FINAL DECISION
Australian Gas Networks
Access Arrangement
2016 to 2021

Overview

May 2016

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Note

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

The final decision includes the following documents:

Overview

Attachment 1 - Services covered by the access arrangement

Attachment 2 - Capital base

Attachment 3 - Rate of return

Attachment 4 - Value of imputation credits

Attachment 5 - Regulatory depreciation

Attachment 6 - Capital expenditure

Attachment 7 - Operating expenditure

Attachment 8 - Corporate income tax

Attachment 9 - Efficiency carryover mechanism

Attachment 10 - Reference tariff setting

Attachment 11 - Reference tariff variation mechanism

Attachment 12 - Non-tariff components

Attachment 13 - Demand

Attachment 14 - Other incentive schemes

Contents

Shortened forms

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

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

1 Introduction

We, the Australian Energy Regulator (AER), are responsible for the economic regulation of covered gas pipelines[1] in all states and territories in Australia except for Western Australia.

Australian Gas Networks (AGN) provides distribution services to customers in South Australia via a covered pipeline. As with other covered pipelines, we regulate AGN's reference tariffs for these services, and through these, its revenue.

The National Gas Law (NGL) and National Gas Rules (NGR) provide the regulatory framework governing gas networks. In regulating AGN we are guided by the National Gas Objective (NGO), which is set out in the NGL. The NGO is to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.[2]

AGN submitted an access arrangement revision proposal for its South Australian network on 1 July 2015, for the 2016–21 access arrangement period. Our draft decision, released for consultation on 26 November 2015, did not accept AGN's proposal and specified the nature of amendments required to make the proposal acceptable to us.[3] AGN submitted a revised proposal on 6 January 2016. We received submissions on both the draft decision and revised proposal, all of which are available on our website.[4]

1.1 Structure of overview

This overview provides a summary of our final decision and its individual components. It is structured as follows:

- Section 2 provides a high-level summary of our final decision, and highlights where we have made significant changes between our draft and final decisions.
- Section 3 sets out our final decision on AGN's total revenue requirement.
- Section 4 provides a break-down of our revenue decision into its key components.
- Section 5 sets out our final decisions on demand forecasts, AGN's reference service, reference tariff setting and the reference tariff variation mechanism that will

1 Pipeline 'coverage' under the National Gas Law (NGL) determines the level of regulation that applies to a particular pipeline or network. AGN's South Australian distribution network is a covered pipeline. Under section 132 of the NGL, AGN must therefore submit for our approval an access arrangement in respect of the services it provides through the covered pipeline.

2 NGL, s. 23.

3 NGR, r. 59(2).

4 http://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/australian-gas-networks-sa-%E2%80%94-access-arrangement-2016%E2%80%9321/revised-proposal

apply to AGN. It also sets out our final decision on the incentive schemes proposed by AGN for the 2016–21 access arrangement period.

- Section 6 sets out our final decision on non-tariff components of AGN's access arrangement.
- Section 7 explains our views on the regulatory framework and the NGO.
- Section 8 outlines the process we undertook in reaching our final decision.

In our attachments we set out detailed analysis of the individual components that make up our final decision.

2 Final decision

Our final decision is that AGN can recover $985.5 million ($nominal, smoothed) from consumers over the 2016–21 access arrangement period, which begins on 1 July 2016. This is a 19.8 per cent reduction to AGN's revised proposed revenue of $1228.4 million ($nominal). Our final decision allows AGN to recover 5.0 per cent more from its customers than our November 2015 draft decision of $938.6 million ($nominal).

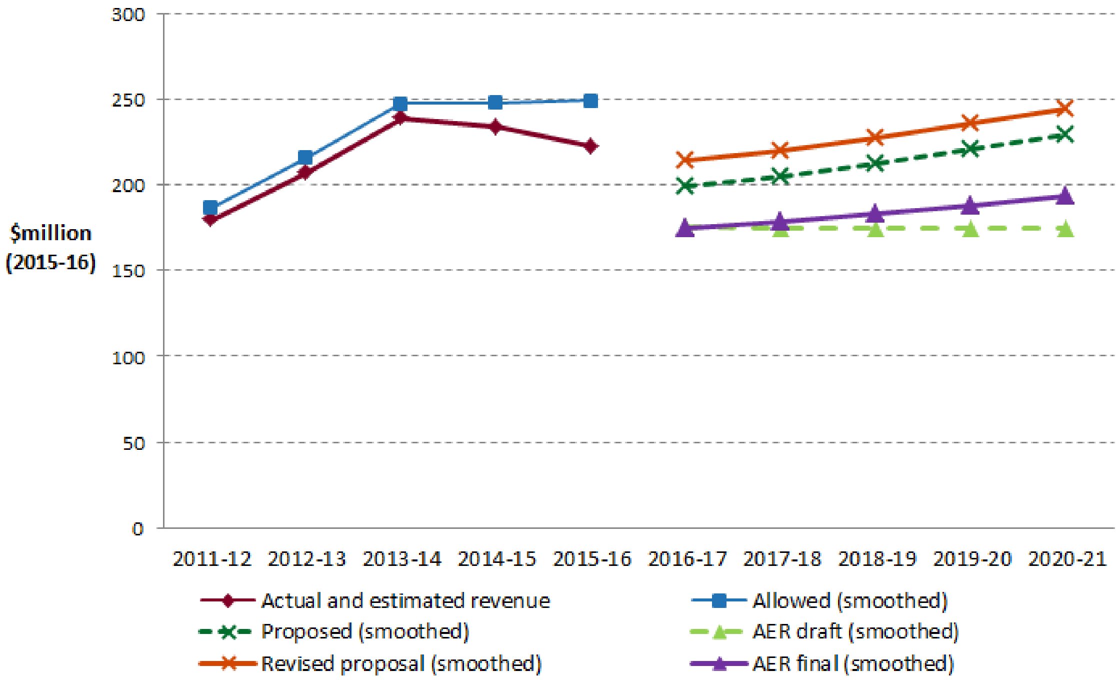
We accept that many aspects of AGN's proposal are consistent with the requirements of the NGR. However, we have not approved all elements, and as such, have not approved AGN's access arrangement proposal as a whole.[5] We have revised AGN's proposed access arrangement having regard to our reasons for refusing to approve some elements of its proposal and the further matters identified in rule 64(2) of the NGR.[6] Our revisions are reflected in the *Approved Access Arrangement for Australian Gas Networks' South Australian distribution network for 2016–21*, which gives effect to this decision.

Figure 1 compares our final decision on AGN's revenue for 2016–21 to its proposed revenue, and to the revenue allowed and recovered during the current access arrangement period.

5 NGR, r. 41(2).

6 Rule 64(2) provides that the AER's proposal for an access arrangement or revisions is to be formulated with regard to (a) the matters the Law requires an access arrangement to include, (b) the service provider's access arrangement proposal, and (c) the AER's reasons for refusing to approve that proposal.

Figure 1 AGN's past total revenue,[a] proposed total revenue and AER final decision ($ million, 2015–16)



Source: AER analysis.

Note: Includes ancillary reference services revenue.

(a) AGN operates under a weighted average tariff cap. This means the tariffs we determine (including the means of varying the tariffs from year to year) are the binding constraint across an access arrangement period, rather than the total revenue requirement set in our decision. Tariffs are derived from the total revenue requirement *after* consideration of demand for each tariff category. Where actual demand varies from the demand forecast in the access arrangement, AGN's actual revenue will vary from the revenue allowance determined in our decision. In general, if actual demand is above forecast demand, AGN's actual revenue will be above forecast revenue, and vice versa.

2.1 What is driving allowed revenue?

Consistent with our draft decision, we approve less revenue for 2016–21 than that allowed—and recovered by—AGN in the current access arrangement period. The total revenue we approve for the 2016–21 access arrangement period is $142.8 million ($ nominal)—or 12.7 per cent—less that we approved in our decision for 2011–16.[7] We also approve 19.8 per cent less revenue than AGN sought to recover through its revised proposal.

Figure 2 compares the average annual building block revenue from our final decision against that proposed by AGN for the 2016–21 access arrangement period, as well as the approved average amount for the 2011–16 access arrangement period.

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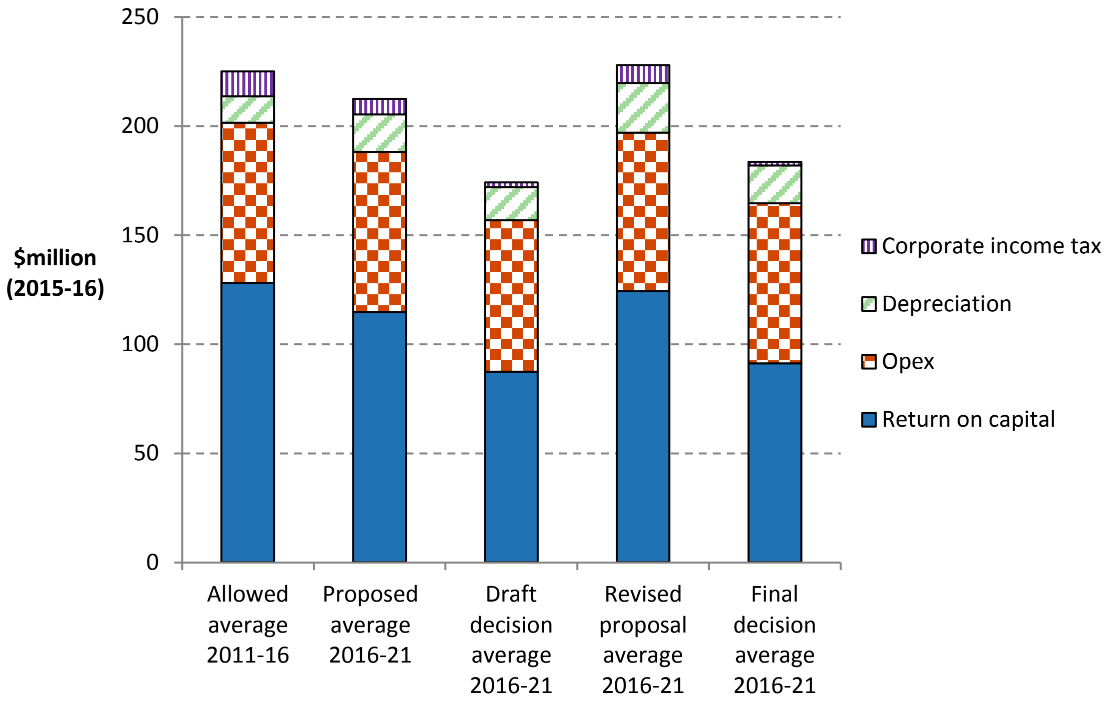
[7] In real terms ($2015–16), total revenue for 2016–21 is $230.0 million or 20.1 per cent less than we approved for 2011–16.

Figure 2 AER's final decision average annual revenue (unsmoothed) compared with AGN's revised proposal average annual revenue for 2016–21 and approved average annual revenue for 2011–16 ($million, 2015–16)

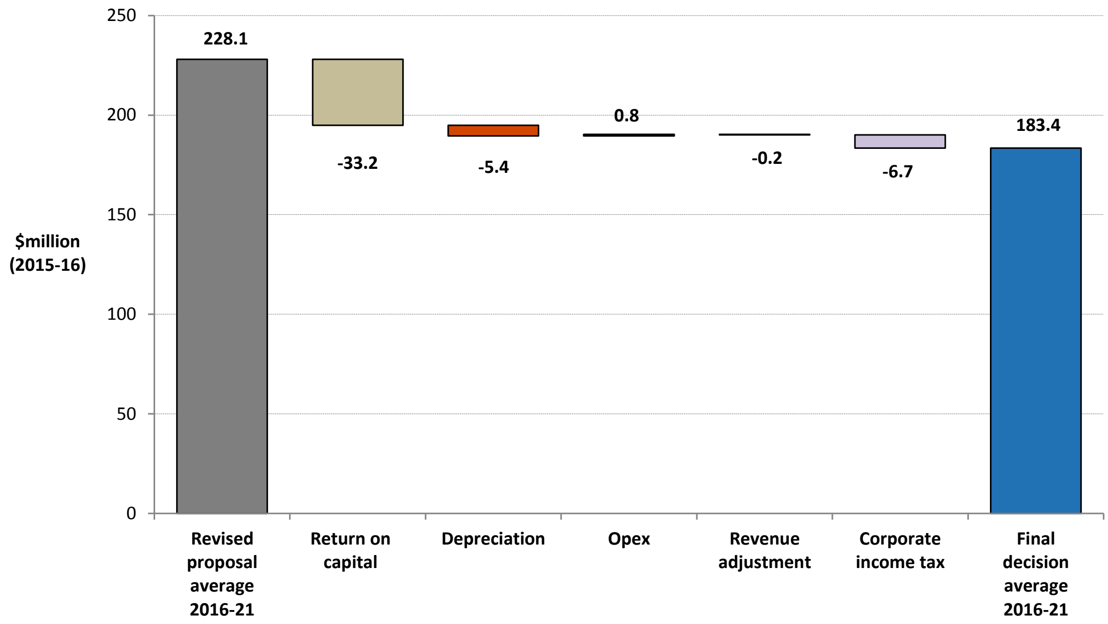


Source: AER analysis.

Note: Includes ancillary reference services revenue.

Figure 3 compares our final decision to AGN's revised proposal, broken down by the various building block components that make up the forecast revenue requirement.

Figure 3 AGN's revised proposal and AER's final decision average annual building block costs ($million, 2015–16)



Source: AER analysis.

Note: Includes ancillary reference services revenue.

These figures highlight that the allowed rate of return—which feeds into the return on capital—is the key difference between our final decision and AGN's revised proposal, and between our decision for the 2016–21 access arrangement period and that for the current 2011–16 period. The allowed rate of return provides AGN with revenue to service the interest on its loans and give a return on equity to its shareholders. It is applied to AGN's capital base to determine the return on capital building block.

Prevailing market conditions for debt and equity heavily influence the rate of return. Financial conditions have changed since our last decision for AGN in July 2011. Interest rates are lower and financial market conditions are more stable. This means that the cost of debt and the returns required to attract equity are lower.

This is reflected in a lower rate of return in this decision. Our final decision is for a rate of return of 6.15 per cent (for 2016–17)[8]—compared to AGN's proposed 8.66 per cent and the 10.28 per cent set for the 2011–16 access arrangement period. While we have considered the information before us in AGN's proposal and in submissions, our approach to the rate of return in this final decision is consistent with that in our draft decision and Rate of Return Guideline.

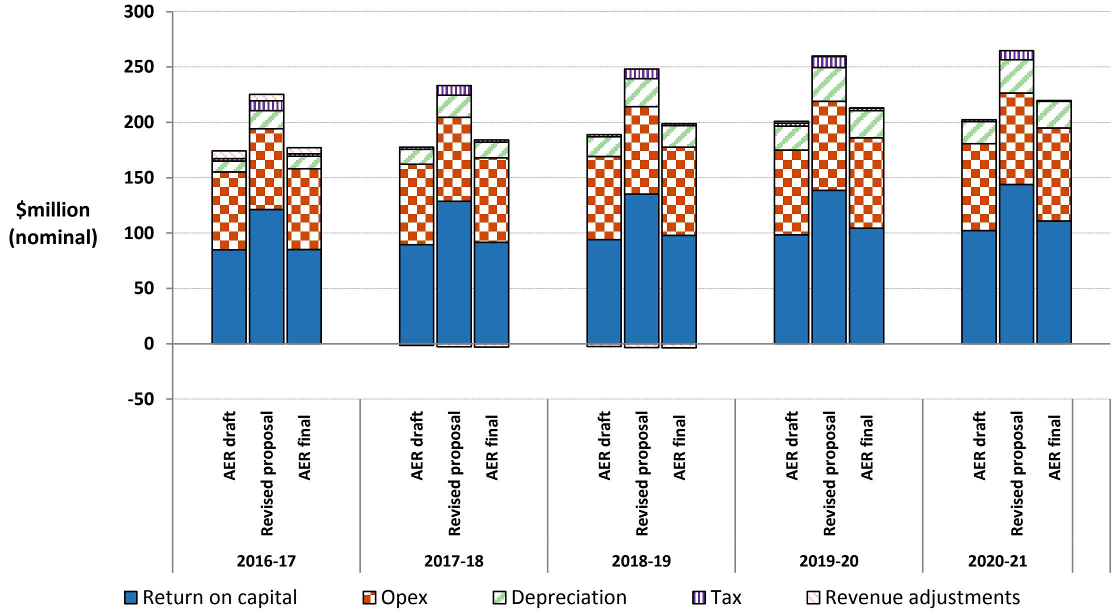
8 For the remaining years of the access arrangement period, we will update the rate of return annually.

2.2 Key differences between our draft and final decisions

While our approved forecast revenue requirement is less than AGN proposed, it is higher than our draft decision.

Figure 4 compares our final decision on each of the revenue building blocks to our draft decision

Figure 4 AER's final decision and AGN's revised proposal building block components of total revenue – unsmoothed ($million, nominal)



Source: AER analysis.

In response to our draft decision we received further information from a number of sources. AGN submitted a revised proposal on 6 January 2016. It also provided further material in a submission on 4 February 2016, and in response to our information requests about its revised proposal. We received submissions from AGN's users and other stakeholders on our draft decision and AGN's revised proposal (listed in Appendix A to this Overview). We have had regard to all of this information in reaching our final decision.

A number of aspects of our decision on AGN's forecast revenue have therefore changed since our draft decision.

In its original proposal, AGN proposed a rate of return of 7.23 per cent, which we did not accept. In its revised proposal, AGN noted the pending decision from the Australian Competition Tribunal relating to the limited merits review process for electricity distributors in NSW and the ACT and for Jemena Gas Networks' gas distribution network in NSW on 26 February 2016. "[T]o cover all possible outcomes from the Tribunal"[9], AGN changed its approach to the calculation of the rate of return and increased its proposed rate of return to 8.66 per cent. The higher rate of return in AGN's revised proposal is largely driven by a change in its approach to estimating the return on debt. AGN previously proposed to calculate its return on debt using a hybrid transition which combines a gradual transition of the base rate to a trailing average and a backwards looking debt risk premium. However, in its revised proposal AGN proposed an immediate transition to a trailing average (using both a backwards looking base rate and debt risk premium). This approach is more favourable to AGN in revenue terms than what it originally proposed.

While our approach to the rate of return has not changed, our final decision updates the rate of return to reflect data from the approved averaging periods for the return on equity and debt. The 6.15 per cent rate of return approved in this final decision is higher than our draft decision of 6.02 per cent (see section 4.2).

Other components of our decision have also changed, including:

- Capital expenditure—our approved total capex forecast of $550.5 million ($2014–15) is 41.4 per cent higher than our draft decision (see section 4.5).
- Operating expenditure—our approved total opex forecast of $363.62 million ($2015–16) is 4.6 per cent higher than our draft decision (see section 4.6).

2.3 Expected impact of decision on gas bills

The distribution charges from our final decision are lower on average over the 2016–21 access arrangement period than what AGN has proposed.

For customers on AGN's South Australian network, distribution charges account for approximately 56 per cent of an annual gas bill.[10] Other factors, such as a customer’s consumption, their choice of retail tariff, and transmission pipeline and wholesale costs, will also affect gas bills. We cannot say with certainty how these factors may change over the 2016–21 access arrangement period.

For illustrative purposes, however, if we hold other components of the bill constant and assume that retailers pass the lower distribution charges that would flow from this final decision through to customers, we estimate that:

- The average annual gas bill for residential customers in South Australia would be expected to reduce by $144 (or 12.4 per cent) in 2016–17 followed by average increases of $36 (or 3.4 per cent) per year over 2017–21 ($nominal). By comparison, had we accepted AGN's revised proposal, the average annual gas bill

[9] AGN, *Revised Access Arrangement Information for AGN's SA Natural Gas Distribution Network*, January 2016, p. I.

[10] AGN, *Reset RIN*, July 2015. The distribution charges account for approximately 57 per cent of the annual gas bill for a residential customer and 55 per cent of the annual gas bill for a small business customer in South Australia.

for residential customers would reduce by $21 (or 1.8 per cent) in 2016–17 followed by average increases of $54 (or 4.4 per cent) per year over 2017–21.[11]

- The average annual gas bill for small business customers in South Australia would be expected to reduce by $750 (or 12.0 per cent) in 2016–17 followed by average increases of $188 (or 3.2 per cent) per year over 2017 –21 ($nominal). Had we accepted AGN's revised proposal, the average annual gas bill for small business customers would reduce by $112 (or 1.8 per cent) in 2016–17 followed by average increases of $283 (or 4.3 per cent) per year over 2017–21.[12]

We discuss the indicative impact of our final decision on annual gas bills further in section 3.1.4 of this overview.

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[11] Our estimate of the potential impact our final decision will have for AGN's residential customers is based on the typical annual gas usage of around 21 GJ per annum for a residential customer in South Australia. See: *ESCOSA, South Australian energy retail offer prices ministerial report 2015*, August 2015, p. 30. Customers with different usage will experience different changes in their bills.

[12] Our estimate of the potential impact our final decision will have for AGN's small business customers is based on the typical annual gas usage of around 190 GJ per annum for a small business customer in South Australia. See: *ESCOSA, South Australian energy retail offer prices ministerial report 2015*, August 2015, p. 30. Customers with different usage will experience different changes in their bills.

3 Total revenue

The total revenue requirement is a forecast of the efficient cost of providing the reference service over the access arrangement period.

AGN operates under a weighted average tariff cap. Its reference tariffs are derived from the total revenue requirement *after* consideration of demand for each tariff category. This means the tariffs we determine (including the means of varying the tariffs from year to year) are the binding constraint across the 2016–21 access arrangement period, rather than the total revenue requirement set in our decision.[13]

3.1.1 The building block approach

We use the building block approach to determine AGN's total revenue requirement—that is, we base the total revenue requirement on our estimate of the efficient costs that AGN is likely to incur in providing the reference service. The building block costs, as shown in Figure 5, include:[14]

- return on the projected capital base (return on capital)
- depreciation of the projected capital base (return of capital)
- the estimated cost of corporate income tax
- revenue increments or decrements resulting from incentive schemes such as the efficiency carryover mechanism
- forecast opex.

Our assessment of capex directly affects the size of the capital base and therefore, the revenue generated from the return on capital and depreciation building blocks.

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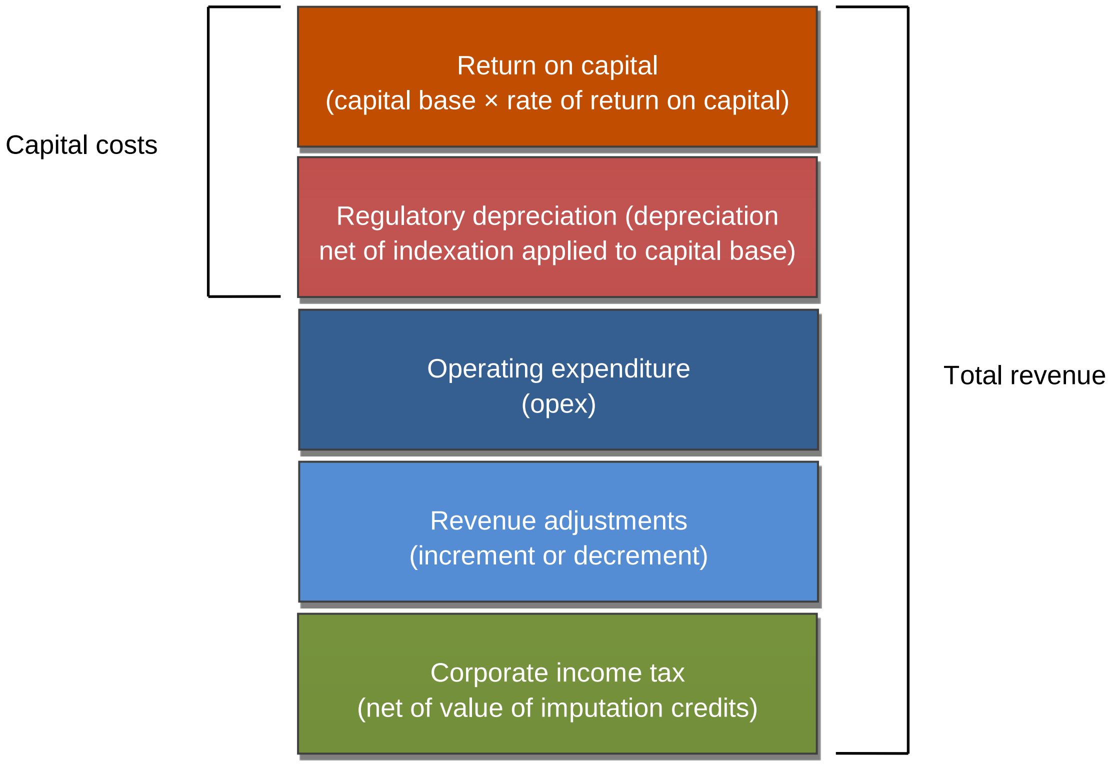
13 Where actual demand across the 2016–21 access arrangement period varies from the demand forecast in the access arrangement, AGN's actual revenue will vary from the revenue allowance determined in our decision. In general, if actual demand is above forecast demand, AGN's actual revenue will be above forecast revenue, and vice versa.

14 NGR, r. 76.

Figure 5 The building block approach for determining total revenue



3.1.2 Final decision on AGN's revenue

We do not approve AGN's revised proposed total revenue requirement (smoothed) of $1228.4 million ($nominal) for reference services over the 2016–21 access arrangement period.[15] Our final decision on the total revenue requirement has been determined using the building block approach set out in rule 76 of the NGR. Based on our assessment of the building block costs, we determine a total revenue requirement (smoothed) of $985.5 million ($nominal) for AGN over the 2016–21 access arrangement period.[16] This total smoothed revenue requirement is $242.9 million (or 19.8 per cent) lower than AGN's revised proposal.

We do not approve AGN's revised proposed 2016–17 tariffs, which would result in a weighted average decrease in real tariffs of 5.47 per cent. We also do not approve AGN’s revised proposed 2017–21 tariff path, which implied a weighted average increase in real tariffs of 5.0 per cent per year.[17] As a result of our lower total revenue requirement, our final decision is for a real decrease in weighted average tariffs of 23.4 per cent in 2016–17, and then real increases of 3.8 per cent for each subsequent year of the 2016–21 access arrangement period.

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15 This amount includes revenues for ancillary reference services.

16 This is calculated by smoothing the unsmoothed building block revenue for the 2016–21 access arrangement period as set in this final decision.

17 AGN, *Revised proposed PTRM*, January 2016.

Table 1 sets out our final decision on AGN's revenue requirement, by building block, for each year of the 2016–21 access arrangement period, the total revenue after equalisation (smoothing) and the X factors for use in the tariff variation mechanism.

Table 1 AER's final decision on AGN's smoothed total revenue and X factors for the 2016–21 access arrangement period ($million, nominal)

Building block	2016–17	2017–18	2018–19	2019–20	2020–21	Total
Return on capital	85.1	91.6	97.9	104.4	111.0	490.2
Regulatory depreciation	11.2	14.3	19.6	24.5	24.0	93.6
Operating expenditure	73.1	76.4	79.7	81.8	83.9	394.9
Revenue adjustments	5.5	–2.8	–3.7	0.3	0.0	–0.7
Corporate income tax	2.2	1.8	1.6	2.2	0.8	8.7
Building block revenue – unsmoothed (including ARS)	**177.2**	**181.4**	**195.2**	**213.2**	**219.8**	**986.7**
Less ancillary reference services revenue	2.2	2.2	2.3	2.4	2.5	11.6
Building block revenue - unsmoothed (excluding ARS)	175.0	179.1	192.9	210.8	217.3	975.1
Building block revenue – smoothed (excluding ARS)	176.3	184.4	193.9	204.1	215.2	973.9
X factor[a]	23.40	–3.80	–3.80	–3.80	–3.80	n/a
Inflation forecast	2.39	2.39	2.39	2.39	2.39	n/a
Nominal price change	–21.6	6.3	6.3	6.3	6.3	n/a
Building block revenue - smoothed (including ARS)	**178.5**	**186.6**	**196.2**	**206.5**	**217.6**	**985.5**

Source: AER analysis.

n/a: not applicable.

(a) Under the CPI–X form of control, a positive X factor is a decrease in price (and therefore in revenue). The X factors are for haulage reference services. The X factor for 2016–17 is indicative only. The final decision establishes 2016–17 tariffs directly, rather than referencing a change from 2015–16 tariffs.

3.1.3 Revenue equalisation (smoothing) and tariffs

Our assessment of AGN's total building block revenue (unsmoothed revenue) yields a lumpy revenue profile. In order to smooth out reference tariffs, we determine a smoothed revenue profile across the 2016–21 access arrangement period. AGN operates under a weighted average tariff cap as its tariff variation mechanism. This means we determine the weighted average tariff change each year such that the net present value (NPV) of unsmoothed and smoothed revenue across the entire period is the same. This weighted average tariff change is labelled the 'X factor'. The mechanics of the tariff variation mechanism are addressed in attachment 11.

Table 2 presents our final decision X factors, and compares them to AGN's revised proposal.

Table 2 Weighted average tariff change across the access arrangement period (X factors) — comparison of AGN's revised proposal and AER's final decision (per cent)

	2016–17	2017–18	2018–19	2019–20	2020–21
Real price change (X factor)					
AGN proposal[a]	11.38	–5.00	–5.00	–5.00	–5.00
AER draft decision	22.80	–0.77	–0.77	–0.77	–0.77
AGN revised proposal	5.47	–5.00	–5.00	–5.00	–5.00
AER final decision	23.40	–3.80	–3.80	–3.80	–3.80
Nominal price change (CPI–X)[b]					
AGN proposal	–9.26	7.51	7.51	7.51	7.51
AER draft decision	–20.95	3.18	3.18	3.18	3.18
AGN revised proposal	–3.21	7.51	7.51	7.51	7.51
AER final decision	–21.57	6.28	6.28	6.28	6.28

Source: AGN, *Access arrangement information*, July 2015, p. 214; AGN, *Revised proposed PTRM*, January 2016; AER analysis.

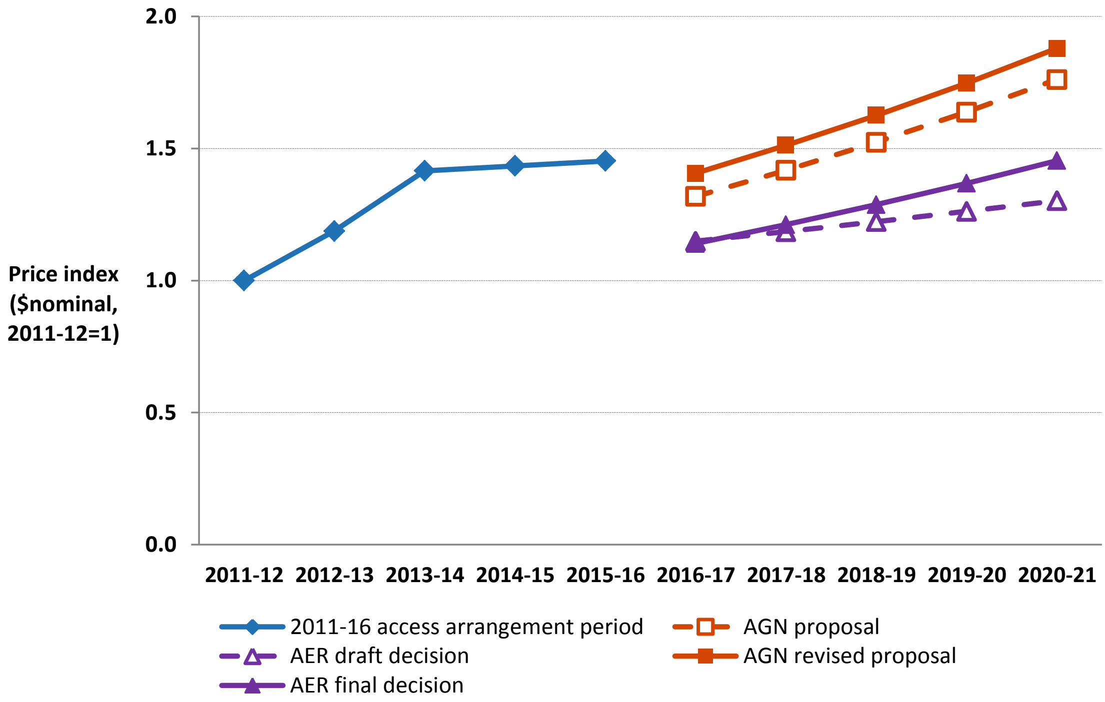
(a) Under the CPI–X form of control, a positive X factor is a decrease in price (and therefore in revenue). For example, an X factor of –5.00 per cent in 2017–18 means a real price increase of 5.00 per cent that year. After consideration of inflation (assumed at 2.39 per cent) this becomes a nominal price increase of 7.51 per cent.

(b) The nominal price changes reflect the final decision forecast inflation of 2.39 per cent per year.

Figure 6 shows indicative tariff paths for AGN's reference services across the 2011–21 period. It compares AGN's proposed tariff path with that approved in the 2011–16 access arrangement, and with this final decision.[18] This provides a broad overall indication of the average movement across this period.

[18] The tariff path for 2011–21 uses actual inflation outcomes for the 2011–15 period, and estimated inflation for 2015–21.

Figure 6 Indicative reference tariff paths for AGN's reference services from 2011 to 2021 (nominal index)



Source: AER analysis; AGN, *Access arrangement information*, July 2015, p. 214; AGN, *Revised proposed PTRM*, January 2016.

The tariff path in AGN's revised proposal was a decrease of 3.21 per cent (in nominal terms) in 2016–17[19], followed by tariffs that increase at 7.51 per cent for each subsequent year of the 2016–21 access arrangement period.[20] Because our final decision provides for lower total smoothed and unsmoothed revenue than AGN's revised proposal, a decrease to the tariff path is required over the 2016–21 access arrangement period to reflect the change in revenue from the 2011–16 access arrangement period. Our final decision tariff path therefore shows a decrease of 21.57 per cent in tariffs (in nominal terms) in 2016–17, followed by an increase of 6.28 per cent for each subsequent year of the 2016–21 access arrangement period.

In determining an appropriate smoothing profile for this final decision we have balanced a number of competing objectives:

- Equalising (in NPV terms) unsmoothed and smoothed revenue
- Providing price signals through reference tariffs that reflect the underlying efficient costs

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19 This reflects AGN's revised proposed X factor of 5.47 per cent for 2016–17 and the final decision forecast inflation of 2.39 per cent.

20 This reflects AGN's revised proposed X factor of –5.00 per cent per year for 2017–21 and the final decision forecast inflation of 2.39 per cent per year.

- Minimising variability in tariffs in 2015–16 and within the 2016–21 access arrangement period
- Minimising the likelihood of variability in tariffs at the start of the 2021–26 access arrangement period.
- Recognising stakeholder preferences for a particular tariff path.

Each of these points is discussed in turn.

First, we are satisfied that our final decision tariff path for AGN's 2016–21 access arrangement period achieves revenue equalisation as required by rule 92(2) of the NGR.[21] As set out above, we have made substantial reductions to the unsmoothed revenue proposed by AGN. Accordingly, we set the tariff path so that it adjusts the smoothed revenue downward to better reflect the unsmoothed building block costs.

Second, but closely related to the first point, our smoothing allows closer alignment of tariffs and costs. This aids the achievement of the NGO and the revenue and pricing principles, including through providing a price signal that facilitates efficient use of natural gas services.[22] Our final decision tariff path shows a large decrease in the first year of the 2016–21 access arrangement period reflecting the lower unsmoothed building block costs.

Third, in setting the tariff path, we aim to minimise tariff volatility in 2015–16 and within the 2016–21 access arrangement period. Our chosen tariff path reflects this objective, but also reflects the consideration we must give to other competing objectives. For instance, setting a flat tariff path from 2015–16 would better minimise within-period volatility, but would not achieve revenue equalisation.

Fourth, in setting the tariff path, we also aim to minimise the likelihood of tariff volatility between this access arrangement period and the next. We do not know what AGN's efficient costs will be in 2021–22, or across the 2021–26 access arrangement period more generally. The unsmoothed building block costs for 2020–21 (the last year of the 2061–21 access arrangement period) are the best available proxy. Hence, this objective requires minimising the divergence between the smoothed and unsmoothed revenues for the last year of the access arrangement period. If there were no significant changes in forecast costs from 2020–21 to 2021–22, this final year divergence gives us an estimate of the size of the tariff change at the start of the 2021–26 access arrangement period. For this final decision, this final year divergence is 1.0 per cent, which is within our usual target of 3 per cent. We note that if there are significant changes in costs at the start of the 2021–26 access arrangement period, this might increase or decrease the required tariff change at that time.

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21 The revenue equalisation occurs in NPV terms, discounting the yearly cash flows at the rate of return to reflect the time value of money.

22 NGL, ss. 23, 24.

Finally, we also considered AGN's preference for the tariff path.[23] AGN noted its preference that the tariff path be aligned with the growth in the forecast capital base over the 2016–21 access arrangement period.[24] We consider that the final decision tariff path largely reflects this preference. We note the average growth in the forecast capital base set in this final decision is about four per cent per year. Our tariff path provides for an initial decrease of 23.40 per cent in 2016–17 and then allows 3.8 per cent increase per year (in real terms) in the last four years of the 2016–21 access arrangement period.

We are satisfied that our final decision tariff path reflects our balanced consideration of these competing objectives.

3.1.4 Indicative impact of distribution charges on annual gas bills

Our final decision on AGN's weighted average tariff cap ultimately affects the prices consumers pay for gas. The weighted average tariff change (X factors) presented above provide the indicative changes (in real terms) in distribution charges.

For customers on AGN's network, distribution charges account for approximately 57 per cent of an annual gas bill for a residential customer and 55 per cent of the annual gas bill for a small business customer in South Australia.[25] We also note that there are other factors, such as transmission pipeline costs, wholesale and retail costs, which affect gas bills.

Our final decision would result in lower distribution charges on average over the 2016–21 access arrangement period compared to AGN's revised proposal as discussed above. However, it is difficult to predict how these other factors may change over the 2016–21 access arrangement period.

For illustrative purposes on the bill impact from our final decision, we have taken the typical annual gas usage of around 21 GJ per annum for a residential customer in South Australia[26], and an average small business customer using approximately 190 GJ of gas per annum.[27]

If we also assume, for the sake of illustration, that all other components of the bill stay the same, and the lower distribution charges from our final decision are passed through to customers, the average annual gas bill for residential customers would be expected to reduce by $144 (or 12.4 per cent) in 2016–17 followed by average increases of $36 (3.4 per cent) per year over 2017–21 ($nominal). By comparison, had we accepted AGN's revised proposal, the average annual gas bill for residential

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23 We did not receive submissions from other stakeholders in relation to the tariff path profile.

24 Email AGN to AER, *AGN Price Path*, 6 April 2016.

25 AGN, *Reset RIN*, July 2015.

26 ESCOSA, *South Australian energy retail offer prices ministerial report 2015*, August 2015, p. 30.

27 AGN, *Reset RIN*, June 2015.

customers would reduce by $21 (or 1.8 per cent) in 2016–17 followed by average increases of $54 (or 4.4 per cent) per year over 2017–21.

Similarly, for an average small business customer in South Australia, our final decision for AGN is expected to lead to lower average annual gas bills. We estimate that if the distribution charges from our final decision are passed through to customers, the average annual gas bill for small business customers would be expected to reduce by $750 (or 12.0 per cent) in 2016–17 followed by average increases of $188 (or 3.2 per cent) per year over 2017–21 ($nominal). Had we accepted AGN's revised proposal, the average annual gas bill for small business customers would reduce by $112 (or 1.8 per cent) in 2016–17 followed by average increases of $283 (or 4.3 per cent) per year over 2017–21.

Table 3 summarises the estimated annual average impacts of our final decision and AGN's revised proposal on the average residential customer and small business customers' annual gas bills, based on the assumptions above.

Table 3 Estimated impact of AGN's revised proposal and the AER's final decision on annual gas bills for the 2016–21 access arrangement period ($nominal)

	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21
AER final decision						
Residential annual gas bill[a]	1166	1022	1055	1090	1127	1167
Annual change		–144 (–12.4%)	33 (3.2%)	35 (3.3%)	37 (3.4%)	40 (3.5%)
Small business annual gas bill[b]	6275	5525	5696	5879	6072	6278
Annual change		–750 (–12.0%)	171 (3.1%)	182 (3.2%)	194 (3.3%)	206 (3.4%)
AGN revised proposal						
Residential annual gas bill[a]	1166	1145	1193	1246	1302	1362
Annual change		–21 (–1.8%)	49 (4.3%)	52 (4.4%)	56 (4.5%)	60 (4.6%)
Small business annual gas bill[b]	6275	6163	6416	6688	6980	7294
Annual change		–112 (–1.8%)	253 (4.1%)	272 (4.2%)	292 (4.4%)	314 (4.5%)

Source: AER analysis.

(a) AER, Energy made easy; 2015–16 annual bill is based on an average annual consumption of 21GJ. ESCOSA, *South Australian energy retail offer prices ministerial report 2015*, August 2015, p. 30; The estimated bill impact reflects the final decision inflation forecast of 2.39 per cent per year.

(b) AER, Energy made easy; 2015–16 annual bill is based on an average annual consumption of 190GJ. ESCOSA, *South Australian energy retail offer prices ministerial report 2015*, August 2015, p. 30; The estimated bill impact reflects the final decision inflation forecast of 2.39 per cent per year.

4 Key elements of decision on AGN's revenue

The components of our decision include the building blocks we use to determine the revenue AGN may recover from its customers.

To determine the overall total revenue requirement of $986.7 million ($nominal, unsmoothed) for the 2016–21 access arrangement period, we:

- apply relevant tests under the NGR, the assessment methods and tools developed as part of our Better Regulation guidelines.[28]
- consider information provided by AGN, the Consumer Challenge Panel (CCP), our consultants and stakeholder submissions.
- consider our overall revenue decision against section 23 of the NGL, including the components of our decision and the interrelationships we discuss in sections 4 and 7.1.1.

The following sections summarises our revenue decision by building block. The attachments provide the detailed explanation of our analysis and findings.

4.1 Capital base

We are required to make a decision on AGN's opening capital base as at 1 July 2016 for the 2016–21 access arrangement period. We are also required to make a decision on AGN's projected capital base for the 2016–21 access arrangement period.

The capital base roll forward accounts for the value of AGN's regulated assets over the access arrangement period. The size of the capital base substantially impacts the service provider's revenue and the price consumers ultimately pay. It is an input into the determination of the return on capital and depreciation (return of capital) building blocks.[29] Other things being equal, a higher capital base increases both the return on capital and depreciation allowances. In turn, those increase the service provider's revenue, and prices for services.

We determine an opening capital base for AGN of $1385.6 million ($nominal) as at 1 July 2016. This is $15.7 million (or 1.1 per cent) lower than AGN's revised proposed value of $1401.3 million. This is because we have updated the capital base roll forward for the 2015–16 actual inflation input and our final decision on conforming capex for 2013–14, 2014–15 and 2015–16 (which were not available at the time of AGN’s revised proposal).

Table 4 summarises our final decision on the roll forward of AGN's capital base over the current 2011–16 access arrangement period.

[28] http://www.aer.gov.au/networks-pipelines/better-regulation.

[29] The size of the capital base also impacts the benchmark debt raising cost allowance. However, this amount is usually relatively small and therefore not a significant determinant of revenues overall.

Table 4 AER's final decision on AGN's capital base roll forward for the 2011–16 access arrangement period ($million, nominal)

	2011–12	2012–13	2013–14	2014–15	2015–16
Opening capital base	1023.9	1070.7	1140.0	1230.8	1303.7
Net capex	58.0	83.9	102.9	106.4	123.4
Indexation of capital base	16.2	26.8	33.4	16.3	17.1
Depreciation	–27.5	–41.4	–45.4	–49.9	–51.9
Closing capital base	1070.7	1140.0	1230.8	1303.7	1392.3
Adjustment for difference between estimated and actual capital expenditure in 2010–11[a]					–6.7
Opening capital base at 1 July 2016					**1385.6**

Source: AER analysis.

(a) Comprising the difference between the actual and estimated capex for 2010–11 and the return on that difference.

We determine a closing capital base of $1901.9 million ($nominal) as at 30 June 2021. This is $78.9 million (or 4.0 per cent) lower than AGN's revised proposal of $1980.8 million. This difference results from our final decisions on other elements of AGN's revised proposal, which have:

- reduced AGN's revised proposed opening capital base as at 1 July 2016 by $15.7 million ($nominal) or 1.1 per cent, as we discussed above
- increased AGN's revised proposed forecast inflation for the 2016–21 access arrangement period from 2.01 per cent per annum to 2.39 per cent per annum
- reduced AGN's revised proposed forecast net capex for the 2016–21 access arrangement period by $92.1 million ($nominal) or 13.1 per cent
- reduced AGN's revised proposed forecast straight-line depreciation for the 2016–21 access arrangement period by $3.0 million ($nominal) or one per cent.

Table 5 sets out the projected roll forward of the capital base during the 2016–21 access arrangement period.

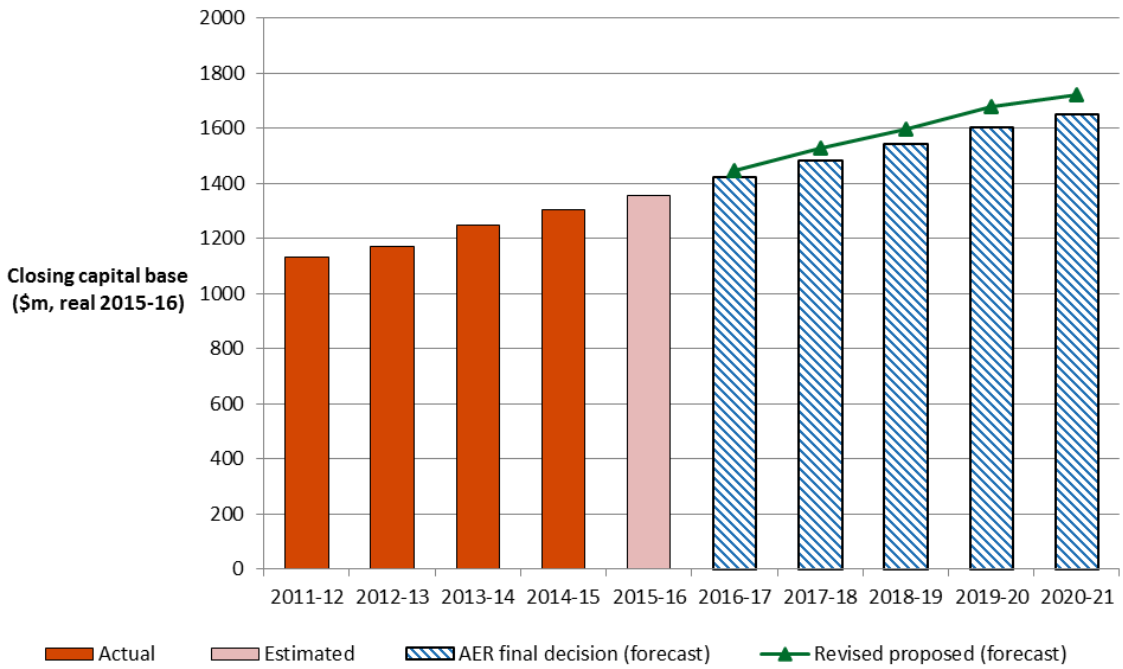
Table 5 AER's final decision on projected capital base roll forward for the 2016–21 access arrangement period ($million, nominal)

	2016–17	2017–18	2018–19	2019–20	2020–21
Opening capital base	1385.6	1491.4	1593.6	1699.2	1807.1
Net capex	116.9	116.6	125.2	132.4	118.8
Indexation of capital base	33.1	35.7	38.1	40.6	43.2
Depreciation	–44.3	–50.0	–57.7	–65.1	–67.2
Closing capital base	1491.4	1593.6	1699.2	1807.1	1901.9

Source: AER analysis.

Figure 7 compares our final decision on AGN's forecast capital base to AGN's revised proposal and actual capital base in real dollar terms.

Figure 7 AGN's actual capital base, revised proposed forecast capital base and AER final decision forecast capital base ($ million, 2015–16)



Source: AER analysis.

4.2 Rate of return (return on capital)

The allowed rate of return provides a service provider a return on capital to service the interest on its loans and give a return on equity to investors. The return on capital building block is calculated as a product of the rate of return and the value of the capital base.

We are satisfied that the allowed rate of return of 6.15 per cent (nominal vanilla) we determined contributes to the NGO and achieves the allowed rate of return objective set out in the NGR.[30] That is, we are satisfied that this allowed rate of return is commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to AGN in providing reference services.[31]

This allowed rate of return will apply to AGN for the 2016–17 regulatory year. A different rate of return will apply to AGN in each remaining regulatory year of the 2016–21 access arrangement period. This is because we will update the return on debt component of the rate of return each year to partially reflect prevailing debt market conditions in each year. We discuss this annual update further below.

In its initial and revised proposals AGN proposed that we depart from the rate of return guideline (the Guideline) and our draft decision on the allowed rate of return for AGN. AGN provided further information in support of its revised proposal, which included a change in methodology for the calculation of return on debt. The Australian Competition Tribunal (the Tribunal) also recently reviewed several of the aspects of our approach to estimating the rate of return that have been contested in our assessment of AGN's proposal. While it upheld a number of these, it found error in other aspects of our approach and remitted these matters back to us. On 24 March 2016, we applied to the Federal Court for judicial review of these aspects of the Tribunal's decision.

With respect to the current decision before us, we have considered the information provided by AGN as well as submissions from other stakeholders on AGN's initial and revised proposals. However, we are not satisfied that a change in our approach would produce an allowed rate of return that better achieves the allowed rate of return objective. Our reasons are highlighted below and explained in further detail in Attachment 3 to this final decision.

We agree with the following aspects of AGN's revised rate of return proposal:

- adopting a weighted average of the return on equity and return on debt (WACC) determined on a nominal vanilla basis (as required by the NGR)
- adopting a 60 per cent gearing ratio
- adopting a 10 year term for the return on debt
- estimating the return on debt by reference to a third party data series
- estimating the risk free rate using nominal Commonwealth government securities averaged over 20 business days as close as practical to the commencement of the access arrangement period
- proposing a benchmark credit rating of BBB+.

[30] NGR, r. 87(2).

[31] NGR, r. 87(3).

However, we are not satisfied that AGN's proposed (indicative) 8.66 per cent rate of return for the 2016–17 regulatory year has been determined such that it achieves the allowed rate of return objective.[32]

Our allowed rate of return is a weighted average of our return on equity and return on debt estimates (WACC) determined on a nominal vanilla basis that is consistent with our estimate of the value of imputation credits.[33] In arriving at our decision we have taken into account the revenue and pricing principles (RPPs) set out in the NGL and are also satisfied that our decision will or is likely to contribute to the achievement of the NGO.[34] Our rate of return and AGN's proposed rate of return are set out in Table 6.

Table 6 Final decision on AGN's rate of return (% nominal)

	Previous access arrangement (2011–16)	AGN revised proposal (2016–17)	AER final decision (2016–17)	Allowed return over 2016–21
Return on equity (nominal post–tax)	10.36	9.76	7.1	Constant (7.1%)
Return on debt (nominal pre–tax)	10.23	7.93	5.51	Updated annually
Gearing	60	60	60	Constant (60%)
Nominal vanilla WACC	10.28	8.66	6.15	Updated annually for return on debt
Forecast inflation	2.55	2.01	2.39	Constant (2.39%)

Source: AER analysis; AGN, *Attachment 10.26, Response to draft decision: Rate of return, 6 January 2016; AGN, Attachment 9.3, Response to draft decision: Inflation*, 6 January 2016; Envestra, *Access Arrangement for Envestra's SA gas distribution system: Amended by order of the Australian Competition Tribunal 10 February 2012*, July 2011.

Our return on equity estimate is 7.1 per cent. Consistent with the Guideline, the return on equity remains constant over the access arrangement period. Our return on equity point estimate and the parameter inputs are set out in Table 7. AGN proposed departing from the approach in the Guideline. We are not satisfied that doing so would result in an outcome that better achieves the allowed rate of return objective.[35] We do not agree with AGN that our method applied in the draft decision will result in a return on equity which is inconsistent with the allowed rate of return objective.[36] Our return on equity draft decision and this final decision is largely consistent with the views in the Guideline.

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[32] AGN, *Attachment 10.26, Response to draft decision: Rate of return*, 6 January 2016, p. 89.

[33] NGR, r. 87(4).

[34] NGL, s. 28.

[35] NGR, r. 87(6)

[36] AGN, *Attachment 10.26, Response to draft decision: Rate of return*, 6 January 2016, pp. 6, 10.

Table 7 Final decision on AGN's return on equity (nominal)

	Previous access arrangement (2011–16)	AGN revised proposal (2016-21)	AER final decision (2016–21)
Nominal risk free rate (return on equity only)	5.56%	2.68%*	2.57%**
Equity risk premium	4.8%	7.16%	4.55%
MRP	6.00%	7.89%	6.50%
Equity beta	0.8	0.91	0.7
Nominal post–tax return on equity	10.36%	9.84%[(a)]	7.1%

Source: AER analysis; AGN, *Attachment 10.26, Response to draft decision: Rate of return*, 6 January 2016; Envestra, *Access Arrangement for Envestra's SA gas distribution system: Amended by order of the Australian Competition Tribunal 10 February 2012*, July 2011.

* Calculated with a placeholder averaging period of 20 business days to 31 October 2015.

** Calculated with an averaging period of 20 business days to 24 March agreed upon in advance of its commencement.

Our return on debt estimate for the 2016–17 regulatory year is 5.51 per cent. This estimate will change each year as we partially update the return on debt to reflect prevailing interest rates over AGN's debt averaging period in each year. Our return on debt estimate for future regulatory years will be determined in accordance with the methodology and formulae we have specified in this decision. As a result of updating the return on debt each year, the overall rate of return and consequently AGN's revenue will also be updated.

Consistent with our draft decision, we agree there should be a transition from the on-the-day approach to the trailing averaging approach. However, we disagree with the hybrid form of transition proposed in AGN's (initial) access arrangement proposal. In its revised proposal, AGN departed from its initial position to apply a transition to the trailing averaging approach. It now proposes to not apply a transition (that is, to immediately move to a trailing average approach). We also disagree with AGN on this approach.

Consistent with our draft decision, we apply a transition to both the base rate and debt risk premium components of the return on debt as per the Guideline.

Our final decision on the return on debt approach is to:

- estimate an on-the-day rate (that is, based on prevailing market conditions) in the first regulatory year (2016–17) of the 2016–21 access arrangement period, and

- gradually transition this rate into a trailing average approach (that is, a moving historical average) over 10 years.[37]

4.3 Value of imputation credits (gamma)

Under the Australian imputation tax system, investors can receive an imputation credit for income tax paid at the company level.[38] These are received after company income tax is paid, but before personal income tax is paid. For eligible investors, this credit offsets their Australian income tax liabilities. If the amount of imputation credits received exceeds an investor's tax liability, that investor can receive a cash refund for the balance. Imputation credits are therefore valuable to investors and are a benefit to investors in addition to any cash dividend or capital gains they receive from owning shares.

However, the estimation of the return on equity does not take imputation credits into account.[39] Therefore, an adjustment for the value of imputation credits is required. This adjustment could take the form of a decrease in the estimated return on equity itself. An alternative but equivalent form of adjustment, which is employed under the NGR, is via the revenue granted to a service provider to cover its expected tax liability. Specifically, the NGR require that the estimated cost of corporate income tax be determined in accordance with a formula that reduces the estimated cost of corporate tax by the 'value of imputation credits' (represented by the Greek letter, γ, 'gamma').[40] This form of adjustment recognises that it is the payment of corporate tax which is the source of the imputation credit return to investors.

We adopt a value of imputation credits of 0.4 for this decision, based on our conceptual approach and a wide range of relevant evidence. Estimating the value of imputation credits is a complex and imprecise task, and as such, requires the use of regulatory judgement. There is no consensus among experts on the appropriate value or estimation techniques to use. Conceptually, the value of imputation credits must be between 0 and 1, and the range of expert views on the value of imputation credits is almost this wide.

We do not accept AGN's proposed value of imputation credits of 0.25.[41] We assessed its reasoning in its revised proposal, and respond in detail in Attachment 4. After AGN

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[37] This final decision determines the return on debt methodology for the 2016–21 access arrangement period. This period covers the first five years of the 10 year transition period. This decision also sets out our intended return on debt methodology for the remaining five years. However, we do not have the power to determine in this decision the return on debt methodology for those years. Under the NGR, the return on debt methodology must be determined in future decisions that relate to that period.

[38] *Income Tax Assessment Act 1997*, parts 3–6.

[39] While the return on equity is not reduced to take into account the value of imputation credits, we note our estimate of the MRP does consider the value we use for imputation credits to ensure it reflects the value to investors in the domestic Australian market inclusive of credits.

[40] NGR, rr. 76(c), 87A.

[41] AGN, *Revised access arrangement proposal: Attachment 11.10—Response to draft decision: Cost of tax*, January 2016, pp. 4–24.

submitted its revised proposal, a number of service providers made late submissions.[42] These late submissions asked us to take into account a range of issues identified in the recent Australian Competition Tribunal (the Tribunal) decisions for ActewAGL Distribution, Ausgrid, Endeavour Energy, Essential Energy and Jemena Gas Networks.[43] We have considered these submissions as fully as possible in the limited time permitted, and we set out our response in Attachment 4. We also sought expert advice from Dr Martin Lally (Lally), in response to the issues raised in these submissions.[44]

In light of the above, in coming to a value of imputation credits of 0.4:

- We adopt a conceptual approach consistent with the Officer framework, which we consider best promotes the objectives and requirements of the NGR. We consider this conceptual approach allows for the value of imputation credits to be estimated on a consistent basis with the allowed rate of return and allowed revenues under the post-tax framework in the NGR.[45]
- We use the widely accepted approach of estimating the value of imputation credits as the product of two sub-parameters: the 'distribution rate' and the 'utilisation rate'. We use a wide range of relevant evidence to estimate these parameters, having regard to expert advice on each source of relevant evidence.
- Overall, the evidence suggests a range of estimates for the value of imputation credits might be reasonable. With regard to the merits of the evidence before us, we choose a value of imputation credits of 0.4 from within a range of 0.3 to 0.5.
- Lally's latest advice recommended a value of imputation credits of at least 0.5. This is higher than the estimate of 0.4 we adopt in this decision. We maintain our approach and final estimate because we consider it meets the requirements of the NGR, taking into account the importance of regulatory certainty and predictability.

We elaborate on our reasons for this decision in Attachment 4.

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42 *United Energy, Submission on AER preliminary determination - Submission on gamma*, 26 April 2016; CitiPower/Powercor, *Submission on implications of recent Australian Competition Tribunal Decision*, 18 April 2016; ActewAGL, *Implication of recent Tribunal decisions for final decision and updates to the allowed rate of return and forecast inflation estimate*, 12 May 2016.

43 For example, see Australian Competition Tribunal, *Applications by Public Interest Advocacy Centre Ltd and Ausgrid [2016] ACompT 1*, 26 February 2016, para 1(c).

44 Lally, *Gamma and the ACT Decision*, May 2016.

45 In finance, the consistency principle requires that the definition of the cash flows in the numerator of a net present value (NPV) calculation must match the definition of the discount rate (or rate of return / cost of capital) in the denominator of the calculation (see Peirson, Brown, Easton, Howard, Pinder, *Business Finance*, McGraw-Hill, Ed. 10, 2009, p. 427). By maintaining this consistency principle, we provide a benchmark efficient entity with an ex ante total return (inclusive of the value of imputation credits) commensurate with the efficient financing costs of a benchmark efficient entity

4.4 Regulatory depreciation (return of capital)

Regulatory depreciation is a component of the annual building block revenue requirement.[46] When determining AGN's forecast total revenue requirement, we must decide on the depreciation for the projected capital base (the 'return of capital').[47] Regulatory depreciation is used to model the nominal asset values over the 2016–21 access arrangement period and the depreciation forecast in the total revenue requirement.

A service provider can only recover the capex it has incurred on assets once. The depreciation forecast reflects how quickly the capital base is being recovered and is based on the remaining and standard asset lives used in the depreciation calculation. Higher (or quicker) depreciation leads to higher revenues over the access arrangement period. It also causes the capital base to reduce more quickly (assuming no further capex). This reduces the return on capital building block, although this impact is usually less than that of the increased depreciation forecast.

In coming to a decision on the proposed depreciation schedule, we assess the compliance of the proposed depreciation schedule with the depreciation criteria set out in the NGR.[48] We must also take into account the NGO and the revenue and pricing principles.[49] If a proposed depreciation schedule complies with the NGR, we must approve it.

Our final decision on AGN's regulatory depreciation allowance is $93.6 million ($nominal) over the 2016–21 access arrangement period as set out in Table 8.

Table 8 AER's final decision on AGN's regulatory depreciation allowance for the 2016–21 access arrangement period ($million, nominal)

	2016–17	2017–18	2018–19	2019–20	2020–21	Total
Straight-line depreciation	44.3	50.0	57.7	65.1	67.2	284.3
Less: indexation on capital base	33.1	35.7	38.1	40.6	43.2	190.7
Regulatory depreciation	**11.2**	**14.3**	**19.6**	**24.5**	**24.0**	**93.6**

Source: AER analysis.

Our final decision on AGN's regulatory depreciation allowance is a reduction of $28.9 million ($nominal) or 23.6 per cent to AGN's revised proposal. This reduction results

46 Under our standard approach, the distinction is made between straight-line depreciation and regulatory depreciation. The difference being that regulatory depreciation is the straight-line depreciation minus the indexation adjustment.

47 NGR, r. 76(b).

48 NGR, r. 89.

49 NGL, s. 28; NGR, r. 100(1). The NGO is set out in NGL, s. 23. The revenue and pricing principles are set out in NGL, s. 24.

from our required updates to the revised proposed remaining asset lives as at 1 July 2016 and our final decisions on other components of the revised proposal, as discussed below.

Consistent with our draft decision, we accept AGN's revised proposed standard asset lives for its asset classes. We also accept AGN's proposed weighted average method to calculate the revised remaining asset lives as at 1 July 2016. However, we have updated AGN's remaining asset lives as at 1 July 2016 to reflect the amended capital base roll forward for the 2011–16 access arrangement period.

Our final decisions on other components of AGN's revised proposal have also affected the calculation of the regulatory depreciation, including:

- a reduction to AGN's revised opening capital base as at 1 July 2016 of $15.7 million ($nominal) or 1.1 per cent
- an increase of the forecast inflation rate from 2.01 per cent per annum in AGN's revised proposal to 2.39 per cent per annum
- a reduction to AGN's revised forecast net capex of $92.1 million ($nominal) or 13.1 per cent.

We do not accept AGN's proposal to increase its regulatory depreciation forecast by making a financeability adjustment of two per cent to reduce the amount of the indexation applied to the projected capital base when the Fund from Operations (FFO) to debt credit metric falls below nine per cent. This is because we consider AGN's proposed adjustment will result in a depreciation schedule which would not meet all the depreciation criteria required by the NGR. Specifically, we consider that the proposed adjustment would result in a depreciation schedule that:

- would not lead to tariffs varying, over time, in a way that promotes efficient growth in the market for reference services.[50] This is because AGN's proposed approach would not allow tariffs to vary with changes in variable costs over time. Therefore, we consider the price paths generated under AGN's proposed approach will not lead to efficiency in network utilisation, investment and asset management. This therefore will not promote efficient growth in the market for reference services.
- would not be consistent with the long term interests of consumers with respect to price. This is because AGN's approach will result in price paths which are not cost reflective.
- would not promote the efficient investment in, provision of, or use of pipeline services. The proposed approach focuses on increasing short term cash flows to achieve certain credit metrics regardless of the reduction in costs forecast in the 2016–21 access arrangement period. This means that consumers will potentially have to pay more for reference services than the cost of producing those services for many years until a lower price may be applied sometime in the future. This

[50] NGR, r. 89(1)(a).

would inefficiently discourage demand at a time of falling costs because prices are set above the efficient level. The lower prices in future will encourage excess demand when AGN expects costs to rise again.[51] This may also lead to current consumers subsidising future consumers.

We consider that the uncertainty around future prices and the intergenerational inequity issue created under AGN's approach are not in the long term interests of consumers, having regard to the NGL's revenue and pricing principles (RPPs).

The foundation of the analysis from both of AGN's consultants depends on a comparison of estimated financial metrics against a threshold financial metric they assume for a particular credit rating. Their assumed financial metric thresholds are taken from excerpts within credit opinions by Moody's Investor Service and Standard & Poor's. We consider AGN and its consultants have placed excessive weight on short excerpts from these credit opinions without having regard to their full context and findings. In a separate confidential appendix to this decision, we have summarised and assessed both of these credit opinions in detail. Contrary to AGN's submission, we are satisfied that these credit opinions support our approaches to rate of return and depreciation, and indicate that the regulatory framework has a positive and supportive impact on the creditworthiness of regulated businesses.

Therefore, for this final decision, we have not accepted the proposed adjustment to the indexation of the capital base in calculating AGN's regulatory depreciation for the 2016–21 access arrangement period. Rather, we have applied full CPI indexation annually in rolling forward AGN's capital base and this full indexation amount is subtracted from the amount of the straight-line depreciation in calculating the regulatory depreciation building block as part of setting total revenue.

We consider the depreciation schedule set in this final decision meets the NGR's depreciation criteria and is in the long term interests of consumers, in accordance with the NGO and RPPs.

4.5 Capital expenditure

Capital expenditure (capex) refers to the capital expenses incurred in the provision of network services. The return on and of forecast capex for reference services are two of the building blocks we use to determine a service provider's total revenue requirement.

We must make two decisions regarding AGN’s capex. First, we are required to assess past capex and determine whether it meets the criteria set out in the NGR to be added to the opening capital base.[52] Where capex meets these criteria, it is referred to as "conforming capex".[53] Secondly, we are required to assess AGN’s forecast of required

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[51] AGN, *Revised proposal: Attachment 9.5 2016/17 to 2020/21 access arrangement information response to draft decision—Financeability*, January 2016, p. 4.

[52] NGR, r. 77(2)(b).

[53] NGR, r. 79.

capex for the 2016–21 access arrangement period to determine whether it is conforming capex.

We consider that $389.4 million ($2014–15) of total net capex for the period 2010–15[54] is conforming capex. This is consistent with our draft decision and AGN's revised proposal.[55] This amount will be rolled into AGN's opening capital base at the start of the 2016–21 access arrangement period.

Our final decision approves $550.5 million ($2014–15) total net forecast capex for the 2016–21 access arrangement period. The revised proposal AGN submitted in January sought $633.7 million ($2014–15) total net forecast capex for 2016–21. AGN subsequently provided an updated capex forecast, which reduced the mains replacement component of its capex forecast from $326.0 million to $277.2 million (discussed further below). This reduced its total capex forecast to $581.4m. Our final decision represents a reduction of 5.3 per cent to AGN's updated capex forecast of $581.4 million ($2014–15), or 13.1 per cent from its January revised proposal. It is 41.4 per cent higher than the total capex forecast approved in our draft decision.

Table 9 compares AGN's updated capex forecast to that approved in our final decision.

Table 9 Comparison of AER final decision and AGN's revised forecast capex over the 2016–21 access arrangement period ($million, 2014–15)

Category	Revised Proposal*	Approved	Difference ($millions)	Difference (%)
Mains replacement	277.2	277.2	0.0	0%
Meter replacement	17.1	17.1	0.0	0%
Augmentation	14.6	14.6	0.0	0%
Telemetry	1.1	1.1	0.0	0%
Regulators	11.3	11.0	-0.3	3%
IT	55.4	55.4	0.0	0%
Growth assets	114.1	85.6	-28.5	25%
Other distribution system	21.3	21.3	0.0	0%
Other non-distribution system	5.0	5.0	0.0	0%
Escalation	12.6	11.9	-0.7	5%
Overheads	55.4	53.9	-1.4	3%

54 Capex for 2015–16 will be assessed as part of our next review, when actual data for that year will be available.

55 AGN's revised proposal included capex of $389.7 million for 2010–15. AGN subsequently agreed $0.3 million of this amount should be assessed as opex (see attachment 6).

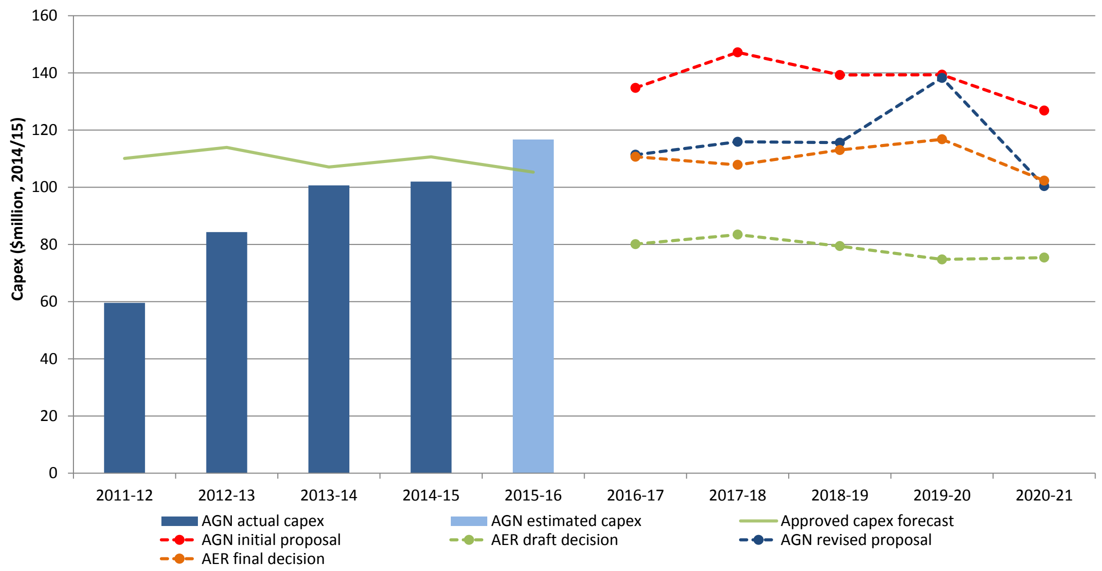
Category	Revised Proposal*	Approved	Difference ($millions)	Difference (%)
GROSS TOTAL CAPITAL EXPENDITURE	**585.0**	**554.0**	**-30.9**	**5%**
Contributions	3.6	3.6	0.0	0%
NET TOTAL CAPITAL EXPENDITURE	**581.4**	**550.5**	**-30.9**	**5%**

Source: AER analysis.

Note: * Proposed capex for each category in this table reflects the updated forecast provided by AGN on 1 March 2016, not the revised proposal submitted on 6 January 2016.

Figure 8 shows the difference between AGN's past and proposed forecast capex, as well as the forecasts we have approved in our previous decision for 2011–16 and this final decision for 2016–21.

Figure 8 AER final decision compared to AGN's past and proposed capex ($million, $2014-15)



Source: AER analysis.

Mains replacement

AGN's distribution mains replacement program involves the replacement of aging cast iron (CI), unprotected steel pipe and high density polyethylene (HDPE) mains.

Our draft decision included $167.7 million ($2014–15, unescalated direct costs) of mains replacement capex in our alternative capex forecast. This was a reduction of 54.7 per cent from AGN's original forecast expenditure of $369.9 million for its mains replacement program. We considered AGN had not provided sufficient evidence to demonstrate that its forecast mains replacement capex was conforming capex over the 2016–21 access arrangement period. Our draft decision provided AGN with direction to submit more compelling evidence in its revised proposal.

We accept AGN's updated forecast of $277.2 million ($2014–15, unescalated) of mains replacement capex (which includes multi-user service inlets) for 2016–21. This element of AGN's capex proposal is a modification to the revised proposal AGN submitted in January 2016. On 1 March 2016, AGN informed us that it had modified its proposal to $277.2 million ($2014–15, unescalated) to replace 1072 kilometres of main pipes.[56] This modified figure of 1072 kilometres of mains replacement reflects the volume approved for the current access arrangement period. AGN's updated forecast of $277.2 million of mains replacement capex is $48.8 million less than its revised proposal of $326.0 million, and $92.7 million less than its initial proposal of $369.9 million.

We consider AGN's proposal to replace 1072 kilometres of mains is sufficiently proximate to our alternative estimate of 985 kilometres of mains replacement to accept. Overall, our estimate supports the conclusion that over the 2016–21 access arrangement period the scale of AGN’s proposal and the associated $277.2 million it has proposed is that which a prudent service provider would incur, acting efficiently. We arrived at our estimate by applying an alternative approach to determine the kilometres of main pipes to replace over the next access arrangement period. This approach is based on observing the historical trend in cracks on pipe mains, where the mains identified for replacement are those that demonstrate deterioration by exhibiting an increasing number of cracks over the current access arrangement period.

In accepting AGN's proposal of 1072 kilometres of mains replacement, our expectation is that AGN will undertake replacement works in the Adelaide central business district (CBD) over the 2016–21 access arrangement period. Our alternative estimate is predicated on AGN undertaking CBD replacement works. AGN has indicated throughout its revised proposal that replacement of CI mains in the CBD is a priority given the risks associated with these pipes.[57] We also note that the South Australian Office of the Technical Regulator regards CBD replacement works as a priority and has for some time. [58]

We also accept AGN's revised unit rates across all categories of mains replacement and AGN's revised proposal of $10 million for its HDPE camera inspection and repair program, which forms part of AGN's wider risk mitigation strategy.

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56 AGN, *Mains Replacement Program alternate proposal to AER*, 1 March 2016, p. 2.

57 AGN, *Revised proposal Attachment 8.10: Response to draft decision - mains replacement program*, January 2016, pp. 23, 28, 29.

58 In the OTR's 2014/15 Gas annual report, the OTR has expressed concerns that AGN has failed to carry over the outstanding block mains replacement in the Adelaide CBD not undertaken in 2012/13 and 2013/14. See: Office of the Technical Regulator, *Annual report of the technical regulator: Gas 2014/15*, 2015, p. 15.

Our reasons for accepting AGN's forecast of mains replacement expenditure, as part of our approved total capex forecast, are set out in Attachment 6 to this final decision.

Growth assets

Our alternative capex estimate includes $85.6 million ($2014–15, unescalated) of growth assets capex, compared to AGN's forecast expenditure of $114.1 million ($2014–15, unescalated) for its growth assets program. This is a reduction of $28.5 million to AGN's forecast expenditure on growth assets.

AGN's revised proposal accepted our draft decision for mains growth, large customers, and both inlets and meters growth assets capex, and we accept this element of its revised proposal ($85.6 million, $2014–15 unescalated).

However, we do not accept AGN's revised proposal for new growth area capex. AGN's revised proposal included $28.5 million for capex in new growth areas in its capex forecast, consisting of:

- $5.0 million to extend its high pressure network by nine kilometres to the Two Wells township north of Adelaide.
- $23.5 million ($2014–15, unescalated) to expand its network 36 kilometres to Mount Barker.

We are not satisfied that the amounts associated with these projects are conforming capex. Capex is conforming (for the purposes of the NGR[59]) if the present value of the expected incremental revenue to be generated as a result of the expenditure exceeds the present value of the capex (NPV analysis).

However, we consider it is unlikely that the expected incremental revenue from these extensions will exceed the present value of the capex, because we find that the penetration rate in these areas is likely to be lower than that assumed in AGN's proposal. AGN has relied on a forecast penetration rate of 95 per cent for both the Two Wells and Mount Barker extensions. Based on the information before us, we are not satisfied that this represents the best forecast or estimate possible in the circumstances. It is our view that the forecast network penetration rate of 65 per cent for new estates represents the best forecast in the circumstances because it better reflects current trends in gas connections. Using this lower penetration rate in the NPV analysis results in the capex being NPV negative.

The reasons for our decision are set out in Attachment 6 to this final decision.

4.6 Operating expenditure

Forecast opex is the forecast of operating, maintenance and other non–capital costs incurred in the provision of reference services.

59 NGR, r. 79(2)(b).

The total opex forecast in AGN's revised proposal was $363.62 million ($2015–16) over the 2016–21 access arrangement period. This is an increase of two per cent from its original proposal.[60] We are satisfied AGN's revised opex proposal complies with the opex criteria and the criteria for forecasts and estimates.[61] We therefore accept the forecast of opex AGN included in its revised proposal. Our final decision on total forecast opex for the 2016–21 access arrangement period is shown in Table 10.

Table 10 Final decision on total opex ($million, 2015-16)

	2016-17	2017-18	2018-19	2019-20	2020-21	Total
AGN's initial proposal	68.39	70.58	72.44	72.64	73.39	357.43
AER draft decision[62]	68.60	69.53	69.95	69.73	69.60	347.40
AGN's revised proposal	70.72	72.10	73.51	73.56	73.73	363.62
AER final decision	70.72	72.10	73.51	73.56	73.73	363.62

Source: AER analysis

Note: Excludes debt raising costs, numbers may not add due to rounding.

In its revised proposal AGN adopted the same forecasting approach as in its initial proposal with some revisions to the inputs:[63]

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

We do not agree with AGN on all the elements of its total opex forecast. For example, while we have adopted AGN's proposed productivity adjustment of zero, we have not adopted all of its proposed step changes. However, when we compare AGN's total

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

61 NGR, rr. 74, 91.

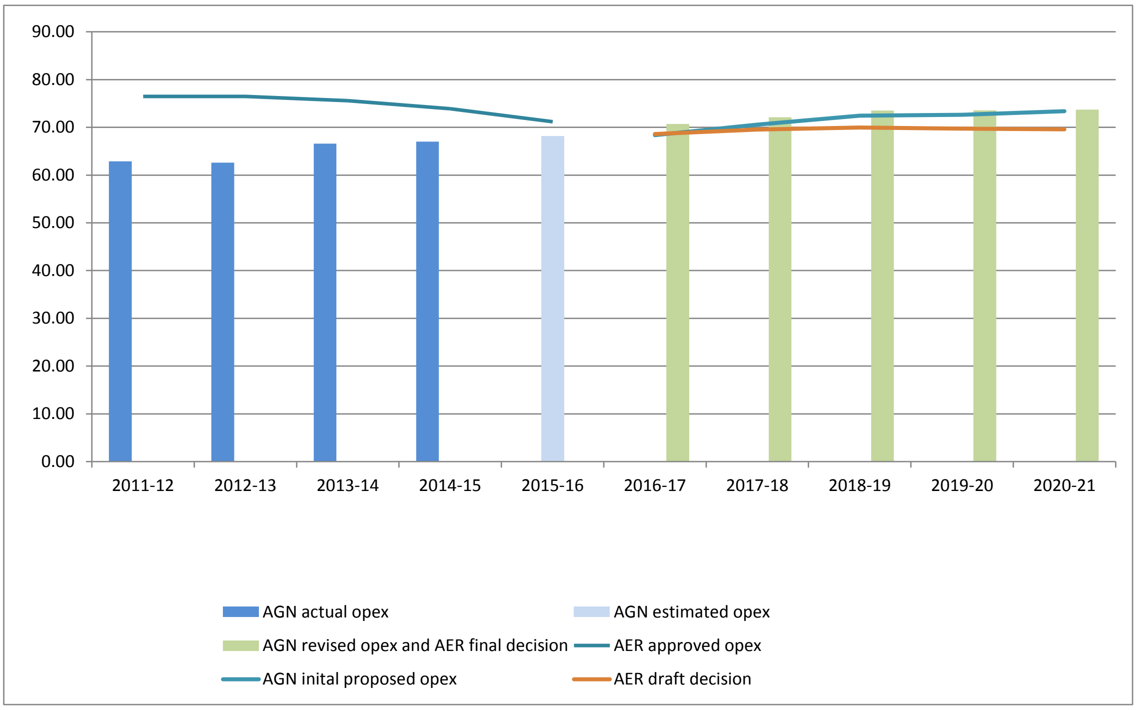
62 After the release of our draft decision we corrected a modelling error which led to an increase in approved opex from $342.35 million to $347.40m. AGN was advised of this error before the submission of its revised proposal.

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

opex forecast with our own estimate of the efficient opex a prudent operator would require, the two are not materially different.

Figure 9 shows our final decision compared to AGN's proposal, as well as its forecast and actual opex in the current period.

Figure 9 Final decision compared to AGN's past and proposed opex ($ million, 2015–16)



Source: AER analysis

4.7 Efficiency carryover mechanism amounts

The opex efficiency carryover mechanism (ECM) provides an additional incentive for service providers to pursue efficiency improvements in opex.

To encourage a service provider to become more efficient during the access arrangement period, it is allowed to keep any difference between its approved forecast and its actual opex during the access arrangement period. This is supplemented with the ECM, which provides the service provider with an additional reward for reductions in opex and additional penalties for increases in opex.

Together, these rewards and penalties work to provide a continuous incentive for a service provider to pursue efficiency gains over the access arrangement period. The ECM also acts to discourage a service provider from inflating its base year opex in order to receive a higher opex allowance in the following access arrangement period.

An ECM applied to AGN during the 2011–16 access arrangement period.

Our final decision is to approve carryover amounts under this mechanism totalling minus $0.5 million ($2015–16) from the 2011–16 access arrangement period. Table 11 shows our final decision on the carryover amounts, which are the same as those proposed by AGN in its revised proposal.[64]

Table 11 AER final decision on carryover amounts ($million, $2015–16)

	2016-17	2017-18	2018-19	2019-20	2020-21	Total
AGN revised proposal	5.4	(2.7)	(3.5)	0.3	0.0	–0.5
AER final decision	5.4	(2.7)	(3.5)	0.3	0.0	–0.5

Source: AER analysis; AGN, *Revised Access Arrangement Information for AGN's SA Natural Gas Distribution Network, Attachment 1.5A South Australian Post tax Revenue Model, ECM spreadsheet*, January 2016.

AGN also proposed an efficiency carryover mechanism continue to apply to it in the 2016–21 access arrangement period. We discuss this in section 5.4.

4.8 Corporate income tax

The NGR require us to make a decision on the estimated cost of corporate income tax for AGN's 2016–21 access arrangement period.[65] The estimated cost of corporate income tax contributes to our determination of the total revenue requirements for AGN over the 2016–21 access arrangement period. It provides for AGN to recover the costs associated with the estimated corporate income tax payable during the period.

Our final decision includes an estimated cost of corporate income tax of $8.7 million ($nominal) for AGN over the 2016–21 access arrangement period as shown in Table 12. This is a reduction of $35.9 million ($nominal) or 80.5 per cent from AGN's revised proposal.

[64] AGN amended its revised efficiency carryover mechanism calculations in February 2016 to reclassify a capex project as opex, refer to AGN, *Response to AER Information request AER AGN 34A Valve Corrosion Protection* [email to AER], 17 February 2016.

[65] NGR, r. 76(c).

Table 12 AER's final decision on corporate income tax allowance for AGN ($million, nominal)

	2016–17	2017–18	2018–19	2019–20	2020–21	Total
Tax payable	3.7	3.0	2.7	3.7	1.4	14.5
Less: value of imputation credits	1.5	1.2	1.1	1.5	0.5	5.8
Net corporate income tax allowance	**2.2**	**1.8**	**1.6**	**2.2**	**0.8**	**8.7**

Source: AER analysis.

Consistent with our draft decision, we accept AGN's proposed approach for calculating the cost of corporate income tax for the 2016–21 access arrangement period. In accepting the approach, however, we have adjusted a number of inputs in AGN's revised proposed PTRM for calculating the cost of corporate income tax. These adjustments, which reflect our final decisions on other elements of AGN's revised proposal, include:

- changing the value of gamma to 0.4 from 0.25
- changes to other building block components including forecast rate of return and forecast capex that impact the forecast cost of corporate income tax.[66]

[66] NGR, r. 87A.

5 Demand, reference tariffs and incentive schemes

5.1 Demand

Demand is an important input to the derivation of AGN's reference tariffs. In simple terms, tariff prices are determined by dividing cost (as reflected in forecast revenue) by total demand (GJ/day), such that an increase in forecast demand has the effect of reducing the tariff price and vice versa. Demand forecasts also affect capex and opex linked to increased network capacity.

Our draft decision identified concerns with the forecasting method that AGN had used to forecast consumption per connection for residential and commercial (or 'volume') customers. We approved alternative demand forecasts to address these concerns and comply with the NGR. AGN's revised proposal incorporates our alternative forecasts, and our final decision accepts these.

5.2 Services covered by the access arrangement

AGN did not propose any changes to the services we approved in our draft decision.[67] The services it will provide over the 2016–21 access arrangement period are:

- the reference services, comprising:
  - haulage reference services
  - ancillary reference services, and
- non-reference services.[68]

Our final decision has not disaggregated meter data services from the haulage reference services as recommended by the Consumer Challenge Panel.[69] The market to implement gas meter reading contestability in South Australia has not changed over the current access arrangement period. We have not been provided with compelling evidence to demonstrate contestability in the market for metering services in South Australia will change over the forthcoming access arrangement period.

We note that price signals are a key element in the development of contestability in services. We consider sufficient price signals will be available over the 2016–21

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67 AER, *Draft decision: Australian Gas Networks access arrangement 2016 to 2021: Attachment 1 — Services covered by the access arrangement*, November 2015, p. 6; AGN*, Revised access arrangement information: Attachment 6.1 – Response to draft decision: Pipeline Services*, January 2016, pp. 1–2.

68 AGN, *Access arrangement information*, July 2015, pp. 103–105.

69 Consumer Challenge Panel, *Advice to AER from Consumer Channel Panel sub-panel 8 regarding the AER draft decision and Australian Gas Networks' (SA) revised access arrangement 2016–2021 proposal*, 23 February 2016, p. 7.

access arrangement period to assist in the development of contestability since AGN's list of ancillary network services contains prices for most metering services it provides.

As noted in our draft decision, we will monitor the market for metering services over the coming years to see whether their disaggregation from the haulage reference services is warranted for future access arrangements.[70]

5.3 Reference tariffs and reference tariff variation mechanism

Service providers are required under the NGR to specify a reference tariff for each reference service.[71] Reference tariffs are updated annually in accordance with the reference tariff variation mechanism.

Our final decision is to apply the structure of reference tariffs proposed by AGN in its original proposal for the 2016–21 access arrangement, which was accepted in our draft decision.[72] Final decision reference tariffs have been amended to reflect our final decision total revenue requirement.

The tariff structure in AGN's revised proposal is consistent with its original proposal but for the addition of new tariffs for the Mount Barker region, which flow from its proposed extension of the network.[73] However, our final decision (discussed in section 4.5, above) is that AGN's forecast capex for the Mount Barker extension is not conforming capex for the 2016–21 access arrangement period. It follows that these tariffs are not required in that period. We otherwise remain satisfied the reference tariff structure initially proposed by AGN and accepted in our draft decision complies with the requirements of the NGR.[74]

In its revised proposal, AGN largely incorporated the revisions our draft decision required to its reference tariff variation mechanism. However, it proposed a change to the adjustment factor formula to accommodate price variations in UAFG. AGN proposed:

- a change in the timing of the true-up of forecast and actual price for UAFG to year t–1 rather than year t–2 as per our draft decision
- the removal of the forecast quantities from the calculation.[75]

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70 AER, *Draft decision: Australian Gas Networks access arrangement 2016 to 2021: Attachment 1 — Services covered by the access arrangement*, November 2015, p. 6.

71 NGR, r. 48(1)(d)(i).

72 AGN, *Access arrangement information*, July 2015, pp. 247–249; AER, *Draft decision: Australian Gas Networks access arrangement 2016 to 2021: Attachment 10–Reference tariff setting*, November 2015, p. 7.

73 AGN*, Revised access arrangement information: Attachment 15.2 – Response to draft decision: Reference tariffs*, January 2016, p. 2.

74 NGR, rr. 93, 94.

75 AGN*, Revised access arrangement information: Attachment 16.1 – Response to draft decision: Tariff variation mechanisms*, January 2016, pp. 3–5.

We do not accept AGN's proposed changes. Our final decision applies the same timing of the true-up of forecast and actual price of year t–2 as in our draft decision. Automatic adjustment factors in other gas distribution networks' reference tariff variation mechanisms all apply a method using year t–2 as the basis. While the outcomes of the two approaches are not materially different, we consider a consistent approach across gas distribution networks and jurisdictions is desirable as it provides regulators, retailers, policy makers and end users greater transparency in the pricing effects of these adjustment factors.[76]

Our final decision also maintains the use of forecast quantities in the method to calculate the adjustment factor to accommodate UAFG price variations for transparency. Our final decision revenue requirement for forecast UAFG is based on both forecast price and forecast quantities. Including the forecast quantities in the method to calculate the true-up provides greater transparency in the annual movement of both price and revenues. Our final decision has updated the UAFG forecast quantities from our draft decision to reflect our final decisions on AGN's mains replacement capex and UAFG forecast.

We also note that our draft decision contained errors in the adjustment factor formula to accommodate price variations in UAFG. Our final decision is to apply an amended version of our draft decision annual reference tariff variation mechanism which corrects these errors.[77]

AGN's revised proposal also largely incorporated our draft decision amendments to its proposed cost pass through events. Our final decision approves all but one of AGN's proposed events. As in our draft decision, we remain of the view that a pass through event for future decisions by AGN to extend its network (which AGN put forward as an alternative to its forecast capex for the Mount Barker extension—see section 4.5 above) is not necessary or appropriate.

5.4 Incentive schemes

A full access arrangement may include (or we may require it to include) one or more incentive mechanisms to encourage efficiency in the provision of services by the service provider. Incentive mechanisms may provide for carrying over increments for efficiency gains, or decrements for efficiency losses, from one access arrangement period into the next.

In the current access arrangement period, AGN was subject to an opex incentive scheme – the ECM. Our final decision on the outcomes of the ECM in the current period is set out in section 4.7 above. AGN has proposed, and we have approved, the continued application of an ECM in the 2016–21 access arrangement period. In its revised proposal, AGN accepted our draft decision to apply an ECM consistent with

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76 NGR, r. 97(3)(d).

77 AER, *Draft decision: Australian Gas Networks Access Arrangement 2016 to 2021, Attachment 11 – Reference tariff variation mechanism*, November 2015, pp. 6, 13–22.

version two of our Efficiency Benefit Sharing Scheme (EBSS) in the 2016–21 access arrangement period.[78] Our final decision approves this element of AGN's revised proposal.

AGN also proposed that we introduce a Capital Expenditure Sharing Scheme (CESS) to its access arrangement. Our draft decision did not accept this element of AGN's proposal. The arguments for the introduction of a CESS in AGN's revised proposal are largely the same as those in its original proposal. However, its revised proposal replaced the CESS AGN originally proposed with the electricity CESS we developed under the NER as part of our Better Regulation program in 2013. AGN argued that "sufficient industry consultation has occurred for the CESS applied in electricity to also apply in gas".[79]

We maintain our decision not to accept AGN’s proposal to implement a CESS in the 2016–21 access arrangement period.

Despite the potential benefits of a CESS, we remain concerned that the addition of a CESS to AGN's access arrangement has the potential to create an overall imbalance in incentives under its access arrangement. This could undermine incentives for efficient investment in AGN's network, and potentially incentivise AGN to reduce capex at the expense of network safety and reliability.[80] Such an outcome would not promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.

AGN's revised proposal reiterated the potential benefits from the application of a CESS it identified in its original proposal. At a high level, AGN submitted that:

- best practice incentive regulation should be focussed on providing the right incentives to reveal efficient outcomes[81]
- the combination of the EBSS and the CESS provide the correct incentives in order for AGN to incur the most efficient form of expenditure (opex or capex)[82]
- the CESS provides the appropriate incentive to continually seek capex efficiencies throughout the access arrangement period, which would otherwise decline over the period.[83]

[78] AGN, *Revised Access Arrangement Information for AGN's SA Natural Gas Distribution Network, Attachment 12.1 Incentive Arrangements*, January 2016, p 2, 9.

[79] AGN, *Revised Access Arrangement Information for AGN's SA Natural Gas Distribution Network, Attachment 12.1 Incentive Arrangements*, January 2016, p. 9.

[80] NGL, s. 24(3), (6).

[81] AGN, *Revised Access Arrangement Information for AGN's SA Natural Gas Distribution Network, Attachment 12.1 Incentive Arrangements*, January 2016, p. 7.

[82] AGN, *Revised Access Arrangement Information for AGN's SA Natural Gas Distribution Network, Attachment 12.1 Incentive Arrangements*, January 2016, p. 9.

[83] AGN, *Revised Access Arrangement Information for AGN's SA Natural Gas Distribution Network, Attachment 12.1 Incentive Arrangements*, January 2016, p. 9.

We recognised these potential benefits in our draft decision. However, our draft decision also set out a number of concerns with AGN’s proposal to add a CESS to its 2016–21 access arrangement that have not been adequately addressed in AGN’s original or revised proposal.

First, there are differences between the capex assessment and forecasting toolkits we use for electricity and gas that were not considered by AGN in its original or revised proposals, or as part of our Better Regulation consultation on the CESS for electricity. The electricity CESS was developed in conjunction with an extensive refinement of our electricity forecasting toolkit as part of the Better Regulation program. In order to ensure a robust and holistic assessment of a possible CESS, we would need to assess both elements of the gas framework together before changes were implemented, rather than considering the CESS in isolation.

Under the NER, the Service Target Performance Incentive Scheme (STPIS) balances the incentives the CESS creates to reduce capex with a financial incentive to maintain or improve on the performance levels funded through the approved forecast revenue requirement. By putting revenue at risk where performance falls below pre-defined targets, the STPIS discourages a business from seeking to maximise benefits from the CESS by reducing capex at the expense of the reliability, safety and security of its network. We find that AGN's proposal for a CESS—while it notes some potential balancing incentives—does not provide for a similar and sufficient counter balance. The absence of an equivalent revenue incentive in AGN's access arrangement is one of the key differences between the electricity and gas frameworks that AGN’s original and revised proposals have not adequately addressed.

We remain of the view that these matters have not been adequately addressed by the information submitted by AGN and others in this review, or through our consultation on a CESS under the NER. Our final decision is not to approve the addition of a CESS to AGN's 2016–21 access arrangement.

6 Non-tariff components

We have accepted all but one element of AGN's revised proposal on the non-tariff components of its access arrangement.

AGN's revised proposal restated without revision its original proposals on queuing requirements and extension and expansion requirements, which we approved in our draft decision. AGN has also made the amendments we required to its review submission date and revision commencement date. Our final decision approves each of these elements of AGN's revised proposal.

Our draft decision also raised concerns regarding AGN's proposal to streamline its capacity trading requirements and the provisions of its access arrangement regarding receipt and delivery point changes. AGN has addressed these concerns in its revised proposal, and our final decision approves the streamlined provisions.

We approve all but one of the non-tariff terms and conditions in AGN's revised access arrangement proposal. AGN proposed that, where it had not met its obligations to users because of failure to access a shared customer's premises, it should not be liable where it had used reasonable endeavours to do so. Under the National Energy Retail Law and Rules, shared customers have an obligation directly to AGN to provide access to premises (under deemed customer connection contracts). AGN can enforce this obligation directly against the shared customer. Where AGN has not done so, we do not accept there is justification to displace the right of users to pursue AGN for failure to perform the agreement because of failure to access premises. Accordingly our approved access arrangement does not include this limitation on AGN's liability.

7 Understanding the NGO

The NGO is the central feature of the regulatory framework. The NGO is

> to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas. [84]

Energy Ministers have provided us with a substantial body of explanatory material that guides our understanding of the NGO.[85] The long term interests of consumers are not delivered by any one of the NGO's factors in isolation, but rather by balancing them in reaching a regulatory decision.[86]

In general, we consider that we will achieve this balance and, therefore, contribute to the achievement of the NGO, where consumers are provided a reasonable level of safe and reliable service that they value at least cost in the long run.[87] We have also considered the quality and reliability of services provided to consumers. For example, the opex allowance and pass through mechanism approved in this final decision have been set so that AGN can meet existing and new regulatory requirements. Our approved capex forecast includes expenditure to replace assets that are aged or in unacceptable condition. It also allows for augmentation and connections capex catering for expected areas of growth, and for upgrades to IT systems to maintain current service levels.

The nature of decisions under the NGR is such that there may be a range of economically efficient decisions, with different implications for the long term interests of consumers.[88] At the same time, however, there are a range of outcomes that are unlikely to advance the NGO, or advance the NGO to the degree that others would.

For example, we do not consider that the NGO would be advanced if allowed revenues encourage overinvestment and result in prices so high that consumers are unwilling or unable to efficiently use the network.[89] This could have significant longer term pricing implications for those consumers who continue to use network services.

Equally, we do not consider the NGO would be advanced if allowed revenues result in prices so low that investors are unwilling to invest as required to adequately maintain

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84 NGL, s. 23.

85 Hansard, *SA House of Assembly*, 9 February 2005, pp. 1451–1460.
Hansard, *SA House of Assembly*, 27 September 2007, pp. 963–972.
Hansard, *SA House of Assembly*, 26 September 2013, pp. 7171–7176.

86 Hansard, *SA House of Assembly*, 26 September 2013, p. 7173.

87 Hansard, *SA House of Assembly*, 9 February 2005, p. 1452.

88 *Re Michael: Ex parte Epic Energy* [2002] WASCA 231 at [143].
Energy Ministers also accept this view – see Hansard, SA House of Assembly, 26 September 2013 p. 7172.
AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18,* p. 50.

89 NGL, s. 24(7).

the appropriate quality and level of service, and where customers are making more use of the network than is sustainable. This could create longer term problems in the network[90] and could have adverse consequences for safety, security and reliability of the network.

The NGL also includes the revenue and pricing principles (RPPs), which support the NGO.[91] As the NGL requires,[92] we have taken the RPPs into account throughout our analysis. The RPPs are:

> A service provider should be provided with a reasonable opportunity to recover at least the efficient costs the service provider incurs in—
>
> - providing reference services; and
> - complying with a regulatory obligation or requirement or making a regulatory payment.
>
> A service provider should be provided with effective incentives in order to promote economic efficiency with respect to reference services the service provider provides. The economic efficiency that should be promoted includes—
>
> - efficient investment in, or in connection with, a pipeline with which the service provider provides reference services; and
> - the efficient provision of pipeline services; and
> - the efficient use of the pipeline.
>
> Regard should be had to the capital base with respect to a pipeline adopted—
>
> - in any previous—
>   - full access arrangement; or
>   - decision of a relevant regulator under section 2 of the Gas Code; or
> - in the Rules.
>
> A reference tariff should allow for a return commensurate with the regulatory and commercial risks involved in providing the reference service to which that tariff relates.
>
> Regard should be had to the economic costs and risks of the potential for under and over investment by a service provider in a pipeline with which the service provider provides pipeline services.

90 NGL, s. 24(6).

91 NGL, s. 24.

92 NGL, s. 28(2).

> Regard should be had to the economic costs and risks of the potential for under and over utilisation of a pipeline with which a service provider provides pipeline services.

Consistent with Energy Ministers' views, we set the amount of revenue that service providers can recover from customers to balance all of the elements of the NGO and consider each of the RPPs.[93] For example:

- In determining forecast opex and capex that reasonably reflects the opex and capex criteria, we take into account the revenue and pricing principle that we should provide AGN with a reasonable opportunity to recover at least efficient costs. (Refer to Attachment 6–capex and Attachment 7–opex).
- We take into account the economic costs and risks of the potential for under and over investment by a service provider in our assessment AGN's forecast capex and opex proposals. (Refer to Attachment 6–capex and Attachment 7–opex).
- We consider the economic costs and risks of the potential for under and over utilisation of AGN's distribution system in our decisions on demand forecasting and forecast augmentation capex (Refer to Attachment 6–capex and Attachment 13–demand).
- Our application of the efficiency carryover mechanism in this decision provides AGN with effective incentives which we consider will promote economic efficiency with respect to the reference service that AGN provides throughout the access arrangement period. (Refer to Attachment 9–efficiency carryover mechanism and Attachment 14–other incentive schemes).
- We have determined AGN's opening capital base taking into account the capital adopted in the previous access arrangement. (Refer to Attachment 2–capital base).
- The allowed rate of return objective reflects the revenue and pricing principle in section 24(5) of the NGL. We have determined a rate of return that we consider will provide AGN with a return commensurate with the regulatory and commercial risks involved in providing pipeline services. (Refer to Attachment 3–rate of return).
- Our financing determinations provide AGN with a reasonable opportunity to recover at least the efficient costs of accessing debt and capital. (Refer to Attachment 3–rate of return).

In some cases, our approach to a particular component (or part thereof) results in an outcome towards the end of the range of options that may be favourable to the businesses, for example, our choice of equity beta. Some of these decisions include:

- selecting at the top of the range for the equity beta
- setting the return on debt by reference to data for a BBB broad band credit rating, when the benchmark is BBB+

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[93] Hansard, *SA House of Assembly*, 27 September 2007 pp. 965, *Hansard, SA House of Assembly*, 9 April 2008 p. 2886, Hansard, SA House of Assembly, 26 September 2013, p. 7173.

- the cash flow timing assumptions in the post-tax revenue model.

We take into account the RPPs when exercising discretion about an appropriate estimate. This requires a recognition that for the long term interests of consumers, the risk of under compensation for, or underinvestment by, a service provider may be less desirable than the risk of overcompensation or overinvestment. However, we are also conscious of the risk of introducing an inherent bias towards higher amounts where estimates throughout the different components of the forecast revenue requirement are each set too conservatively.[94] The legislative framework recognises the complexity of this task by providing us with significant discretion in many aspects of the decision-making process to make judgements on these matters.

Part 9 of the NGR provides specifically for the economic regulation of covered pipelines. It includes detailed rules about the individual components of our decisions. These are intended to contribute to the achievement of the NGO.

7.1 Achieving the NGO to the greatest degree

An access arrangement decision is complex and must be considered as such. In most instances, the provisions of the NGR do not point to a single answer, either for our decision as a whole or in respect of particular components. They require us to exercise our regulatory judgment. For example, Part 9 of the NGR requires us to prepare forecasts, which are predictions about unknown future circumstances. As a result, there will likely always be more than one plausible forecast. There is substantial debate amongst stakeholders about the costs we must forecast, with both sides often supported by expert opinion. As a result, for certain components of our decision there may be several plausible answers or several plausible point estimates.

When the components of our decision are considered together, this means there will almost always be several potential, overall decisions. More than one of these may contribute to the achievement of the NGO. Where this is the case, our role is to make an overall decision that we are satisfied contributes to the achievement of the NGO to the *greatest* degree.[95]

We approach this from a practical perspective, accepting that it is not possible to consider every permutation specifically. Where there are choices to be made among several plausible alternatives each of which would result in an overall decision that contributes to the achievement of the NGO, we have selected what we are satisfied would result in an overall decision that contributes to the achievement of the NGO to the greatest degree.

Also, in coming to this final decision we have considered AGN's proposal. We have examined each of the building block components of the forecast revenue requirement,

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[94] AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18*, 16 November 2016, p. 52.

[95] NGL, s. 28(1)(b)(iii).

and the incentive mechanisms that should apply across the next access arrangement period. We have considered submissions we received in regard to AGN's proposal. We have conducted our own analysis and engaged expert consultants to help us better understand if and how AGN's proposal contributes to the achievement of the NGO. We have also considered how the individual components of our decision relate to each other, the impact that particular components of our decision have on others, and have described these interrelationships in this final decision. We have had regard to and weighed up all of the information assembled before us in making this final decision, and have made as much of this information publicly available as practicable for the purposes of consultation.

Therefore, we are satisfied that among the options before us, our final decision on AGN's access arrangement for the 2016–21 access arrangement period contributes to achieving the NGO to the greatest degree.

7.1.1 Interrelationships between individual components

Considering individual components in isolation ignores the importance of interrelationships between components of the overall decision, and would not contribute to the achievement of the NGO. As outlined by Energy Ministers, considering the elements in isolation has resulted in regulatory failures in the past.[96] Interrelationships can take various forms, including:

- underlying drivers and context which are likely to affect many constituent components of our decision. For example, forecast demand affects forecasts of the efficient levels of capex and opex in the access arrangement period (see attachments 6, 7 and 13).
- direct mathematical links between different components of a decision. For example, the value of imputation credits (gamma) has an impact on the appropriate tax allowance; the benchmark efficient entity's debt to equity ratio has a direct effect on the cost of equity, the cost of debt, and the overall vanilla rate of return (see attachments 3, 4 and 8).
- trade-offs between different components of revenue. For example, undertaking a particular capex project may affect the need for opex and vice versa (see attachments 6 and 7).
- trade-offs between forecast and actual regulatory measures. The reasons for one part of a proposal may have impacts on other parts of a proposal. For example, completion of forecast augmentation (capex) to the network will mean the service provider has more assets to maintain, leading to higher opex requirements (see attachments 6 and 7).

[96] SCER, *Regulation Impact Statement: Limited Merits Review of Decision-Making in the Electricity and Gas Regulatory Frameworks – Decision Paper*, 6 June 2013 p. 6.

- the service provider's approach to managing its network. The service provider's governance arrangements and its approach to risk management will influence most aspects of the proposal, including capex/opex trade-offs (see attachments 6 and 7).

We have considered interrelationships, including those above, in our analysis of the individual components of our decision. These considerations are explored in the relevant attachments.

8 Consultation

Stakeholder participation is important to informed decision making under the NGL and NGR. It allows us to take a range of views into account when considering how a proposal or decision contributes to the NGO. Effective consultation and engagement provide confidence in our processes and are good regulatory practice. This is reflected in the consultation process set out in the NGR, under which we have:

- published AGN's access arrangement revision proposal and the material AGN provided in support of that proposal
- invited and had regard to written submissions on AGN's proposal
- published a draft decision and reasoning
- published AGN's revised proposal and supporting material
- invited and had regard to written submissions on both our draft decision and AGN's revised proposal
- published this final determination and reasoning.

We also sought advice from the AER's Consumer Challenge Panel (CCP) on AGN's original and revised proposals and our draft decision. Both the CCP and AGN met with the AER Board to discuss this review.

Our engagement on this review builds on consultation we undertook as part of the Better Regulation program. Following the 2012 changes to the National Electricity Rules (NER) and NGR, we spent much of 2013 consulting on and refining our assessment methods and approaches to decision making. We referred to this as our Better Regulation program. The Better Regulation program was designed to be an inclusive process that provided an opportunity for all stakeholders to be engaged and provide their input.[97]

This gives us confidence the approaches set out in the Guidelines, which we have applied where appropriate in this decision, will result in decisions that will or are likely to contribute to the achievement of the NGO to the greatest degree. Our Better Regulation guidelines are available on our website and include:[98]

- Expenditure Forecast Assessment Guideline
- Expenditure Incentives Guideline
- Rate of Return Guideline
- Consumer Engagement Guideline for Network Service Providers
- Shared Assets Guideline, and

[97] AER, *Overview of the Better Regulation reform package*, April 2014, pp. 4 and 7–13.

[98] See AER, http://www.aer.gov.au/networks-pipelines/better-regulation.

- Confidentiality Guideline.

We acknowledge that the changes to the NGR were more limited than those made to the NER. The two frameworks still differ, and not all elements of the Better Regulation Guidelines were developed with gas access arrangements under the NGL and NGR in mind. However, many of the concepts and analytical tools are the same and we involved gas service providers in consultation on all aspects of the Better Regulation program.

8.1 AGN's own engagement with consumers

AGN also undertook its own stakeholder engagement in the development of its proposal. Submissions received by us from Business SA, [99] the South Australian Council on Social Service (SACOSS) [100] and the Energy Consumers Council of SA (ECCSA), [101] as well as advice from the CCP recognise that AGN has taken important steps to involving consumers in the regulatory process in the lead up to submission of its original proposal.[102] We supported this view.

AGN's revised proposal substantially changed its position on the return on debt. As the CCP noted in its advice:[103]

> The AGN RAAP proposes a rate of return or Weighted Average Cost of Capital (WACC) of 8.2%. This is a significant departure from the WACC of 7.2% submitted in the AAP which, if implemented, would have a very large impact on consumers. AGN has not provided any justification for this increase, apart from the statement that it is “to cover all possible outcomes from the Tribunal”.
>
> …
>
> It is also of concern that such a major change to AGN’s AAP should be submitted without prior stakeholder engagement, and with only a limited opportunity for stakeholders to respond. This action will likely have the effect of undermining any goodwill that AGN has built up with stakeholders through its earlier Stakeholder Engagement Program.

This change in approach had a substantial impact on AGN's proposed revenue relative to its original proposal. This is an important issue and we would expect such a significant change would have lead AGN to consult with their users and consumers on

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99 Business SA, *Submission to AER on proposed Australian Gas Networks Access Arrangement (2016-21),* 10 August 2015, p. 4.

100 SACOSS, *Submission on AGN’s regulatory proposal for the 2016-2021 Access Arrangement (AA) period*, 8 August 2015.

101 ECCSA, *Australian Energy Regulator SA Gas Distribution Revenue Reset AGN Application response*, 16 August 2015.

102 CCP8, *Advice to AER from Consumer Challenge Panel sub-panel 8 regarding Australian Gas Networks’ (SA) Access Arrangement 2016-2021 Proposal,* 25 August 2015.

103 Consumer Challenge Panel, *Supplementary advice to AER from Consumer Challenge Panel sub-panel 8 - AGN*, 31 March 2016, p. 2.

its change in approach. However, we do not have any evidence to suggest whether and how such engagement took place.

A List of submissions

Submission from	Date received
ActewAGL Distribution	4 February 2016
AGL Energy Limited	5 February 2016
Australian Gas Networks Limited	4 February 2016; 1 March 2016; 9 May 2016
Alternative Technology Association	3 February 2016
Business SA	29 January 2016
Consumer Challenge Panel (sub-panel 8)	31 March 2016
Energy Consumers' Coalition of South Australia	4 February 2016
Government of South Australia	20 November 2015*; 24 February 2016
Mount Barker District Council	9 February 2016
Origin Energy	4 February 2016
SACOSS	4 February 2016
Uniting Care Australia	9 March 2016
Urban Development Institute of Australia	11 March 2016

* The 20 November 2015 submission from the Government of South Australia was not received in time to be considered in our draft decision. It has been considered in this final decision.