7.1, Business Case SA56, July 2015, p. 8.

⁵⁴ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, p. 119.

We note that the proposed step change of \$0.9 million dollars would amount to approximately a quarter of a percent of AGN's total forecast opex for the access arrangement period.

As discussed, while total opex is relatively recurrent, opex on individual projects and programs may not be recurrent. That means each year a service provider could spend more opex on some areas (such as installing gas vents on HDPE mains) and less opex on other areas. We consider AGN acting as a prudent and efficient service provider could allocate the relatively small amount of required funds to this project by redirecting funds from categories of opex which were expected to decline in the forecast access arrangement period. Alternatively it could do this by reprioritising its opex budget. We are not satisfied that a prudent and efficient service provider would need additional funding from consumers for this project above an efficient base amount of opex.

7.4.3.4 Ongoing risk management of HDPE

AGN is proposing opex of \$3.2 million for the provision of additional engineering, pipe sampling and testing resources to mitigate the risks associated with older parts of the HDPE network. The project is aimed at improving public safety and ensuring any risk mitigation activities are consistent with good industry practice and achieve the lowest sustainable cost to consumers.⁵⁵

AGN considers that the project will involve a high level of analysis to ensure that the risks involved are understood and effectively managed. AGN's forecast opex included an additional three FTE engineering resources and provision for further pipe sampling and testing.⁵⁶

We do not accept the step change to opex of \$3.2 million for ongoing risk management of HDPE network components, and have not included this step change in our alternative forecast of total opex.

We recognise that there has been a change in circumstances facing AGN with respect to its HDPE network components. However, based on the information received from AGN, we are not satisfied that AGN has adequately quantified the risks arising from its HDPE network components. As discussed in section 6.4.2, AGN provided little evidence in the form of a rigorous risk assessment to demonstrate that the proposed HDPE projects are prudent or efficient expenses. Any step changes related to HDPE need to be considered holistically as part of AGN's revised risk assessment. We also note that stakeholders have raised concerns about replacing the HDPE piping, rather than continuing the current practice of repair as problems arise.⁵⁷

⁵⁵ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, p. 120.

⁵⁶ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, Attachment 7.1, Business Case SA54, July 2015, pp. 5–6.

⁵⁷ Energy Consumers Coalition of SA, p. 27; SA Government p. 3.

Until we have received further information from AGN appropriately quantifying the risks predicating this step change, we are not satisfied that it should be included in AGN's total opex forecast.

7.4.3.5 Stakeholder education and advocacy

AGN proposed opex of \$1.0 million for a stakeholder engagement program to inform the initiatives described in their access arrangement proposal. The program will include the cost of funding an advisory committee and new initiatives designed in response to stakeholder feedback.⁵⁸

AGN stated the project will be comprised of five components.⁵⁹

- i. Education (development of fact sheets, refreshed website, response to outcomes of ongoing engagement program)
- ii. Transparent (track and report publicly environmental and operation performance, work with stakeholder to test and update Environmental policies and documentation, ensure performance is publicly available and easily accessible)
- iii. Advocate (development of a vulnerable customer strategy and roundtable, working with retailers and consumer advocacy groups)
- iv. Engage (continuation of AGN and retailer reference group, small scale market research, dedicated engagement resources for ad hoc community engagement and to information on forthcoming access arrangement proposals)
- v. Respond (establishment of small customer service team, development of customer strategy and service standards, respond to customer queries and inform community on major works or outages).

AGN has stated that this step change is justified on the basis that it is a response to our Consumer Engagement Guidelines released in November 2013.⁶⁰ It intends to carry out this project across all the jurisdictions in which it operates. AGN's forecast opex for this project across all jurisdictions includes 4.5 FTE, external support for engagement activities and administrative costs. In estimating the cost component attributable to AGN's South Australia network, AGN applied a cost allocation of 36 per cent, commensurate with the proportion of its South Australian customers.

We have not included a step change in opex for consumer engagement costs as part of our alternative opex forecast.

⁵⁸ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, p. 120.

⁵⁹ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, Attachment 7.1, Business Case SA83, July 2015, pp. 3–13.

⁶⁰ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, Attachment 7.1, Business Case SA83, July 2015, pp. 15–17.

We do not consider our consumer engagement guideline is grounds for including a step change. The consumer engagement guideline sets out a framework for service providers to better engage with consumers. It gives service providers a high level framework to integrate consumer engagement into their business-as-usual operations.⁶¹ In other words, the consumer engagement guideline represents the level of consumer engagement we expect a prudent and efficient service provider would be engaged in. For instance, we expect that a prudent service provider to already be engaging closely with relevant consumers as part of its reset process to help understand their preferences around prices, reliability and service standards. We consider base opex should already account for customer interaction, complaint handling and the like, as well as interaction with consumer groups, which was also argued by ECCSA in its submission.⁶²

7.4.3.6 Capex projects reclassified as opex

AGN proposed three capex projects that we consider should be classified as opex. These are:

1. valve corrosion protection (SA09)
2. transmission pressure pipeline corrosion under heat shrink sleeves (SA21a)
3. non-compliant meters inside buildings (SA32).

These projects are targeted at risk reduction rather than extending the life or expanding the capacity of assets. We consider that these projects represent maintenance activity, designed to ensure the ongoing operational effectiveness of the relevant assets. Hence we have assessed the projects against the opex criteria, and the criteria for forecasts and estimates.

Valve corrosion protection (SA09)

This project is a continuation of existing work remediating corroded valves and coating them to protect against further corrosion.⁶³

In undertaking our assessment of this project we examined the business case submitted by AGN. AGN stated the project addresses operational risk associated with corroded valves. It noted feedback from engineering and maintenance inspections that the corrosion has been progressing and periodic maintenance will no longer be effective in stemming the degradation of the valves.⁶⁴ AGN has forecast a total cost associated with the project of \$0.3 million for the 2016–21 period.

⁶¹ AER, *Better Regulation: Consumer engagement guideline for network service providers fact sheet*, November 2013.

⁶² Energy Consumers Coalition of SA, p. 42.

⁶³ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, Attachment 7.1, Business Case SA09, July 2015, pp. 1–7.

⁶⁴ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, Attachment 7.1, Business Case SA09, July 2015, p. 2.

We note the advice of AGN that the program is necessary to manage the operational risk arising from corrosion of valves. However, we consider the costs associated with the program are not material and should be managed from the overall opex program.

We consider AGN acting as a prudent and efficient service provider could allocate the relatively small amount of required funds to this project by redirecting funds from categories of opex which are expected to decline in the forecast access arrangement period. Alternatively it could do this by reprioritising its opex budget. We are not satisfied that a prudent and efficient service provider would need to seek additional funding from consumers for this project above an efficient base amount of opex.

Transmission pressure pipeline corrosion under heat shrink sleeves (SA21a)

This project involves undertaking exploratory excavation to investigate and remediate corrosion on transmission pipelines where heat shrink sleeves have been used, and may have deteriorated.⁶⁵ AGN forecast the total cost of the project to be \$3.4 million, or an annual cost of \$0.7 million in the 2016–21 period.

In undertaking our assessment of this project, we sought input from our engineering consultant (Sleeman Consulting) and examined the business case submitted by AGN. The project has been proposed in response to newly identified risks, arising from corrosion identified in other transmission pipelines where heat shrink sleeves have been used. We consider AGN has provided sufficient information to confirm the project is a reasonable response to address the risks associated with corrosion of the pipeline. We note advice from Sleeman, that the project is physically achievable and estimated costs are also reasonable.⁶⁶ We have adjusted our base year opex by \$672,000 (\$2015–16) to account for the reclassification of this project from capex to opex.

Non-compliant meters inside buildings (SA32)

In undertaking our assessment of this project, we examined the business case submitted by AGN. AGN stated the project involves shifting 726 meters currently located in non-compliant sites (within buildings) to sites that are compliant with the current Australian Gas Distribution Code AS4645.1:2008.⁶⁷ The work is proposed to be carried out over the 2016–21 period at a total cost of \$1.4 million.⁶⁸

AGN also noted the meters in their current locations pose a risk of gas accumulation in an enclosed space, and hence a risk of explosion or fire, with consequent damage to

⁶⁵ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, Attachment 7.1, Business Case SA21a, July 2015.

⁶⁶ Sleeman Consulting, *Review of capex forecasts for selected projects*, report for the Australian Energy Regulator, section 2.3, 18 November 2015.

⁶⁷ AS/NZS 4646.1:2008, *Gas distribution Networks – Network management*. The Standard specifies requirements for safe management of a gas distribution network.

⁶⁸ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, Attachment 7.1, Business Case SA32, July 2015, pp. 1–4.

persons or property. AGN stated that non-compliance has arisen due to past practises and changes made to buildings after the meters were installed.⁶⁹

We consider a prudent and efficient operator should achieve compliance with existing codes regarding safety. We have reviewed the detailed costs provided by AGN and are satisfied the costs meet the opex criteria. We have adjusted our base year opex by \$284,000 (\$2015–16) to account for the reclassification of this project from capex to opex.

7.4.4 Rate of change

Our forecast of total opex includes an allowance to account for efficient changes in opex over time. There are several reasons why forecast opex that complies with the opex criteria might differ from expenditure in the base year.

In the Expenditure Guideline, we developed an opex forecast method incorporating a rate of change in total opex to account for:⁷⁰

- price growth
- output growth
- productivity growth.

Once we have determined the efficient base level of opex in the 2011–16 access arrangement period we apply a forecast annual rate of change to forecast opex for the 2016–21 access arrangement period. The rate of change is forecast as:

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

Where Δ 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 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.

7.4.4.1 Overall rate of change

We have applied a rate of change methodology to derive our alternative estimate of total opex, as set out in our Expenditure Guideline. The methodology we have used is different to that applied by AGN, making direct comparison of overall rate of change difficult. In particular, AGN did not use a rate of change method to account for output growth in its opex model. Overall, we were not satisfied that AGN's rate of change

⁶⁹ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, Attachment 7.1, Business Case SA32, July 2015, pp. 1–4.

⁷⁰ AER, *Better Regulation explanatory statement expenditure forecast assessment guideline*, November 2013, p. 61.

complies with the opex criteria and the criteria for forecasts and estimates. Table 7.3 shows AGN's proposed rate of change and the rate of change applied by the AER.

Table 7.3 AGN proposed and AER draft decision rate of change

	2016–17	2017–18	2018–19	2019–20	2020–21
AGN proposed					
Input prices	0.80	0.91	1.04	1.19	1.88 ^a
Output growth ^b	0.00	0.00	0.00	0.00	0.00
Productivity	0.00	0.00	0.00	0.00	0.00
Total	0.80	0.91	1.04	1.19	1.88
AER draft decision					
Input prices	0.50	0.56	0.64	0.74	1.17
Output growth	-0.01	0.00	0.00	0.00	0.00
Productivity	0.50	0.50	0.50	0.50	0.50
Total	-0.02	0.06	0.14	0.23	0.66

Source: AER analysis. Numbers may not add due to rounding.

Note: a) AGN noted the 2020–21 forecast will be updated when it has access to DAE forecasts for 2020–21.

b) AGN's proposed incremental growth opex is less than 1 per cent of total opex and the derived growth rate is approximately zero (when rounded to two decimal places).

The difference between AGN's proposed rate of change and the rate of change we applied is driven by:

- updated labour price forecasts from DAE
- revised labour and non-labour weightings
- alternative treatment of output growth
- application of productivity growth factor.

AGN's forecasting method differs from ours in that it has accounted for output growth as a specific opex forecast and has not applied an output rate of change to its base opex. AGN has applied an input price rate of change (based on forecast labour costs), but it did not apply a separate productivity factor to its base opex forecast. We have assessed each of the rate of change components separately.

7.4.4.2 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 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 non-labour (materials) price changes.

Labour costs

AGN used an average of labour cost escalators developed by BIS Shrapnel and Deloitte Access Economics to forecast real changes in labour input costs. AGN's proposed labour cost escalators are shown in Table 7.4. Our updated labour cost escalators are in Table 7.5.

Table 7.4 AGN's forecast real labour cost escalators

	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21
BIS Shrapnel	0.90	1.40	1.32	1.47	1.67	1.88
Deloitte Access Economics	0.00	0.20	0.50	0.60	0.70	na
Proposed Labour cost escalation rate	0.45	0.80	0.91	1.04	1.19	1.88*

Source: Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, Opex attachment 7, p. 121.

Note*: AGN advised it did not have access to a forecast for 2020–21 from DAE, but noted it would update its labour cost escalation to reflect new data when it became available.

Table 7.5 AER's forecast real labour cost escalators

	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21
BIS Shrapnel	0.90	1.40	1.32	1.47	1.67	1.88
Deloitte Access Economics	0.00	0.10	0.70	1.0	1.1	1.1
Labour cost escalation rate	0.45	0.75	1.01	1.23	1.39	1.49

Source: AER analysis.

Materials

AGN adopted the approach to materials costs escalation previously used by the AER, that is, no change in materials prices different to the change in the rate of inflation.⁷¹ This is consistent with the method used to develop our alternative total opex forecast. We consider that the CPI represents the best estimate of materials price growth.

⁷¹ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, Opex attachment 7, p. 122.

Labour and materials price weightings

We weight the forecast input price growth to account for the proportion of opex that is labour and non-labour. 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.

AGN has allocated its base year opex costs to categories of labour and non-labour in various ratios depending on the category of expenditure.⁷² We consider that we should not use a service provider's own base year opex price weightings to forecast price change. Doing so would provide the service provider an incentive to use more than the efficient proportion of internal labour in the base year to increase its forecast price change. Consequently we cannot assume an individual service provider's opex price weightings are efficient. Consistent with our recent decision for Jemena Gas Networks we have adopted a 62 per cent weighting for all labour and 38 per cent for non-labour in forecasting input price changes in our alternative opex forecast.⁷³

Our updated input price escalators are set out in Table 7.6.

Table 7.6 AER forecast input price escalators

	2016–17	2017–18	2018–19	2019–20	2020–21
Input prices	0.50	0.56	0.64	0.74	1.17

Source: AER analysis.

7.4.4.3 Output change

Output growth is used to compensate a business for changes in expenditure due to changes in the level of outputs delivered.

AGN accounted for output growth by forecasting the incremental cost of new customer connections. This method uses customer numbers as the sole driver of output growth.

We do not consider AGN's forecast of incremental growth opex adequately accounts for output growth, as it does not account for changes in gas demand (throughput). Changes in gas demand will also impact on total opex. For example, opex includes maintenance expenditure which will vary depending on the size of the network, and expenditure due to gas leakage, which will vary depending on demand. We have included the impact of changes in customer numbers and gas demand to derive an output rate of change. We have incorporated the rate of change due to output growth

⁷² The labour:non-labour ratios applied by AGN are: Operations and maintenance 86:14; Administration and general 64:36; Network development 40:60. Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, Opex Model.

⁷³ AER, Final decision, Jemena Gas Networks (NSW) Ltd, Access arrangement 2015–20, Attachment 7 – Operating expenditure, pp. 17–18.

into our total rate of change that is applied to base year opex. We consider this approach will result in a better forecast of total opex than AGN's incremental growth opex forecast.

To derive our rate of output change measure we reviewed AGN's forecasts for customer numbers and gas demand. We have substituted AGN's gas demand forecast with a revised forecast developed by ACIL Allen Consulting. The ACIL Allen Consulting forecast removes double counting of gas consumption where household type changes.⁷⁴

As we have taken into account both changes in customer numbers and changes in demand, we have had to weight the impact of each of these factors to derive a factor for changes in overall output growth. In constructing our forecast rate of change we adopted the methodology Economic Insights used to prepare Jemena Gas Networks (JGN's) output change, which we accepted. The output weights determined by Economic Insights were:⁷⁵

- throughput (55 per cent)
- customers (45 per cent).

These output weights are based on already established literature and we consider they are appropriate for AGN's output change.⁷⁶

Table 7.7 shows the components of our output growth factor and the factor applied in out alternative total opex forecast.

⁷⁴ ACIL Allen Consulting, *Review of demand forecasts for the AGN South Australian Gas Networks, Report to the AER*, 20 October 2015, p. 18.

⁷⁵ AER, *Draft decision Jemena gas networks access arrangement 2015–20, attachment 7 – operating expenditure*, p. 7–58.

⁷⁶ Economic Insights, *Relative opex efficiency and forecast opex productivity growth of Jemena Gas Networks*, 3 October 2014, p. 17.

Table 7.7 AER draft decision – output growth

	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21
Customer numbers (growth)	429,591 (0.00)	431,061 (0.01)	434,352 (0.01)	439,525 (0.01)	444,920 (0.01)	450,695 (0.01)
Gas throughput (TJ) (growth)	9728,133 (–0.05)	9452,475 (–0.03)	9289,312 (–0.02)	9127,994 (–0.02)	8962,456 (–0.02)	8805,047 (–0.02)
Output growth factor	–0.01	0.00	0.00	0.00	0.00	0.00

Source: Customer numbers and Network length: Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, RIN response; Gas throughput: ACIL Allen Consulting, *Review of demand forecasts for the AGN South Australian Gas Networks*, Report to the AER, 20 October 2015, table 4.10; and AER analysis.

7.4.4.4 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 change to deliver the same level of services. (This is referred to as the “rate of change” and is the “trend” component of the Base–Step–Trend forecasting method). 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 IT.

AGN has not applied a productivity factor to its opex forecast in its proposal. It provided an assessment of its past productivity performance by Economic Insights and used partial productivity measures to benchmark its opex but did not explicitly account for changes in productivity in its forecast opex model. AGN has not supplied forecasts of productivity changes, while other service providers have. ActewAGL Gas Distribution (ActewAGL) in the ACT, and Jemena Gas Networks (JGN) in NSW both provided recent forecasts of improving gas distribution productivity.

We consider the inclusion of forecast productivity change is necessary for us to be satisfied that total forecast opex complies with the opex criteria. If we did not include forecast productivity changes then total forecast opex would be greater than the efficient costs that a prudent operator would require (assuming a positive productivity change). We consider AGN should be able to achieve productivity growth in the 2016–21 period, and not including productivity growth will result in a total opex forecast that does not meet the opex criteria.

Achieving some productivity gains would be consistent with AGN's past experience as well that of other gas distribution businesses and the gas distribution industry as a whole.

AGN has not advised us of any circumstances specific to its network that would result in it being unable to make productivity improvements in the 2016–21 period. Therefore, we expect AGN to obtain productivity gains, as a prudent operator of a gas distribution business. Table 7.8 shows the productivity data we have reviewed to identify an appropriate forecast to apply to AGN.

Table 7.8 Productivity rates of change – gas distribution

	Productivity average annual change (%)
ActewAGL – forecast opex partial productivity growth 2016–21	0.5
JGN – forecast opex partial productivity growth 2015–20	0.59
AGN – forecast opex productivity growth 2016–21	0.0
Gas industry 2006–13	2.12

Source: ActewAGL, *2016–21 Access arrangement information, Productivity study – ActewAGL Gas distribution Network, Final report to JAM on behalf of ActewAGL*, 29 April 2015, p. 40; Jemena Gas Networks, *2015–20 Access arrangement information*, 30 June 2014, p. 31; and Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, July 2015, Attachment 4.1.

In the absence of an AGN-specific forecast we must develop an alternative from the information available to us. We consider AGN could reasonably expect productivity growth in the 2016–21 period. The gas distribution industry has experienced productivity increases since 1999, with higher opex productivity experienced in the year 1999–2006 than between 2006–13. With declining productivity for the gas industry as a whole, we do not consider the historical industry average to be the best forecast to apply to AGN in the 2016–21 period.

However, JGN forecast productivity growth in the relevant period.⁷⁷ Economic Insights noted that AGN’s past productivity growth performance has been comparable to JGN’s in the period 2008–14, and for the longer period 1999–2014.⁷⁸ This adds weight to our view that AGN should obtain some productivity growth in the 2016–21 period, comparable to other gas distribution businesses.

AGN’s zero productivity forecast means that productivity change is not taken into account in its total opex forecast for the 2016–21 period. If productivity growth is accounted for within the other escalation factors applying to the base year forecast,

⁷⁷ Jemena Gas Networks, *2015–20 Access arrangement information*, 30 June 2014, p. 31.

⁷⁸ Economic Insights, *The productivity performance of AGN’s SA gas distribution system, Report prepared for AGN*, 20 May 2015, p. ii.

then there is no need to incorporate a separate productivity factor in the overall rate of change applied to AGN's base year opex. The output growth factor developed for AGN is close to zero in the 2016–21 period, hence we do not expect significant productivity changes to arise from economies of scale. At the same time, the escalation factor we developed for input costs does not take into account productivity changes for labour (the only component subject to real cost escalation). As a result, we consider productivity growth should be separately accounted for in the rate of change applied to AGN's base year opex.

We are aware that differences between service providers can make the forecast productivity measures for ActewAGL and JGN less applicable to AGN. However, other service providers and the industry as a whole appear to be obtaining and forecast to obtain productivity gains. Therefore, we do not consider that the forecast of zero used by AGN results in the best forecast of total opex. In the absence of robust AGN specific forecasts we have applied a productivity growth factor of 0.5 per cent to derive our overall rate of change.

We have selected this productivity forecast based on the forecasts developed by ACIL Allen Consulting for ActewAGL. This is the most up to date productivity forecast for a gas distribution business we have available at this time. We consider this level of productivity growth is achievable by AGN, and have incorporated it into our overall rate of change.

7.4.5 Category specific forecasts

AGN developed specific forecasts for four categories of opex:

- (1) Unaccounted for gas (UAFG): UAFG costs are determined by AGN as the product of forecast UAFG volumes and the price of gas purchased to supply UAFG.
- (2) Network management fee (NMF) paid to APA Group: The fee is set at 3 per cent of revenue and AGN derived its forecast NMF by estimating total revenue and applying the relevant percentage.
- (3) Ancillary reference services (ARS): These are services that are specifically requested by a Network User (for example, a retailer or some large industrial customers) and are forecast on the basis of customer numbers.
- (4) Insurance: AGN engaged an insurance broker to provide a forecast of property and public liability insurance costs. The forecast reflected a real increase in premiums consistent with growth in the regulatory asset base.

We have included AGN's category specific forecast for UAFG in our opex forecast. However, we have not made category specific forecasts for NMF, ARS or insurance. We have included these opex categories in our base year opex that we have escalated using our estimated rate of change. We consider this method results in a better forecast of total opex for AGN.

We make our assessment on total forecast opex and not about particular categories or projects within the opex forecast. Within total opex we expect to see variation in the composition of expenditure from year to year. That is, expenditure for some categories

will be higher than usual in a given year while other categories will be lower than usual. However, these variations tend to offset each other so that total opex is relatively stable.

Using a category specific forecasting method for some opex categories may produce better forecasts of expenditure for those categories but it may not produce a better forecast of total opex. If we apply a revealed expenditure forecasting method at the category level, forecast opex for those categories where expenditure is high in the base year will be higher than the efficient level of expenditure. Conversely, forecast opex will be lower than the efficient level for those categories where expenditure is low or even zero in the base year. Unless we identify every category of expenditure that is higher or lower than the efficient level, applying a base–step–trend forecasting approach to total revealed costs produces a better total opex forecast.

We have included all NMF and ARS expenditure identified by AGN in our estimate of base year costs, and note these expenditures have been subject to the efficiency carryover mechanism in the 2011–16 period. As such, including expenditure for these specific categories of opex in the base year should not detract from the overall efficiency of total opex in the base year.

We note that insurance costs were excluded from the operation of the efficiency carryover mechanism in the 2011–16 period. Therefore, we do not have the benefit of this amount being subject to the same efficiency incentive as other expenditure amounts. However the estimated insurance expenditure for 2014–15 is slightly less than the average for the years 2011–12 to 2014–15, and at less than \$0.5 million, is not significant enough to impact on the overall efficiency of base year opex. The full amount reported for 2014–15 has been reinstated to base year opex in our alternative total opex forecast.

We have applied a different approach to forecasting AGN's UAFG costs. A category specific forecast is required for UAFG so we can apply a "true-up" adjustment in the tariff variation mechanism. We consider this is an appropriate way to address the considerable uncertainty around forecast gas prices in the 2016–21 period.

A comparison of AGN's forecast and our draft decision on category specific forecasts is in Table 7.9.

Table 7.9 Category specific opex (\$million, 2015–16)

Category specific opex	AGN proposed opex 2016–21	Draft decision*
Unaccounted for gas	56.1	56.1
Network management fee	33.2	0
Ancillary reference services	11.2	0
Insurance	3.6	0

Source: AER analysis.

Note: This table reports the amount forecast as category specific opex, it does not show the impact of including NMF, ARS and insurance in the revised base year opex.

Unaccounted for gas

Unaccounted for gas (UAFG) is the difference between the volume of gas that enters a distribution pipeline and the volume of gas billed to customers.⁷⁹ UAFG costs are determined by AGN as the product of forecast UAFG volumes and the price of gas purchased to supply UAFG. AGN forecast UAFG costs of \$56 million (\$2015–16) in the 2016–21 period, around 16 per cent of total opex.

AGN advised that it is participating in a review of the arrangements for the treatment of UAFG, which is considering transferring the responsibility for supplying UAFG from AGN to retailers and self-contracting users. If such an arrangement is implemented AGN's responsibility for purchasing UAFG costs will end.

In our review of the UAFG forecast we have considered how to treat the potential change in UAFG arrangements, as well as the forecast amount.

The review of UAFG arrangements is being managed by AEMO, and AGN advised that if the proposal is implemented it is likely to commence on 1 July 2017 – one year into the 2016–21 period. We note the access arrangement proposed by AGN includes provisions for cost pass through in certain circumstances. A cost pass through allows for tariffs to be adjusted to reflect a change in costs facing AGN. A pass through may be positive or negative. One of the pass through triggers is a regulatory change event, defined as:⁸⁰

A change in a regulatory obligation or requirement that:

(a) falls within no other category of pass through event; and

⁷⁹ ESCV, *Gas distribution system code, Review of UAFG benchmarks*, draft decision, March 2013, p. 8.

⁸⁰ For our draft decision on cost pass through events, see attachment 11 to this draft decision (Reference tariff variation mechanism).

- (b) occurs during the course of an access arrangement period; and
- (c) substantially affects the manner in which AGN provides the Reference Service; and
- (d) materially increases or materially decreases the costs of providing those services.

The removal of the obligation on AGN to supply UAFG would meet the definition of a regulatory change event, and we consider the opex impact of implementation of revised UAFG procedures can be managed through the pass through arrangements in AGN's access arrangements for the 2016–21 period.

There are two components to AGN's forecast UAFG expenditure – UAFG volume and UAFG price. In the 2011–16 period, UAFG was subject to the efficiency carryover mechanism, providing AGN with an incentive to reduce both the volume of UAFG and price it is required to pay. AGN reported UAFG volumes fell by 34 per cent and attribute this to the mains replacement program undertaken in the 2011–16 period.⁸¹ AGN proposed a continuation of the mains replacement program, which we discuss in section 6.4.2, and therefore forecast a continued decline UAFG volumes throughout the 2016–21 period. AGN also noted increasing gas prices will offset the likely savings to consumers arising from falling volumes.⁸² AGN relied on forecast wholesale gas prices from Core Energy to develop its UAFG expenditure forecast.⁸³

We note there is considerable uncertainty around AGN's UAFG expenditure forecast, arising from possible forecasting error impacting UAFG volumes and gas prices. In other jurisdictions we have dealt with the uncertainty around UAFG forecasting through a true-up adjustment in the tariff variation mechanism. For example, if actual market volumes or the cost of purchasing UAG differs from the approved forecast, JGN and its customers are compensated through the tariff variation mechanism.⁸⁴ A similar arrangement has been proposed for ActewAGL gas distribution.⁸⁵ The true-up adjustment means that if prices or volumes rise above forecast, tariffs are adjusted to compensate the service provider for the higher than forecast costs; but if prices or volumes fall tariffs are reduced to compensate the customers for overpayment.

We consider there is considerable merit in applying a similar true-up adjustment to AGN's UAFG expenditure forecast. It reduces the exposure of AGN and its customers to windfall gains or losses arising from significant variations in gas prices. At the same

⁸¹ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, Attachment 7.3, July 2015, p. 4.

⁸² Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, Attachment 7, July 2015, p. 116.

⁸³ Australian Gas Networks, *Access Arrangement Information for Australian Gas Networks South Australian Natural Gas Distribution Network*, Attachment 14.1, July 2015.

⁸⁴ JGN, *Access arrangement 2015–20, AER final decision revisions, Schedule 3*, June 2015, pp. 17–18.

⁸⁵ ActewAGL, *Access arrangement for the ACT, Queanbeyan and Palerang gas distribution network*, 1 July 2016 – 30 June 2021.p. 21.

time the true-up adjustment can still provide incentives on AGN to reduce the UAFG volumes. In JGN's case a specific UAFG benchmark has been applied, and the true-up adjustment takes into account variations between forecast and actual volumes and prices. For AGN we propose to restrict the true-up adjustment to only address price variations, thereby exposing AGN to the cost impact of changes in UAFG volumes.⁸⁶ The specific true-up adjustment in the tariff variation mechanism is discussed in attachment 11.

In our alternative total opex forecast we have maintained a category specific forecast to UAFG expenditure, so that we can apply a true-up adjustment in the tariff variation mechanism to address the considerable uncertainty around future gas prices. As a consequence, the UAFG expenditure will not be subject to the efficiency carryover mechanism applying to AGN.⁸⁷

7.5 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 2015–16 and the 2016–21 period, as set out Table 7.1.

⁸⁶ The volume forecast applied in this draft decision has not been updated to reflect changes in demand forecasts or capital expenditure programs. We expect AGN to provide an updated UAFG forecast at the time of its revised proposal.

⁸⁷ The ECM applies to expenditure forecast using a revealed cost approach. See attachment 9 for a discussion on this issue.