DRAFT DECISION
Australian Gas Networks Victoria and Albury gas access arrangement 2018 to 2022

Overview

July 2017

AUSTRALIAN ENERGY REGULATOR

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Invitation for submissions

This is our draft decision on AGN's access arrangement for the period 1 January 2018 to 31 December 2022. AGN will submit a revised proposal in response to this draft decision by 14 August 2017. Interested parties are invited to make submissions on both our draft decision and AGN's revised proposal by 15 September 2017.

We will consider and respond to all submissions received by that date in our final decision.

Submissions should be sent to: VicGAAR2018-22@aer.gov.au.

Alternatively, submissions can be sent to:

Mr Chris Pattas
General Manager
Australian Energy Regulator
GPO Box 520
Melbourne VIC 3001

Submissions should be in Microsoft Word or another text readable document format.

We prefer that all submissions be publicly available to facilitate an informed and transparent consultative process. Submissions will be treated as public documents unless otherwise requested. Parties wishing to submit confidential information should:

(1) clearly identify the information that is the subject of the confidentiality claim

(2) provide a non-confidential version of the submission in a form suitable for publication.

All non-confidential submissions will be placed on our website. For further information regarding our use and disclosure of information provided to us, see the *ACCC/AER Information Policy* (June 2014), which is available on our website.[1]

[1] https://www.aer.gov.au/publications/corporate-documents/accc-and-aer-information-policy-collection-and-disclosure-of-information

Note

This overview forms part of the AER's draft decision on the access arrangement for AGN's Victoria and Albury gas distribution networks for 2018-22. It should be read with all other parts of the draft decision.

The draft decision includes the following documents:

Overview

Attachment 1 - Services covered by the access arrangement

Attachment 2 - Capital base

Attachment 3 - Rate of return

Attachment 4 - Value of imputation credits

Attachment 5 - Regulatory depreciation

Attachment 6 - Capital expenditure

Attachment 7 - Operating expenditure

Attachment 8 - Corporate income tax

Attachment 9 - Efficiency carryover mechanism

Attachment 10 - Reference tariff setting

Attachment 11 - Reference tariff variation mechanism

Attachment 12 - Non-tariff components

Attachment 13 - Demand

Attachment 14 - Other incentive schemes

Contents

Shortened forms

Shortened form	Extended form
AER	Australian Energy Regulator
ATO	Australian Tax Office
capex	capital expenditure
CAPM	capital asset pricing model
CESS	Capital Expenditure Sharing Scheme
CPI	consumer price index
DRP	debt risk premium
ECM	(Opex) Efficiency Carryover Mechanism
ERP	equity risk premium
Expenditure Guideline	Expenditure Forecast Assessment Guideline
gamma	Value of Imputation Credits
MRP	market risk premium
NGL	National Gas Law
NGO	national gas objective
NGR	National Gas Rules
NPV	net present value
opex	operating expenditure
PTRM	post-tax revenue model
RBA	Reserve Bank of Australia
RFM	roll forward model
RIN	regulatory information notice
RPP	revenue and pricing principles
SLCAPM	Sharpe-Lintner capital asset pricing model
STTM	Short Term Trading Market
TAB	Tax asset base
UAFG	Unaccounted for gas
WACC	weighted average cost of capital
WPI	Wage Price Index

1 Introduction

The Australian Energy Regulator (AER) regulates energy markets and networks under national energy market legislation and rules. Our network regulatory functions relate to energy networks in all Australian states and territories, except Western Australia. They include setting the amount of revenue that monopoly network businesses can recover from customers for using networks (electricity poles and wires and gas pipelines) that transport energy.

The National Gas Law and Rules (NGL and NGR) provide the regulatory framework governing gas networks. Our work under this framework is guided by the National Gas Objective (NGO):[2]

> …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.

Australian Gas Networks Limited (AGN) owns and operates gas distribution pipelines servicing customers in Victoria and Albury. Gas pipelines that are subject to full regulation—like AGN's Victoria and Albury networks—are regulated by the AER under an approved access arrangement.[3] An access arrangement specifies certain pipeline services (reference services), and the price and non-price terms and conditions on which those reference services will be offered over the next five years (2018–22). This forms the foundation for negotiations between pipeline operators and users.

To approve an access arrangement, we make regulatory decisions on the revenue that AGN can recover from users of its reference services. For this draft decision, our assessment is based on the proposal AGN submitted for its Victoria and Albury pipelines on 22 December 2016.[4] AGN's proposal sets out its view of its expected costs, demand and required revenues for the period 1 January 2018 to 31 December2022.

This Overview, together with its attachments, constitutes our draft decision on AGN's access arrangement proposal. This draft decision is one of the key steps in reaching our final decision. AGN will have the opportunity to submit a revised proposal in response to this draft decision. Stakeholders will then have the opportunity to make

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2 NGL, s. 23.

3 The NGL provides for different types of regulation to apply to gas pipelines, based on competition and significance criteria. A 'full regulation' pipeline must periodically submit an access arrangement to the AER, setting out pricing for a reference service sought by a significant part of the market (see section 3 of this Overview). 'Light regulation' pipelines are not subject to upfront price regulation. The light regulation model is more a negotiate-arbitrate approach, placing greater emphasis on commercial negotiation and information disclosure. The AER plays a role only if dispute resolution mechanisms are triggered.

4 AGN's proposal brings the two pipelines together under a single access arrangement. We approved this approach after consultation with stakeholders in early 2016: AER - *Direction to AGN to consolidate access arrangements for AGN's Victorian and Albury Networks* - 23 March 2016

submissions to us on both our draft decision and AGN's revised proposal. Subject to stakeholder interest, we will also consider holding a public forum following submission of AGN's revised proposal.

Following receipt of the revised proposal and submissions, we will then make our final decision taking into account the revised proposal, submissions and any other relevant information. Table 1-1 lists key dates and consultation deadlines for this review.

Table 1-1 Key dates and consultation timelines

Task	Date
Access arrangement revision proposal submitted to the AER	22 December 2016
Public forum	1 February 2017
Submissions on access arrangement proposal closed	3 March 2017
AER draft decision published	6 July 2017
Revised proposal due	14 August 2017
Submissions on draft decision and revised proposal close	15 September 2017
AER final decision published*	29 November 2017

* This date is indicative only.

1.1 Structure of this overview

This Overview provides a summary of our draft decision and its individual components:

- Section 2 provides a high level summary of our draft decision
- Section 3 sets out our draft decision on the reference services that will be covered by the access arrangement, and the mechanism for setting and varying reference tariffs.
- Section 4 sets out our draft decision on the total revenue requirement
- Section 5 provides a break-down of our revenue decision into its key components
- Section 6 sets out our draft decision on new incentive schemes to apply from 2018
- Section 7 sets out our draft decision on the non-tariff components of AGN's access arrangement proposal
- Section 8 explains our views on the regulatory framework and the NGO
- Section 9 outlines the consultation process we undertook in reaching our draft decision
- Appendix A lists the stakeholder submissions received on AGN's proposal.

In our attachments to this Overview we set out detailed analysis of the constituent components that make up our draft decision.

2 Draft decision

Our draft decision is to largely accept AGN's access arrangement proposal. This means AGN can recover $1200 million ($ nominal, smoothed) from consumers over the 2018–22 access arrangement period.

AGN's proposed operating expenditure (opex) for 2018–22 is in line with its expenditure in the current period, and 5.4 per cent lower than the opex forecast we included in its allowed revenue for 2013–17. AGN has proposed reductions to its capital expenditure (capex) compared to its current period expenditure, reflecting completion of most of its mains replacement program. However, this has been more than offset by a higher regulatory depreciation allowance, which largely accounts for the increase in total revenue compared to the current period.[5] Submissions were overwhelmingly in support of AGN's proposal notwithstanding this increase in revenue.

AGN engaged extensively with consumers and users of its networks in the development of its proposal. In June 2016—some six months prior to submission of its proposal—it published a 'draft plan' seeking views on the proposal it intended to submit to the AER. It is clear from submissions that these efforts were both valued and productive. AGN was rightly commended for:

> …one of the first regulatory proposals to seriously demonstrate consumer focussed engagement that has been subsequently implemented into the final proposal… a 'no shocks' regulatory proposal, an approach and attitude that we hope sets the approach for future network business regulatory proposals.[6]

As submissions also noted, AGN's engagement provided stakeholders with "a clear sense that "[AGN] knows who they are and where they are heading", which was not only instructive but built confidence that AGN's proposal was "much more genuine than ambit".[7] The AER Consumer Challenge Panel (CCP11) confirmed that AGN has clearly met its objective of presenting an access arrangement proposal which is underpinned by effective stakeholder engagement.[8]

AGN's approach, and its receptiveness to the feedback provided through its engagement, provided a strong, sound foundation for its proposal, and informed our assessment of it.

We have incorporated some minor modelling amendments identified and resolved in the course of our review. These reconcile the models AGN submitted with the intent of

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5 This difference includes the impact of inflation between periods.

6 Uniting Communities - *No Shocks AA Proposal: Submission to the AER regarding the AGN access arrangement proposal for Victoria Albury* - 19 April 2017, p. 2.

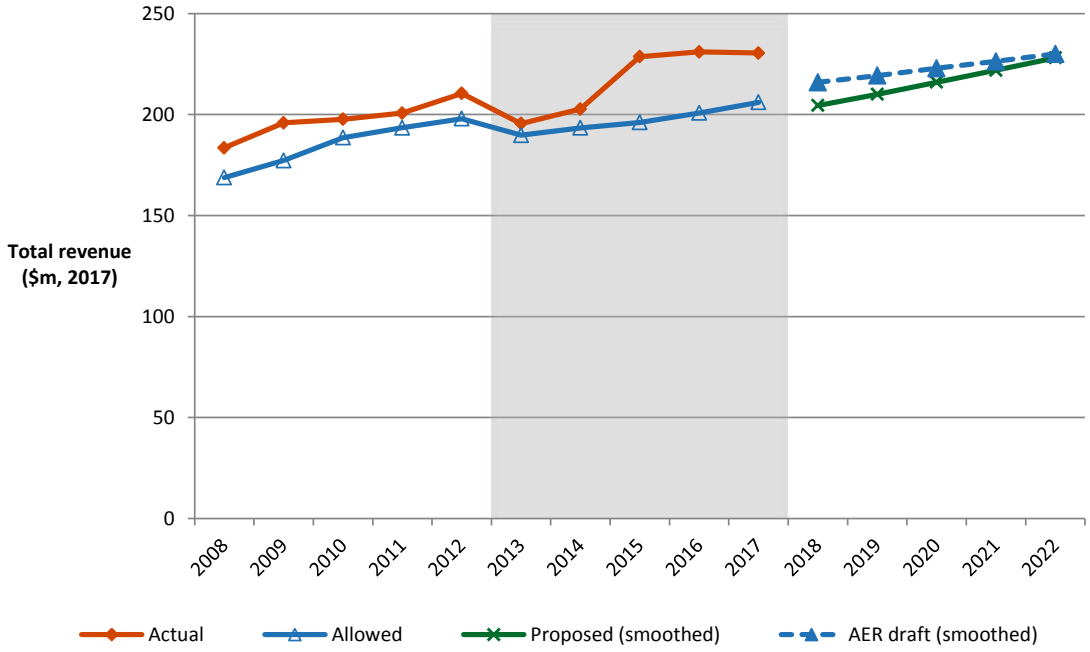
7 Uniting Communities - *No Shocks AA Proposal: Submission to the AER regarding the AGN access arrangement proposal for Victoria Albury* - 19 April 2017, pp. 2-3.

8 Consumer Challenge Panel (CCP 11) - *Response to proposals from AGN, AusNet and Multinet for the 2018-2022 Access Arrangements* - 3 March 2017, pp. 18-22, p. 5.

its proposal. Consistent with our usual practice (and as contemplated in AGN's proposal) we have also updated AGN's inputs to the calculation of the approved rate of return.

The total forecast revenue approved by us incorporates corrections and updates to AGN's proposal confirmed by AGN. It therefore provides for revenue 3.3 per cent higher than initially set out in AGN's proposal as it was submitted to us in December 2016. Figure 2-1 compares our draft decision on AGN's revenue for 2018–22 to its initial proposal, and to the revenue allowed and recovered during the current, 2013–17 access arrangement period.

Figure 2-1 AGN's past total revenue, proposed total revenue and AER draft decision total revenue ($ million, 2017)



Source: AER analysis.

Tariffs are derived from the total revenue requirement after consideration of demand for each tariff category. AGN operates under a weighted average price cap. This means the tariffs we determine (including the means of varying the tariffs from year to year) are the binding constraint across the 2018–22 access arrangement period, rather than the total revenue requirement set in our decision.[9]

[9] Where actual demand across the 2018–22 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.

In real dollar terms, the allowed forecast revenue requirement for 2018 in this draft decision will be 6.3 per cent less than AGN's actual revenue in 2017. In 2022, the allowed forecast revenue requirement will still be 0.2 per cent lower than AGN's actual 2017 revenue.

Because our corrections to AGN's modelling produce slightly higher revenue in our draft decision than AGN's proposal suggested, the reduction to revenues from 2017 to 2018 will be smaller than AGN's proposal suggested. However, increases in the following four years (from 2019 to 2022) will also be smaller than AGN proposed, keeping revenue (and therefore prices) relatively constant. Our estimates on how this will impact annual gas bills for residential and small business customers are set out in section 2.3 below.

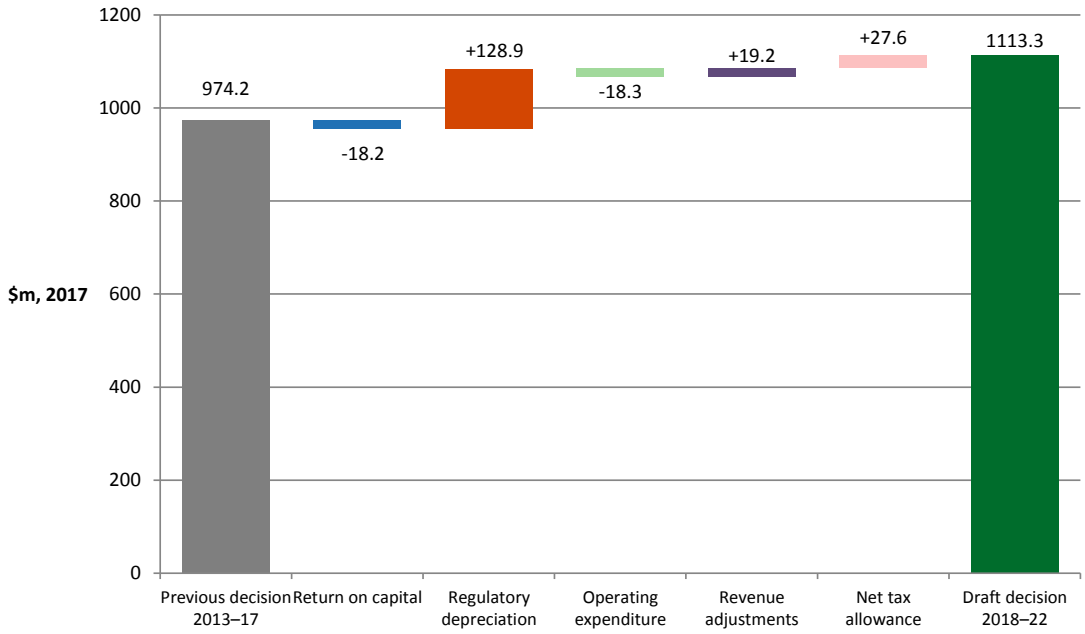
2.1 What is driving proposed revenue?

The impact of inflation makes it difficult to compare revenue across different time periods on a like-for-like basis. We therefore use real values based on a common year, which have been adjusted for the impact of inflation, to compare revenue from one access arrangement period to the next. In real dollar terms, our draft decision approves total revenue for the 2018–22 access arrangement period that is $128.2 million ($ 2017)—or 13.0 per cent—higher than the forecast total revenue requirement approved in our decision for 2013–17.[10]

Figure 2-2 compares our draft decision for the 2018–22 access arrangement period to AGN's allowed revenue for the current period, broken down by the various building block components that make up the forecast revenue allowance.

[10] The comparison of revenues between the 2018–22 and 2013–17 access arrangement periods is based on smoothed revenues. In nominal dollar terms, our draft decision revenues for the 2018–22 access arrangement period are about $229.6 million (or 23.7 per cent) higher than the average annual revenues approved for the 2013–17 access arrangement period.

Figure 2-2 AER's draft decision for the 2018–22 access arrangement period and AGN's 2013–17 allowed building block costs ($ million, 2017)



Source: AER analysis.

AGN has reported (opex) efficiencies in the current period, which are reflected in a lower opex forecast for 2018–22. The total forecast opex approved in this draft decision is 5.4 per cent lower than the opex forecast we included in AGN's approved revenue for 2013–17. While AGN expects to spend in line with its approved capex forecast for 2013–17, its capex forecast for 2018–22 is 6.7 per cent less than its actual expenditure in the current period.

As Figure 2-2 highlights, the key driver of the increase in revenue from the current period is the higher regulatory depreciation allowance (the return of capital) we have approved in this draft decision.

Regulatory depreciation is the amount used in the building block calculation of total revenue to ensure that AGN's revenue over time is consistent with the use of its capital base. Higher (or quicker) depreciation leads to higher revenue over this access arrangement period, but lower revenue in later periods.

The increase in AGN's regulatory depreciation allowance from the current, 2013–17 access arrangement period to our draft decision for 2018–22 reflects the following:

- In the current and previous access arrangement periods, AGN has undertaken a substantial mains replacement program to maintain the safety and security of its network. AGN will complete its low pressure mains replacement program by 2022. As it does this, depreciation of the assets it is replacing will be accelerated so that they are removed more quickly from the capital base or over a shorter period of time (see below).

- The return of capital building block increases as the capital base increases. AGN's capital base grew by 26.9 per cent in real terms over the current period, and is projected to grow by a further 8.4 per cent from 2018 to 2022.[11]
- AGN has also changed its approach to depreciation of assets, so that the same costs are recovered over a shorter period of time. AGN's new approach (often referred to as the 'year on year' approach) meets the criteria of the depreciation schedule reflecting assets' economic lives, where it tracks the asset's technical life. However, it does increase depreciation over the short to medium term. Other things being equal, this also increases prices. Our analysis suggests the impact in this case to be modest and therefore unlikely to have a significant impact on the efficient growth in the market for AGN's reference services.

This higher return *of* capital is offset to some extent by reductions in the return *on* capital. Higher (quicker) depreciation also causes the capital base to reduce more quickly (assuming no further capex). This reduces the return on capital allowance, although this impact is less than the higher depreciation allowance in the short to medium term.[12] The lower return on capital in this draft decision is driven primarily by a lower rate of return: 5.75 per cent (nominal), compared to 7.39 per cent in the current period.

2.2 Key differences between our draft decision and AGN's proposal

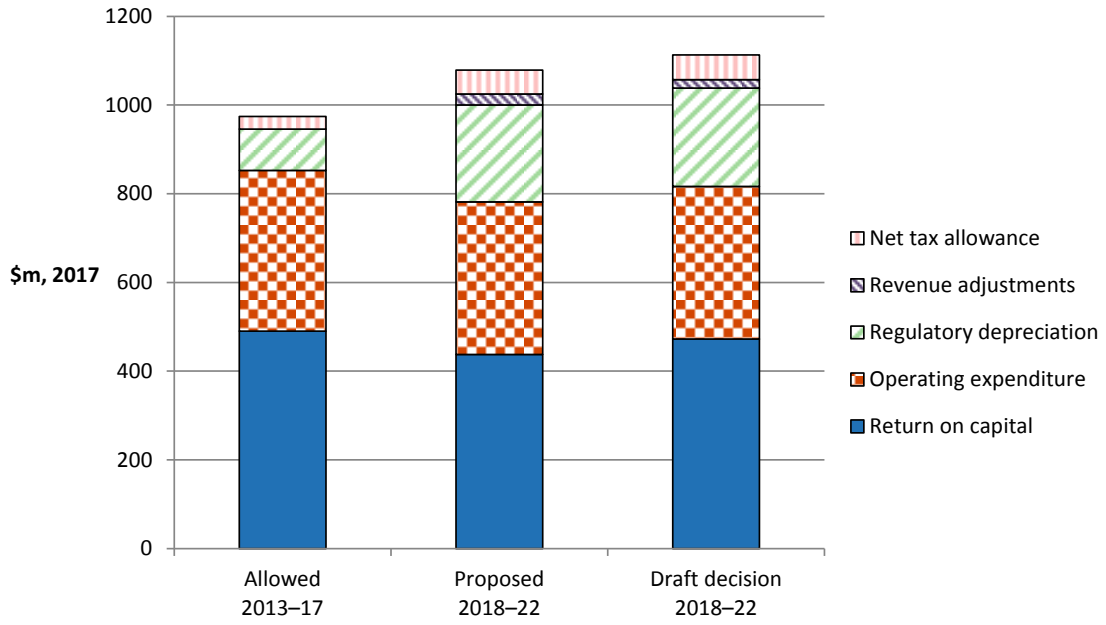
As we explained above, the $1200 million ($ nominal, smoothed) forecast revenue in this draft decision is 3.3 per cent higher than the $1162.2 million initially set out in AGN's proposal.

Figure 2-3 compares the building block revenue for the 2018–22 access arrangement period to that in AGN's proposal, and to the approved amount for the 2013–17 period.

[11] In nominal terms AGN's capital base grew by 39.1 per cent in 2013–17, and is projected to grow by 22.3 per cent from 2018 to 2022.

[12] This is generally the case because the reduction in the capital base amount feeds into the higher depreciation building block, whereas the reduced return on capital building block is proportionate to the lower capital base multiplied by the WACC.

Figure 2-3 AER's draft decision on components of total revenue ($ million, 2017)



Source: AER analysis.

The changes we have made are to reconcile the models AGN submitted with the intent of its proposal. We have worked with AGN to correct these errors, and in consultation with them have:

- made minor corrections to the modelling of its opening and closing capital base, which reduce both by 0.8 per cent.
- adjusted the calculation of the regulatory depreciation and corporate income tax allowances, which increase these allowances by 1.7 per cent and 4.7 per cent respectively.

Consistent with our usual practice (and as contemplated in AGN's proposal) we have also updated AGN's inputs to the calculation of the approved rate of return, taking into account more recent data. Our draft decision therefore applies a rate of return of 5.75 per cent, compared to the placeholder of 5.28 per cent in AGN's proposal. The rate of return will be updated again for our final decision.

AGN now has the opportunity to incorporate these amendments in a revised proposal prior to our final decision.

2.3 Impact of our draft decision on gas bills

The annual gas bill for customers in Victoria reflects the combined cost of all the gas supply chain components. Changes in gas bills over time reflect movements in one or more of the components in the bill. The main components are:

- the cost of purchasing gas (the wholesale energy cost)

- the cost of the pipelines used to transport the gas (the transmission and distribution networks), and other infrastructure such as metering cost;
- the retailer's costs and profit margin.

Our decision on AGN's access arrangement will affect the component of the bill related to distribution pipelines. For customers on AGN's network distribution charges account for approximately 25 per cent of an average residential customer's annual gas bill and approximately 15 per cent of an average small business customer's annual gas bill.[13]

We estimate the bill impact by varying the distribution charges in accordance with our draft decision, while holding other components of the bill constant. Our estimates are in nominal terms (taking into account expected future inflation to determine what the nominal price levels will be in future periods) because it will be nominal amounts that consumers will be paying.

Based on this approach, we expect that our draft decision would result in the distribution component of the average annual residential gas bills for AGN customers rising by less than expected inflation over the 2018–22 access arrangement. The distribution component of the average annual residential gas bill in 2018 is expected to be about $13 ($ nominal) below the current 2017 level. By the end of the 2018–22 access arrangement period, the distribution component of the average annual bill is expected to be about $35 ($ nominal) above current levels. Similarly, the distribution component of the average annual small business gas bill in 2018 is expected to be around $35 ($ nominal) lower than in 2017, and about $93 above the current 2017 level by 2022. These estimates are indicative only, and individual customers' actual bills will also depend on their usage patterns and the structure of their chosen retail tariff offering.

Table 2-1 shows our estimated impact of this draft decision over the 2018–22 access arrangement period compared with AGN's proposal on the average annual gas bills for residential and small business customers on AGN's network.

[13] Proportions based on average annual distribution charges calculated within the PTRM and average standing residential offers at June 2017 on Switch On comparison tool and Energy Made Easy website (for Albury region) using average annual consumption used in the PTRM for each of AGN's tariff zones (postcodes 3053, 3561, 3683, 3875 and 2640).

Table 2-1 AER's estimated impact of our draft decision and AGN's proposal on the average annual gas bills for the 2018–22 access arrangement period ($ nominal)

	2017	2018	2019	2020	2021	2022
AER draft decision						
Residential annual gas bill	1244[a]	1231	1242	1254	1266	1279
Annual change[c]		–13 (–1%)	11 (0.9%)	12 (0.9%)	12 (1%)	13 (1%)
Small business annual gas bill	5493[b]	5458	5489	5520	5552	5586
Annual change[c]		–35 (–0.6%)	31 (0.6%)	31 (0.6%)	32 (0.6%)	34 (0.6%)
AGN proposal						
Residential annual gas bill	1244[a]	1214	1228	1243	1258	1275
Annual change[c]		–30 (–2.4%)	14 (1.2%)	15 (1.2%)	15 (1.2%)	17 (1.3%)
Small business annual gas bill	5493[b]	5415	5452	5491	5532	5575
Annual change[c]		–78 (–1.4%)	37 (0.7%)	39 (0.7%)	41 (0.7%)	43 (0.8%)

Source: AER analysis, Switch On comparison tool, www.compare.switchon.vic.gov.au; Energy Made Easy, www.energymadeeasy.gov.au.

(a) Based on average standing residential offers at June 2017 on Switch On comparison tool and Energy Made Easy website (for Albury region) using average annual consumption calculated in the PTRM for each of AGN's tariff zones (postcodes 3053, 3561, 3683, 3875 and 2640).

(b) Based on average standing small business offers at June 2017 on Switch On comparison tool and Energy Made Easy website (for Albury region) using average annual consumption calculated in the PTRM for each of AGN's tariff zones (postcodes 3053, 3561, 3683, 3875 and 2640).

(c) Annual change amounts and percentages are indicative. They are derived by varying the distribution component of 2017 bill amounts by the nominal weighted average expected change in tariffs. Actual bill impacts will vary depending on consumption and tariff class.

We do not expect gas distribution charges flowing from this draft decision will be a notable contributor to overall gas bill changes.

While our approach isolates the effect of our decision on gas prices, it does not imply that other components will remain unchanged across the access arrangement period.

Wholesale gas costs make-up a smaller percentage of the retail gas prices paid by consumers. AEMO's modelling forecasts retail prices to rise on average by 2.1 per cent per annum (in real dollar terms) for residential customers, driven mainly by

wholesale prices.[14] Modelling by the Australian Energy Market Operator (AEMO) projects that the delivered wholesale cost of gas in Australia will increase by 48 per cent by 2036.[15]

[14] AEMO, *National Gas Forecasting Report for Eastern and Southern Australia*, December 2016, p. 26.

[15] AEMO, *National Gas Forecasting Report for Eastern and Southern Australia*, December 2016, p. 7

3 Reference services and tariffs

3.1 Services covered by the access arrangement

An access arrangement sets out at least one service likely to be sought by a significant part of the market (reference services). For each reference service, including services ancillary to the reference service, the access arrangement specifies the reference tariff and the other terms and conditions on which these services will be provided.[16]

AGN is to provide access to its reference services, but may negotiate alternative terms and conditions at alternative prices with users. AGN may also offer other non-reference services (negotiated services) which are not subject to the same level of regulation under the access arrangement. We may be called upon to determine the tariff and other conditions of access to services if an access dispute arises.[17]

Our draft decision approves AGN's proposal to continue to offer the same reference services and ancillary reference services in 2018–22 as it has in the current, 2013–17 period, these being:

- haulage reference services:
    - delivery of gas to those customers who use less than 10 terajoules per annum
    - meter provision and data services
- ancillary reference services:
    - Meter and gas installation test—on-site testing to check the measurement accuracy of the meter
    - Disconnection—disconnection by installation of locks or plugs on a meter
    - Reconnection—reconnection by removal of locks or plugs on a meter
    - Meter removal—removing a meter at a premise
    - Meter reinstallation—reinstating a meter at a premise
    - Special meter read—Reading of a meter in addition to a scheduled meter reading.

[16] NGR, r. 48.

[17] NGL, Chapter 6.

3.2 Reference tariff setting and the reference tariff variation mechanism

Our draft decision on AGN's proposed access arrangement includes decisions on the structure of its reference tariffs and the mechanism by which those tariffs will be determined from year to year (the annual reference tariff variation mechanism).

We accept AGN's proposal to maintain a weighted average price cap tariff variation mechanism for its haulage reference services.[18] This means that prices will not be impacted by within-period changes in demand, and AGN will continue to have incentives to maintain (or grow) gas consumption and thereby achieve scale efficiencies and reduce unit costs. While we generally accept the form of the mechanism, our draft decision sets out amendments to AGN's proposed control formulae that will:

- change the timing of the CPI escalation adjustment to reduce the administrative burden relative to AGN's proposed approach. This change also allows greater transparency in the annual tariff variation proposal.
- amend AGN's proposed combined single adjustment factor—which would allow AGN to adjust its revenues in relation to a number of possible but not yet known annual costs—so that it is clear that it will not operate where we have:
    - made provision for these costs in AGN's opex forecast ,
    - not accepted the proposed costs, or
    - accounted for the costs through an alternative adjustment mechanism.

Our draft decision also updates the cost pass through events that will apply to AGN in the 2018–22 access arrangement period. This aligns the treatment of common risks between AGN and the other Victorian gas distributors (AusNet and Multinet) and between Victoria's gas and electricity distribution networks.

3.3 Forecast demand

Demand is an important input into the derivation of AGN's reference tariffs. In simple terms, tariffs are determined by dividing cost (as reflected in forecast revenue) by total demand (GJ/day), so that an increase in forecast demand has the effect of reducing the tariff price and vice versa. Forecast demand also affects the forecasts of operating and capital expenditure (new connections) that form part of our decision on the total revenue requirement.

Our draft decision is to accept AGN's proposed demand forecasts, which include:

[18] NGR, r. 97(2).

- a decrease in total residential gas demand (AGN's Tariff R) of around 0.2 per cent per year over 2018-22 access arrangement period.[19] This compares to 0.6 per cent per year in the current period.[20] This relatively flat state of growth is due to forecast reductions in consumption per connection of 2.2 per cent per year being offset by net customer growth of 2 per cent per year.[21]
- an increase in total commercial demand (AGN's Tariff C) of 0.2 per cent over the 2018-22 access arrangement period.[22] This compares to 0.8 per cent per year in the current period. This slight growth is due to a fall of 0.5 per cent per year in consumption per connection being offset by increases in commercial net connections of 0.7 per cent per year.[23]
- an increase in industrial demand of 0.1 per cent over the 2018-22 access arrangement period. This compares to an increase of 0.9 per cent per year in the current period.

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19 AGN - *Final Plan - Access Arrangement Information for our Victorian and Albury natural gas distribution networks 2018-2022* - 20161222, p. 157.

20 Note that figures in the current period include estimated values for 2017.

21 AGN - *Final Plan - Access Arrangement Information for our Victorian and Albury natural gas distribution networks 2018-2022* - 20161222, p. 156.

22 AGN - *Final Plan - Access Arrangement Information for our Victorian and Albury natural gas distribution networks 2018-2022* - 20161222, p. 159.

23 AGN - *Final Plan - Access Arrangement Information for our Victorian and Albury natural gas distribution networks 2018-2022* - 20161222, p. 159.

4 Total revenue requirement

The total revenue requirement is a forecast of the efficient cost of providing gas distribution services over the access arrangement period. We determine annual revenue—and the total revenue requirement—in nominal terms because it will be in nominal amounts that consumers will be paying. To do this, we take into account expected future inflation to determine what the nominal price levels will be in future periods. Our draft decision uses 10 year inflation expectations on average to convert revenues to nominal values.

Tariffs are derived from the total revenue requirement after consideration of demand for each tariff category. AGN operates under a weighted average price cap. This means the tariffs we determine (including the means of varying the tariffs from year to year) are the binding constraint across the 2018–22 access arrangement period, rather than the total revenue requirement set in our decision.[24] Tariffs are adjusted each year using the 'X factors'. X factors are percentage changes in real weighted average tariffs from year to year. The process of determining X factors is discussed in section 4.3.

4.1 The building block approach

We have employed the building block approach to determine AGN's total revenue requirement—that is, we based the total revenue requirement on our estimate of the efficient costs that AGN is likely to incur in providing its reference services. The building block costs, as shown in Figure 4-1, include:[25]

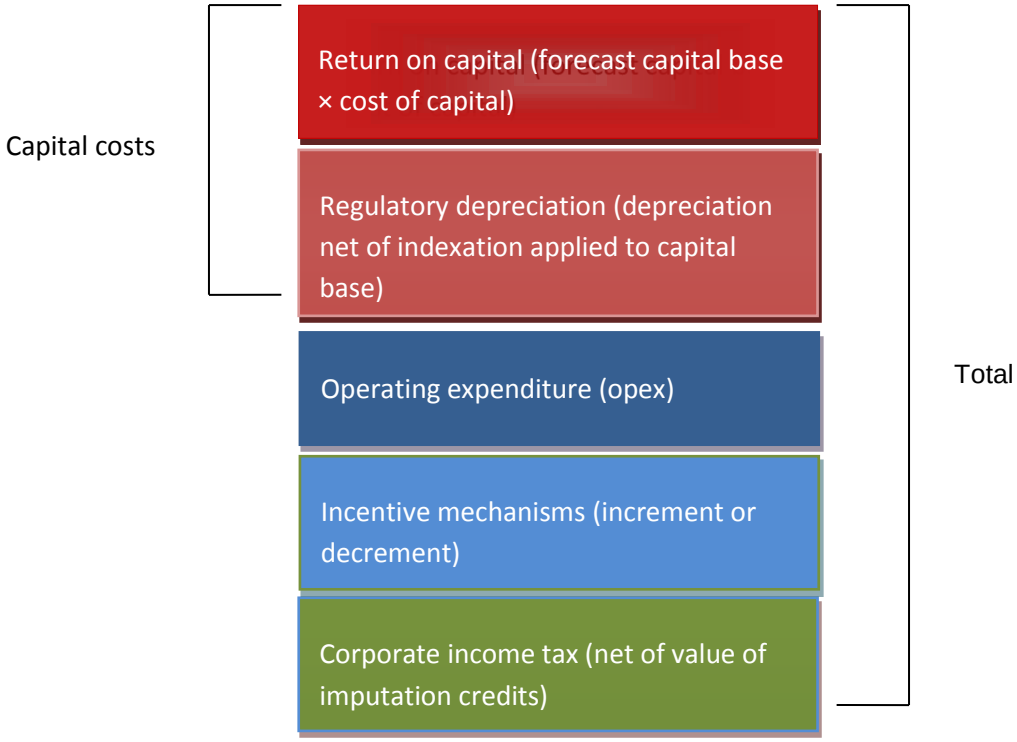
- return on the projected capital base (return on capital)
- depreciation of the projected capital base (return of capital)
- the estimated cost of corporate income tax
- revenue increments or decrements resulting from incentive schemes such as the efficiency carryover mechanism
- forecast opex.

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.

[24] Where actual demand across the 2018–22 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.

[25] NGR, r. 76.

Figure 4-1 The building block approach to determining total revenue



4.2 Draft decision

Our draft decision sets out a number of amendments to the building block inputs making up AGN's proposed total revenue requirement (smoothed) of $1162.2 million ($ nominal). We expand on these in section 5. Based on our assessment of the building block costs,[26] we determine a slightly higher smoothed total revenue requirement of $1200 million ($ nominal).[27]

It follows that our draft decision requires amendments to the 2018 tariffs set out in AGN's proposal, which was for a weighted average decrease in real tariffs of 11.5 per cent. We also require consequential amendments to AGN's proposed 2018–22 tariff path, which was for a weighted average increase in real tariffs of 2.5 per cent per year from 2019 onwards. As a result of our higher total revenue requirement, our draft decision is for a real decrease in weighted average tariffs of 6.4 per cent in 2018, followed by increases of 1.25 per cent in each of the remaining years of the access arrangement period. Section 4.3 explains our approach to revenue equalisation (smoothing) and tariffs.

[26] NGR, r. 76.

[27] This is calculated by smoothing the unsmoothed building block revenue for the 2018–22 access arrangement period as set in this draft decision.

Table 4-1 sets out our draft decision on AGN's total revenue requirement, by building block, for each year of the 2018–22 access arrangement period, the total revenue after equalisation (smoothing) and the X factors for use in the tariff variation mechanism.

Table 4-1 AER's draft decision on AGN's smoothed total revenue and X factors for the 2018–22 access arrangement period ($ million, nominal)

Building block	2018	2019	2020	2021	2022	Total
Return on capital	92.2	96.7	102.2	106.9	110.9	508.9
Regulatory depreciation	40.3	46.2	54.9	46.5	51.1	238.9
Operating expenditure	68.8	71.3	73.9	76.7	79.7	370.4
Revenue adjustments	13.3	5.3	3.4	–2.3	0.0	19.8
Corporate income tax	12.7	13.0	13.3	10.0	10.8	59.9
Building block revenue – unsmoothed (including ARS)	**227.3**	**232.5**	**247.6**	**237.9**	**252.5**	**1197.8**
Less: Ancillary reference services	4.0	4.2	4.3	4.4	4.6	21.6
Building block revenue - unsmoothed (excluding ARS)	223.2	228.4	243.3	233.4	247.9	1176.2
Building block revenue – smoothed (excluding ARS)	217.2	226.0	235.4	244.9	255.0	1178.5
X factor[a]	**6.44%**	**–1.25%**	**–1.25%**	**–1.25%**	**–1.25%**	**n/a**
Inflation forecast	2.45%	2.45%	2.45%	2.45%	2.45%	n/a
Nominal price change	–4.1%	3.7%	3.7%	3.7%	3.7%	n/a
Building block revenue - smoothed (including ARS)	**221.3**	**230.2**	**239.7**	**249.3**	**259.6**	**1200.0**

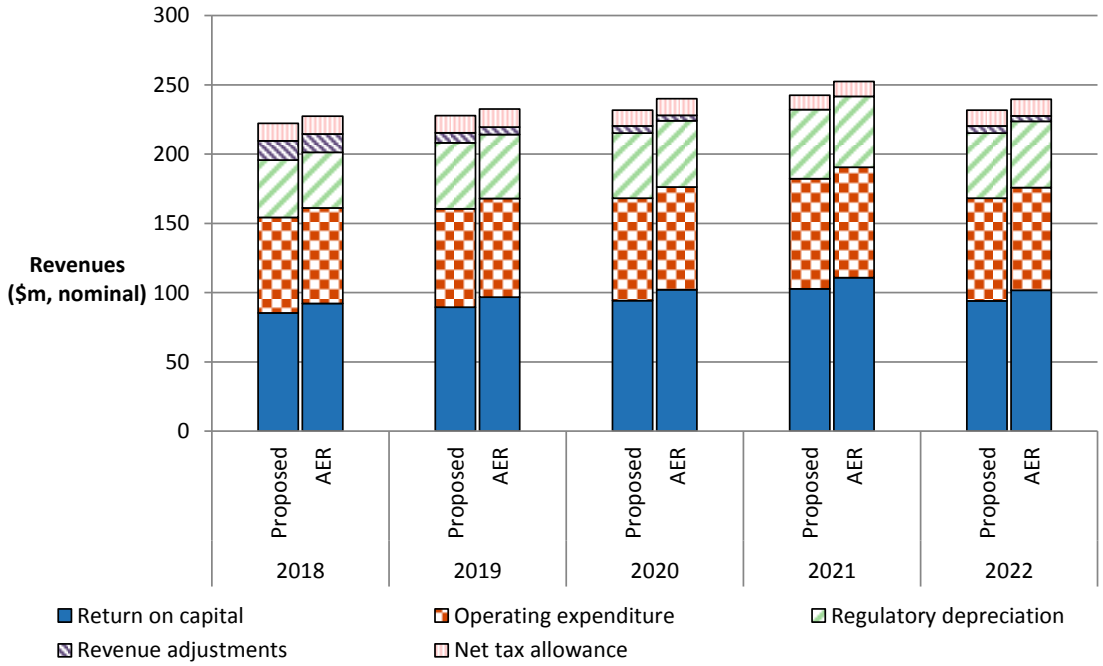
Source: AER analysis.

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 factor for 2018 is indicative only. The draft decision establishes 2018 tariffs directly, rather than referencing a change from 2017 tariffs.

Figure 4-2 shows the effect of our draft decision adjustments on AGN's proposed building blocks for each year of the 2018–22 access arrangement period. It shows the increases to AGN's proposed return on capital, depreciation and tax building blocks.

Figure 4-2 AER's draft decision and AGN's proposed building block revenue (unsmoothed) ($ million, nominal)



Source: AER analysis.

AGN noted in its proposal that we should consider whether our decision provides sufficient cash flow for a business to achieve the assumed credit rating used to determine the allowed return on debt. AGN suggested that credit ratios should be monitored closely as part of the decision-making process and if necessary, an adjustment that alters the timing of cash flows applied. It noted that this type of analysis is undertaken by other regulatory bodies such as Ofgem in the UK.[28] We note the financeability and credit ratio issues raised by AGN are very similar to those we recently considered in our decision for AGN's 2016–21 South Australian access arrangement. As discussed in further detail in our recent decision on AGN's South Australian access arrangement, Ofgem requires firms in the first instance to manage their own financeability problems, where possible, through equity raising or reduced dividends.[29] Consistent with our decision on AGN South Australian access arrangement, we are not satisfied that AGN's analysis of credit metrics provides robust evidence of a negative credit rating outcome for an efficient service provider.[30] We also consider that AGN's proposed approach to the use of credit metrics is an indirect test

[28] AGN, *Final Plan - Access Arrangement Information for our Victorian and Albury natural gas distribution networks 2018-2022 - 20161222*, pp. 146–147.

[29] AER, *Draft Decision Australian Gas Networks access arrangement - Attachment 3 - Rate of return*, November 2015, p. 222; AER, *Final Decision Australian Gas Networks access arrangement - Attachment 5 - Regulatory depreciation*, May 2016, pp. 62–64.

[30] AER, *Final Decision Australian Gas Networks access arrangement - Attachment 5 - Regulatory depreciation*, May 2016, pp. 20–22.

on the return on equity and remain unpersuaded by the submission that low credit metrics indicate the need for an adjustment to cash flows.[31] Overall, we are satisfied that our draft decision allows for AGN's reasonable needs for cash flow to meet financing, non-capital and other costs.[32]

4.3 Revenue smoothing and tariffs

After our assessment of AGN's total building block revenue (unsmoothed revenue), we determined the smoothed revenue profile across the 2018–22 access arrangement period.[33] AGN operates under a weighted average price cap. This means that under its tariff variation mechanism we determine the weighted average tariff change each year. This weighted average tariff change is labelled the 'X factor'. The X factors that we determine must ensure that the sum of the smoothed revenues across the period equals the unsmoothed building block revenue in net present value (NPV) terms.

The X factors represent the weighted average real change in tariffs. As part of the annual reference tariff variation process, we combine the X factors we have determined in our decision with actual inflation to create reference tariffs for the coming year. This means that the prices paid by consumers, and therefore the revenues received by the networks, change with actual inflation, but (ignoring other non-inflation factors) are constant in real terms.

Table 4-2 presents our draft decision X factors, and compares them to AGN's proposal.

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31 AER, *Final Decision Australian Gas Networks access arrangement - Attachment 5 - Regulatory depreciation*, May 2016, pp. 72–73.

32 NGR, r. 89(1)(e).

33 This process of smoothing revenues is described in the NGR as 'revenue equalisation'. NGR, r. 92.

Table 4-2 Weighted average tariff change across the access arrangement period (X factors) — comparison of AGN's proposal and AER's draft decision (per cent)

	2018	2019	2020	2021	2022
AER draft decision					
X factor[a]	6.44%	–1.25%	–1.25%	–1.25%	–1.25%
Nominal price change	–4.1%	3.7%	3.7%	3.7%	3.7%
AGN proposal					
X factor[a]	11.49%	–2.45%	–2.45%	–2.45%	–2.45%
Nominal price change	–9.3%	5.0%	5.0%	5.0%	5.0%

Source: AER analysis

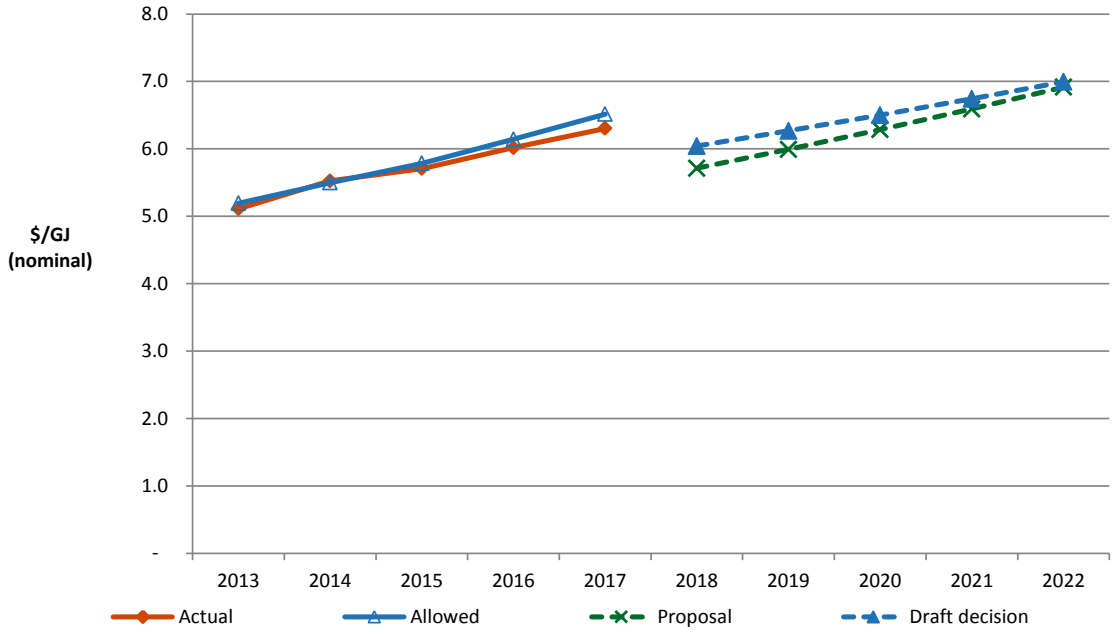
(a) Under the CPI–X form of control, a positive X factor is a decrease in price (and therefore in revenue). For example, an X factor of 6.44 per cent in 2018 means a real price decrease of 6.44 per cent that year. After consideration of inflation (assumed at 2.45 per cent) this becomes a nominal price decrease of 4.1 per cent.

(b) For comparison purposes the nominal price changes are derived from the real price changes for AGN adjusted by AER's draft decision forecast inflation of 2.45 per cent.

Figure 4-3 shows indicative tariff paths for AGN's reference services from 2013 to 2022. It compares AGN's proposed tariff path with that approved for the 2013–17 access arrangement, and with this draft decision.[34] This provides a broad overall indication of the average movement across several access arrangement periods.

[34] The tariff path for 2013–22 uses actual inflation outcomes for the 2013–17 period, and forecast inflation for 2018–22.

Figure 4-3 Indicative reference tariff paths for AGN's reference services from 2013 to 2022 ($/GJ)



Source: AER analysis;

AGN's proposed tariff path suggested a decrease of 9.3 per cent (in nominal terms) in 2018, followed by tariffs that increase at an average of 5.0 per cent per year for the remaining years of the 2018–22 access arrangement period. Our draft decision provides for higher total smoothed revenue than AGN's proposal, in line with our amendments to total unsmoothed revenue. As such, a smaller decrease of 4.1 per cent to tariffs is required at the start of the 2018–22 access arrangement period to reflect the change in smoothed revenue from the 2013–17 access arrangement period. This is followed by small increases in subsequent years of 3.7 per cent per annum.

In choosing the smoothing profile for this draft decision we have balanced a number of competing objectives:

- Equalising (in NPV terms) unsmoothed and smoothed revenue
- Providing price signals that reflect the underlying efficient costs
- Minimising tariff variability from 2017 and within the 2018–22 access arrangement period
- Minimising the likelihood of variability in tariffs at the start of the 2023–27 access arrangement period.

Each of these points is discussed in turn.

First, we are satisfied that our draft decision tariff path for AGN's 2018–22 access arrangement period achieves revenue equalisation as required by rule 92(2) of the NGR.[35] As set out above, we have made a small adjustment to the unsmoothed revenue proposed by AGN. Accordingly, we set the tariff path so that it adjusts the smoothed revenue upwards 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 in achieving the NGO and the revenue and pricing principles by providing a price signal that facilitates efficient use of natural gas services.[36] Our draft decision tariff path shows a smaller decrease in the first year of the 2018-22 access arrangement period, reflecting the minimal change to unsmoothed building block costs.

Third, in setting the tariff path, we aim to minimise tariff volatility from 2017 to 2018 and within the 2018–22 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 2017 would better minimise volatility within the 2018-22 access arrangement period, but would not achieve revenue equalisation between tariffs and costs.

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 with certainty what AGN's efficient costs will be in 2023 or across the 2023–27 access arrangement period more generally. The unsmoothed building block costs for 2022 (the last year of AGN's 2018–22 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 we assume no significant changes in forecast costs from 2022 to 2023, this final year divergence gives us an estimate of the size of the tariff change at the start of the 2023–27 access arrangement period.

For this draft decision, this final year divergence is just under 3 per cent. The divergence is within our usual target range of 3 per cent, and less than the divergence proposed by AGN of 6.0 per cent. The profile of unsmoothed building block revenues and forecast demand constrain our ability to smooth the revenues without causing significant tariff volatility. Working with these constraints, our draft decision is to give primary weight to smoothing tariffs within the 2018–22 access arrangement period, while minimising the final year divergence of smoothed revenue and unsmoothed revenues to the extent possible. We note that if there are significant changes in costs at the start of the 2023–27 access arrangement period, this might increase or decrease the required tariff change at that time.

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

[36] NGL, rr. 23, 24.

Finally, we also considered AGN's preference for the tariff path.[37] AGN noted its preference that the tariff path be aligned with the growth in the forecast capital base over the 2018–22 access arrangement period.[38] We consider that the draft decision tariff path largely reflects this preference. We note the average real growth in the forecast capital base set in this final decision is about 1.6 per cent per year. Our tariff path provides for an initial decrease of 6.4 per cent in 2018 and then allows 1.25 per cent increase per year (in real terms) in the last four years of the 2018–22 access arrangement period.

We are satisfied that our draft decision tariff path reflects our balanced consideration of these competing objectives. We will review this smoothing profile for the final decision if necessary.

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

[38] AGN, *Final Plan - Access Arrangement Information for our Victorian and Albury natural gas distribution networks 2018-2022 - 20161222*, p. 146.

5 Key elements of our draft decision on revenue

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

The following sections summarise our revenue decision by building block. The attachments to this draft decision provide a more detailed explanation of our analysis and findings.

5.1 Capital base

The capital base roll forward accounts for the value of AGN's regulated assets over the access arrangement period. The opening capital base value for a regulatory year within the access arrangement period is rolled forward by indexing it for inflation, adding any conforming capex, and subtracting depreciation and other possible factors (for example, disposals or customer contributions).[39] Following this process, we arrive at a closing value of the capital base at the end of each year of the access arrangement period. The opening value of the capital base is used to determine the return of capital (regulatory depreciation) and return on capital building block allowances.

We determine an opening capital base of $1602.8 million ($ nominal) as at 1 January 2018, which is $12.7 million (or 0.8 per cent) less than that proposed by AGN. This is because we have worked with AGN to correct some inputs and modelling errors in the roll forward model (RFM) provided with its proposal.

Table 5-1 summarises our draft decision on the roll forward of AGN's capital base during the 2013–17 access arrangement period.

[39] The term 'rolled forward' means the process of carrying over the value of the capital base from one regulatory year to the next.

Table 5-1 AER's draft decision on AGN's capital base roll forward for the 2013–17 access arrangement period ($ million, nominal)

	2013	2014	2015	2016	2017
Opening capital base	1152.2	1237.0	1331.4	1439.5	1511.9
Net capex	103.0	113.1	128.5	105.8	121.1
Indexation of capital base	23.1	26.7	30.7	21.6	19.6
Less: straight-line depreciation	41.3	45.4	51.1	55.0	58.4
Closing capital base	1237.0	1331.4	1439.5	1511.9	1594.2
Difference between estimated and actual capex in 2012					6.3
Return on difference for 2012 capex					2.4
Opening capital base as at 1 January 2018					**1602.8**

Source: AER analysis.

Our draft decision also differs from AGN's proposed roll forward of its projected capital base over the 2018–22 access arrangement period, and its closing capital base at 31 December 2022 of $1977.2 million ($ nominal). This is because of our corrections to AGN's proposed inputs to the projected capital base roll forward, specifically the opening capital base, forecast capex modelling and depreciation. Based on our draft decision on these inputs, we determine a projected closing capital base of $1960.5 million ($ nominal) as at 31 December 2022. This is $16.7 million ($ nominal) less than that proposed by AGN, a reduction of 0.8 per cent.

Table 5-2 sets out the projected roll forward of the capital base during the 2018–22 access arrangement period.

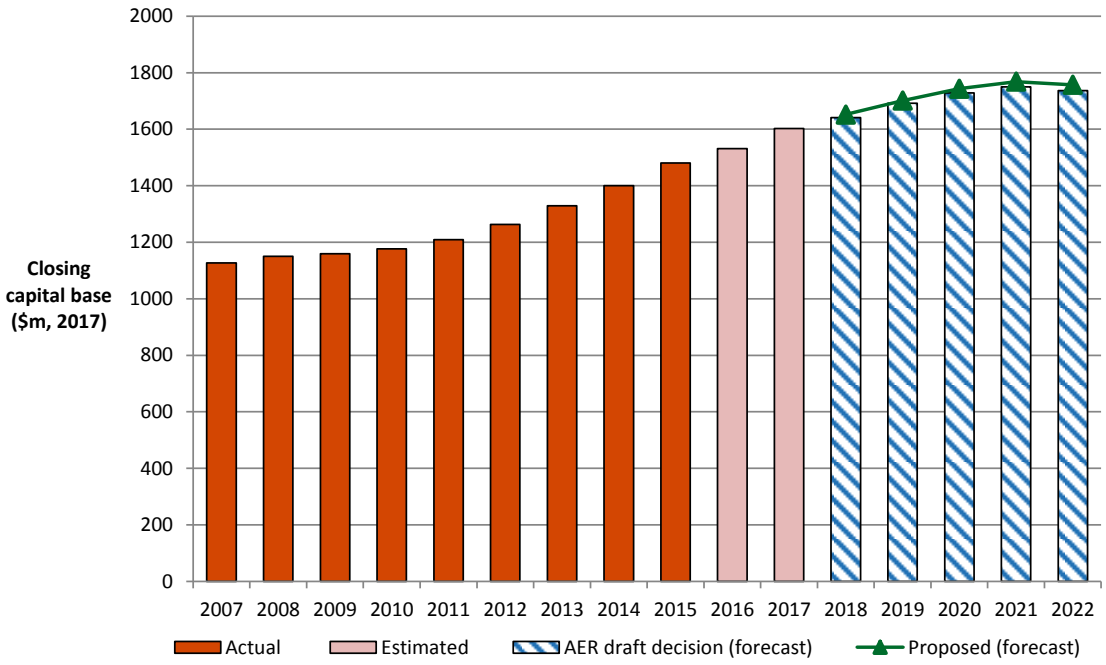
Table 5-2 AER's draft decision on AGN's projected capital base roll forward for the 2018–22 access arrangement period ($ million, nominal)

	2018	2019	2020	2021	2022
Opening capital base	1602.8	1681.3	1776.1	1858.6	1927.5
Net capex	118.7	141.0	137.4	115.3	84.1
Indexation of capital base	39.3	41.2	43.5	45.5	47.2
Less: straight-line depreciation	79.5	87.4	98.4	92.0	98.3
Closing capital base	1681.3	1776.1	1858.6	1927.5	1960.5

Source: AER analysis.

Figure 5-1 compares our draft decision on AGN's forecast capital base to AGN's proposal and actual capital base in real dollar terms.

Figure 5-1 AGN's actual, proposed forecast, and AER draft decision forecast capital base ($ million, 2017)



Source: AER analysis.

5.2 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 RAB.

We are satisfied that the allowed rate of return of 5.75 per cent (nominal vanilla) we determined contributes to the achievement of the NGO, and achieves the allowed rate of return objective (ARORO) set out in the NGR.[40] 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.[41]

Table 5-3 sets out our rate of return and AGN's proposed rate of return.

[40] NGR, cl. 87(2).
[41] NGR r. 87(3).

Table 5-3 Draft decision on AGN's rate of return (% nominal)

	Previous allowed return (2013-17)	AGN's proposal (2018-22)	AER draft decision (2018)	Allowed return over 2018 regulatory control period
Return on equity (nominal post–tax)	8.33	6.58	7.2	Constant (7.2%
Return on debt (nominal pre–tax)	6.76	4.42	4.79	Updated annually
Gearing	60	60	60	Constant (60%)
Nominal vanilla WACC	7.39	5.28	5.75	Updated annually for return on debt
Forecast inflation	2.5	2.39	2.45	Constant (%)

Source: AER analysis; AGN, *Final plan attachment 10.1 Financing Costs*, December 2016, p. 17, 21, 44.

Our return on equity estimate for this draft decision is 7.2 per cent. We derived this estimate by applying the foundation model approach (as set out in the Guideline) used to determine the allowed return on equity in our most recent decisions.[42] AGN has also adopted this approach.[43] This is a six step process, where we have regard to a considerable amount of relevant information, including various equity models.

Our return on equity point estimate and the parameter inputs are set out in the table below.

[42] For example, see AER, *Final decision: AusNet Services determination 2015 -16 to 2019–20, Attachment 3—Rate of return*, May 2016.

[43] AGN, Final plan a*ttachment 10.1 Financing Costs*, December 2016, p. 5.

Table 5-4 Draft decision on AGN's return on equity (% nominal)

	AER previous decision (2013–17)	AGN's proposal (2018–22)	AER draft decision (2017-18)
Nominal risk free rate (return on equity only)	3.53%	2.03%[a]	2.6%[b]
Equity risk premium	4.8%	4.55%	4.55%
Market risk premium	6%	6.50%	6.5%
Equity beta	0.8	0.7	0.7
Nominal post–tax return on equity	8.33%	6.58%[(c)]	7.2%

Source: AER analysis; AGN, *Final plan attachment 10.1 Financing Costs*, December 2016, p. 17, 21, 44.

[a] Based on AGN's indicative averaging period adopted for its proposal of 20 business days to 30 September 2016.

[b] Calculated with a placeholder averaging period of 20 business days up to 28 April 2017.

Our return on debt estimate is based on a gradual transition from the 'on-the-day' approach we used in the past to the 'trailing average' approach we proposed in the Guideline. The trailing average approach reflects the return on debt that a network business would face if it raised debt annually in equal parcels. Our return on debt approach incorporates a transition to the new approach.

Our decision is also to update the return on debt annually. Therefore, our estimate in this decision is for the first year of the regulatory period. Due to this, we update our rate of return annually.

We commence the trailing average with an initial estimation of the return on debt that is then progressively updated over the regulatory period. In practice, this means that for new debt that is issued (10 per cent of the initial estimate each year) we apply an estimate of the observed return on debt immediately. For existing debt issued before the commencement of the trailing average approach, we will continue to apply the on-the-day approach for the portion that has not been updated. Consequently, at the end of 10 years the total debt portfolio will have been updated and incorporated into the trailing average.

Our return on debt estimate is developed on the basis that a benchmark efficient entity issues debt with a 10 year term and has a BBB+ credit rating. To estimate the yield on this debt, we use an independent third party data service provider. We have reviewed the recent draft proposals and decided to adopt a simple average of the data series provided by the Reserve Bank of Australia and Bloomberg.

Our estimation procedure allows the service provider to propose a period between 10 business days and 12 months in length before the start of each regulatory year, over which the observed rates are averaged to estimate the return on debt. This results in service providers proposing an averaging period consistent with its debt practices and therefore, our return on debt estimate is different for different service providers.

Our return on debt estimate for the first year of AGN's access arrangement period in this draft decision is 4.79 per cent. This return on debt number will be updated annually during the regulatory period to partially reflect prevailing interest rates. Our approach and estimation procedures are consistent with the Guideline. We note that AGN in its current draft proposal adopted our return on debt approach as set out in the Guideline and proposed a return on debt of 4.42 per cent. We note the differences in the return on debt number reflect different averaging periods used for the estimation of the rates in the revenue proposal and the AER's draft decision. We also note, in line with the Guideline approach the AER has followed, AGN proposed updating of the return on debt for the final agreed averaging period.

Our estimate of expected inflation is estimated as the geometric average of 10 annual expected inflation rates. We use the RBA's forecasts of inflation for the first two annual rates and the mid-point of the RBA's inflation target band for the remaining eight annual rates.

AGN proposed estimating expected inflation using this approach. We have accepted this proposal. We are currently conducting an industry-wide review of inflation. That review is yet to be finalised and so findings from the review cannot be included in this draft decision. Findings from the review may inform our final decision.

Further detail on our draft decision in regards to AGN's allowed rate of return is set out in attachment 3.

5.3 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.[44] 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. 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 NER, is via the revenue granted to a service provider to cover its expected tax liability. Specifically, the NER requires 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'). This form of adjustment recognises that it is the payment of corporate tax which is the source of the imputation credit return to investors.

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

Consistent with AGN's proposal, our draft decision adopts a value of imputation credits of 0.4. We consider that a value for imputation credits of 0.4 will result in equity investors in the benchmark efficient entity receiving an ex ante total return (inclusive of the value of imputation credits) commensurate with the efficient equity financing costs of a benchmark efficient entity.

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 NER/NGR. This approach considers the value of imputation credits is a post-tax value before the impact of personal taxes and transaction costs.[45] As such, we view the value of imputation credits as the proportion of company tax returned to investors through the utilisation of imputation credits.[46]
- We consider our 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 NER/NGR.[47]
- 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'. Our definition of, and estimation approach for, these sub-parameters is set out in Table 5-5Table 5-8.

[45] Post-tax refers to after company tax and before personal tax.

[46] This means one dollar of claimed imputation credits has a post (company) tax value of one dollar to investors before personal taxes and personal transaction costs.

[47] 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.

Table 5-5 Gamma sub-parameters: definition and estimation approach

Sub-parameter	Definition	Estimation approach
Distribution rate (or payout ratio)	The proportion of imputation credits generated that is distributed to investors.	Primary reliance placed on the widely accepted cumulative payout ratio approach. Some regard is also given to Lally's estimate for listed equity from financial reports of the 20 largest listed firms.
Utilisation rate (or theta)	The utilisation value to investors in the market per dollar of imputation credits distributed.[48]	A range of approaches, with due regard to the merit of each approach: equity ownership approach tax statistics implied market value studies.

Source: AER analysis.

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.

In considering the evidence on the distribution and utilisation rates, we have broadly maintained the approach set out in the Rate of Return Guideline (the Guideline), but have re-examined the relevant evidence and estimates. This re-examination, and new evidence and advice considered since the Guideline, led us to depart from the 0.5 value of imputation credits we proposed in the Guideline.

Further detail on our draft decision in regards to the value of AGN's imputation credits is set out in attachment 4.

5.4 Regulatory depreciation (return of capital)

When determining the total revenue for AGN, we include an allowance for the depreciation of the projected capital base (otherwise referred to as 'return of capital').[49] Regulatory depreciation is used to model the nominal asset values over the 2018–22 access arrangement period and the depreciation allowance in the total revenue requirement.[50]

Our draft decision on AGN's regulatory depreciation allowance is $238.9 million ($ nominal) in total for the 2018–22 access arrangement period as set out in Table 5-6.

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[48] In this decision we use the terms theta, utilisation value and utilisation rate interchangeably to mean the same thing.

[49] NGR, r. 76(b).

[50] Regulatory depreciation allowance is the net total of the straight-line depreciation (negative) and the annual inflation indexation (positive) on the projected capital base.

Table 5-6 AER's draft decision on AGN's regulatory depreciation allowance for the 2018–22 access arrangement period ($ million, nominal)

	2018	2019	2020	2021	2022	Total
Straight-line depreciation	79.5	87.4	98.4	92.0	98.3	455.6
Less: indexation on capital base	39.3	41.2	43.5	45.5	47.2	216.7
Regulatory depreciation	**40.3**	**46.2**	**54.9**	**46.5**	**51.1**	**238.9**

Source: AER analysis.

We approve AGN's proposal to use the real straight-line method to calculate the regulatory depreciation allowance. However, the depreciation allowance in this draft decision is slightly higher than the allowance of $234.8 million ($ nominal) in AGN's proposal. This is mainly because of corrections to the application of the year-by-year tracking approach and our draft decisions on other components of AGN's proposal which impact on the regulatory depreciation allowance. These include our amendments to the opening capital base and AGN's forecast capex modelling.

We accept the standard asset lives proposed by AGN, which are consistent with the approved standard asset lives for the 2013–18 access arrangement period. They are also broadly comparable with the standard asset lives approved in our recent determinations for other gas service providers.[51] We also accept AGN's proposal to accelerate depreciation of mains and services that will be replaced over the 2018–22 access arrangement period.

Our draft decision approves AGN's proposal to move from its current approach to depreciation to an individual tracking approach.[52] AGN's new approach (also referred to as the 'year on year' approach) meets the criteria of having the depreciation schedule reflect the asset's economic life, where it tracks the asset's technical life. However, we also assessed the approach against the other criteria in the NGR, in particular whether the approach leads to efficient development in the market for reference services. Under this criterion we considered the impact of the change in the long run and any significant disruption in the short to medium term from a change in previous practice. The proposed change to year by year tracking does increase depreciation over short to medium term. Other things being equal, this also increases

[51] For example, *AER: Access arrangement final decision APA GasNet Australia (Operations) Pty Ltd 2013–17 Part 2: Attachments,* March 2013, p. 149*;* AER: *Final decision Amadeus Gas Pipeline access arrangement attachment 5 — Regulatory depreciation,* May 2016, p. 9.

[52] We note that the capex determined in this draft decision for 2016 and 2017 are estimates. As part of the final decision, we expect the estimate of capex for 2016 to be replaced by actuals and the estimate of capex for 2017 may be revised based on more up to date information by AGN in its revised proposal. The capex values are used to calculate the weighted average remaining asset lives. Therefore, we may recalculate AGN's remaining asset lives using the method approved in this draft decision to reflect revisions to the 2016 and 2017 capex values for the final decision.

prices. CCP11 raised this potential impact as a concern in its submission.[53] However, our analysis suggests the impact in this case to be modest and therefore unlikely to have a significant impact on the efficient growth in the market for AGN's reference services.

5.5 Capital expenditure (capex)

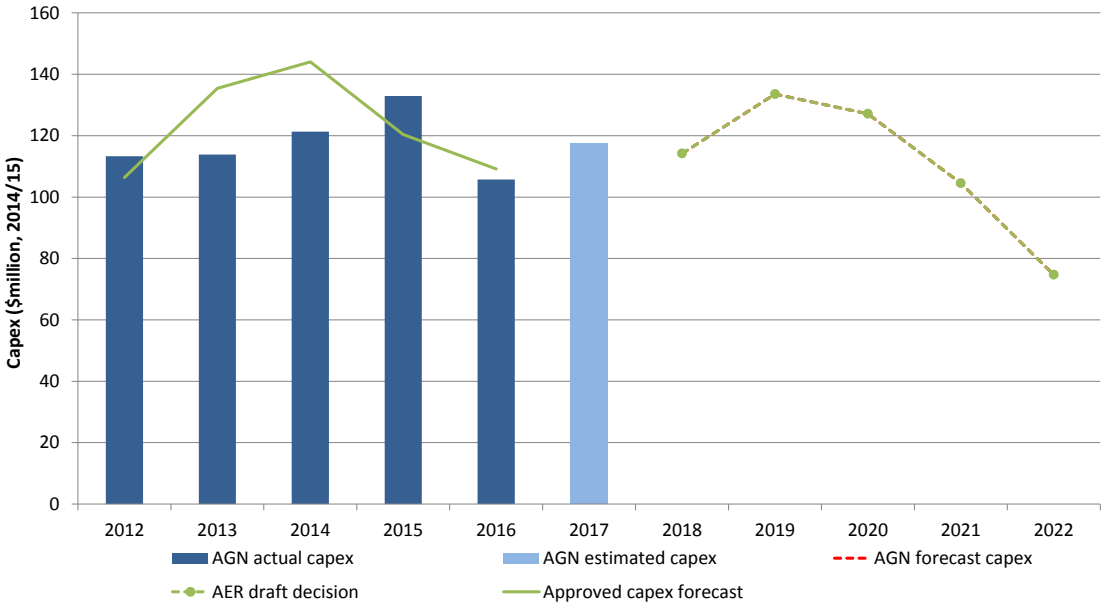
Capital expenditure (capex) refers to the capital costs and expenditure incurred in the provision of pipeline services.[54] This investment mostly relates to assets with long lives and these costs are recovered over several access arrangement periods. AGN recovers the costs of these assets through the return on capital and depreciation building blocks that form part of its total revenue. In this way AGN recovers the financing cost and depreciation associated with these assets over the expected life of these assets.

Our draft decision includes an assessment of AGN's actual capex in the current period, which forms part of its opening capital base.[55] It also includes an assessment of AGN's forecast capex for the 2018–22 access arrangement period, which forms part of its projected capital base.[56]

Figure 5-2 compares AGN's past and proposed forecast capex, and the forecasts we have approved in our previous decision for 2013–17 and this draft decision for 2018–22.

[53] CCP11, *Submission on AGN, AusNet and Multinet proposals*, 3 March 2017, p.53.
[54] NGR, r. 69.
[55] NGR, r. 77.
[56] NGR, r. 78(b)

Figure 5-2 AER draft decision compared to AGN's past and proposed capex ($ million, 2017)



Source: AER analysis.

5.5.1 Conforming capex for the current period

AGN's actual and expected capex of $591.3 million ($2017) over the current (2013 to 2017) period is approximately $9.2 million (or 1.5 per cent) below our approved forecast of $600.5 million ($2017) for that period.[57]

As part of this draft decision, we have reviewed AGN's capex for the first four years of the current period (2013 to 2016), for which actual data is available. Our review also covered AGN's actual capex in 2012 (the final year of the previous access arrangement period), for which actual data was not available at the time of our final decision on the 2013–17 access arrangements.[58]

Our draft decision is that AGN's actual capex of $587.1 million ($2017) for the years 2012 to 2016 is appropriately included in the opening capital base from 1 January 2018. We will review AGN's actual capex for 2017 as part of our next review of its access arrangement in 2022.

5.5.2 Conforming capex for 2018-22

We have also approved AGN's proposed forecast capex of $554.1 million ($2017) for 2018–22. This forecast is 6.7 per cent (or $37.2 million) lower than AGN's actual

[57] AER - *Access arrangement final decision - Envestra - Part 1* - March 2013

[58] AER - *Access arrangement final decision - Envestra - Part 1* - March 2013

expenditure in the current period. Key drivers of gross capex in the 2018–22 access arrangement period are forecast to be:

- Growth assets (31%) - Our approved forecast includes $174.3 million ($2017) for connections to the network. This is a reduction of 14.4 per cent from the current period. Growth in residential net connections is expected to fall marginally (1.97 per cent in 2018–22 compared to 2.04 per cent in 2013–17), as AGN does not expect any expansion of the network into new (greenfield) areas in the 2018–22 period.
- Mains replacement (26%) – AGN plans to complete its mains replacement program by the end of the 2018–22 access arrangement period. Our approved forecast allows for $147.3 million ($2017) of capex to replace 297km of mains over 2018–22, including replacement of mains in the Melbourne CBD. This is significantly less than the 696 km replaced in the current period, and the primary reason that AGN's total capex is expected to fall in 2018–22 as compared to the current period.
- IT (11%) - AGN proposed $63.5 million in IT capex for its Victorian and Albury networks. This is significantly higher than the $23.0 million it spent in the current access arrangement period, to accommodate AGN's nationalisation of its IT capabilities (a program we also considered and approved last year in our final decision on AGN’s access arrangement for its South Australian distribution network.)

Table 5-7 shows the capex approved in this draft decision for AGN's current (2013–17) and forecast (2018–22) access arrangement periods.

Table 5-7 AER approved capex by category for 2013–17 and 2018–22 ($ million, 2017)

Category	2013–17	2018–22	Difference between periods ($ millions)
Growth assets	203.7	174.3	-29.4
Mains replacement	255.9	147.3	-108.6
Meter replacement	28.8	32.6	3.8
Augmentation	20.5	34.2	13.7
Telemetry	1.8	1.2	-0.6
Other Assets	16.5	34.8	18.2
IT	23.0	63.5	40.5
Escalation	-	8.9	-
Overheads	41.0	57.3	16.3
GROSS TOTAL CAPITAL EXPENDITURE	**606.7**	**561.0**	**-45.7**
Contributions	15.4	6.8	-8.5
NET TOTAL CAPITAL EXPENDITURE	**591.3**	**554.1**	**-37.2**

Source: AER analysis.

Note: Direct costs in the 2013–17 period include related party expenditure.

5.6 Operating expenditure (opex)

Operating expenditure (opex) is the operating, maintenance and other non-capital expenses, incurred in the provision of reference services for a pipeline. Forecast opex is one of the building blocks we use to determine a service provider's total revenue requirement.

Our draft decision is to accept AGN's opex forecast $344.0 million ($2017) for the 2018–22 access arrangement period.[59] AGN's proposed total opex and our draft decision on opex are outlined in Table 5-8.

[59] Includes ancillary reference services and debt raising costs.

Table 5-8 AER's draft decision on total opex ($ million, 2017)

	2018	2019	2020	2021	2022	Total
AGN's proposal and AER draft decision	67.2	67.9	68.7	69.6	70.6	344.0

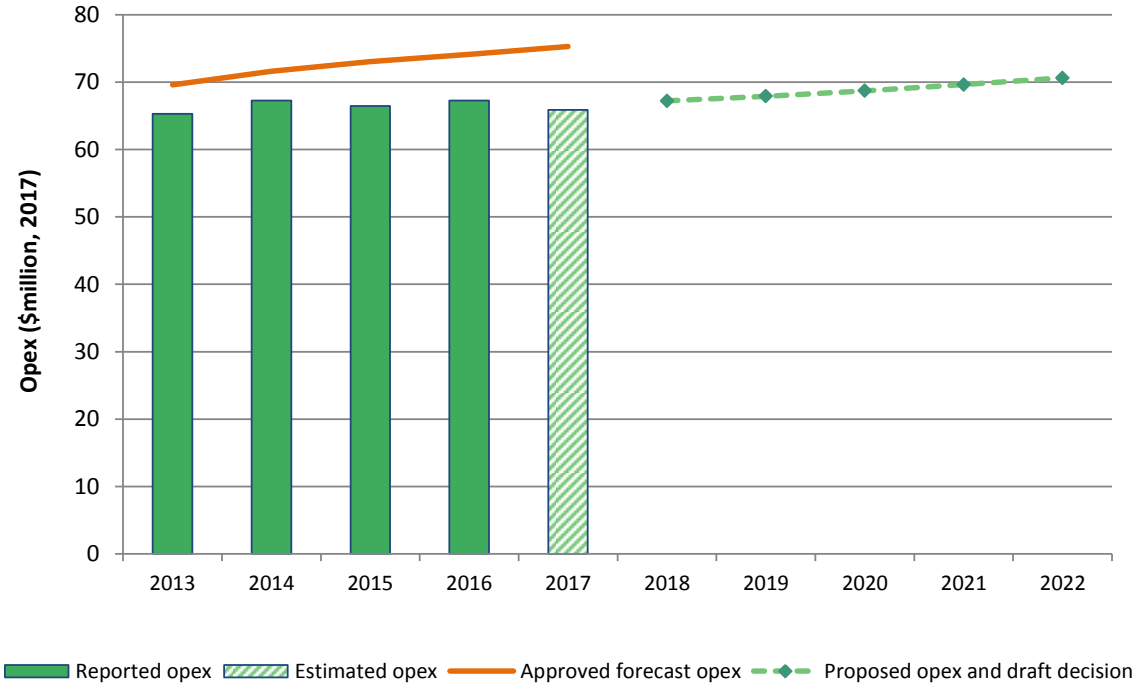
Source: AGN, *Access arrangement 2018–22 proposal, Attachment 1.9 - Victoria and Albury Post Tax Revenue Model*, December 2016; AER analysis.

Note: Includes debt raising costs. Numbers may not add up due to rounding.

Our approved opex forecast for 2018–22 is in line with AGN's expenditure in the current period. AGN's expenditure in the current (2013–17) period is around 9 per cent lower than the forecast we approved in our 2013–17 decision.[60] AGN attributed this reduction to efficiencies flowing from its change in ownership in 2014 and reductions in the unit costs for work delivered. This is partly offset in the forecast for 2018–22 by expected growth in customer numbers and changes in input prices over time. Figure 5-3 compares the opex forecast approved in this draft decision to the forecast we approved for 2013–17 and AGN's actual opex in that period.

[60] Expenditure in the current period is based on reported expenditure in 2013-16 and estimated expenditure in 2017.

Figure 5-3 AGN's proposal and AER's draft decision compared to actual opex in the current period ($ million, 2017)



Source: AGN, *Access arrangement 2018–22 proposal, Attachment 1.9 - Victoria and Albury Post Tax Revenue Model*, December 2016; AER analysis.

Note: Includes debt raising costs.

AGN's proposal, and our draft decision, is based on an estimate of AGN's opex in its 2016 base year. This will be updated in AGN's revised proposal and our final decision for actual opex in that year.

5.7 Efficiency carryover mechanism

The opex efficiency carryover mechanism in AGN's access arrangement provides an additional incentive for AGN to pursue efficiency improvements in its opex over an access arrangement period. It does this by allowing AGN to retain efficiency savings achieved within a particular period for a longer period of time.

Our draft decision is to approve positive carryover amounts of $18.1 million ($2017) for AGN's Victorian network and $1.0 million for its Albury network, from the application of their efficiency carryover mechanisms in the 2013–17 access arrangement period. AGN's proposal was based on an estimate of its opex for 2016, which we have updated with actual opex. As a result, the carryover amount approved in this draft decision is $7.0 million less than AGN proposed for its Victorian network and $0.4 million less than it proposed for its Albury network.

Table 5-9 shows our draft decisions on the proposed carryover amounts.

Table 5-9 AER draft decision on carryover amounts ($ million, $2017)

	2017	2018	2019	2020	2021	Total
AGN proposed carryover - Victoria	14.8	6.4	4.4	-0.4	–	25.1
Draft decision	11.6	5.1	3.1	-1.8	–	18.1
Difference	**-3.1**	**-1.2**	**-1.3**	**-1.3**	**–**	**-7.0**
AGN proposed carryover - Albury	1.3	0.1	0.2	-0.1	–	1.4
Draft decision	1.3	0.0	0.0	-0.3	–	1.0
Difference	**0.1**	**-0.1**	**-0.2**	**-0.2**	**–**	**-0.4**

Source: AER analysis.

Note: Numbers may not add up due to rounding.

We accept AGN's proposal to retain an efficiency carryover mechanism for the 2018–22 access arrangement period, which will reflect the combined opex forecast for the two pipelines. However, we have amended AGN's proposed efficiency carryover mechanism to reflect improvements included in the efficiency benefit sharing scheme we released in November 2013 for electricity service providers.[61] Importantly, the amendments will give AGN more flexibility in the choice of base year it uses to forecast opex in the following period. We have also reduced the number of cost categories we will exclude from the mechanism.

The total opex forecasts we use to calculate efficiency gains and losses for the 2018–22 access arrangement period are set out in table 9.3 of attachment 9.

5.8 Corporate income tax

AGN has adopted the post-tax framework to derive its revenue requirement for the 2018–22 access arrangement period.[62] Under the post-tax framework, a separate corporate income tax allowance is calculated as part of the building blocks assessment.

Table 5-10 sets out our draft decision on the estimated cost of corporate income tax allowance for AGN.

[61] AER, *Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013, pp. 7–9.

[62] AGN, *Access arrangement information*, December 2016, pp. 143–148

Table 5-10 AER's draft decision on corporate income tax allowance for AGN ($ million, nominal)

	2018	2019	2020	2021	2022	Total
Tax payable	21.2	21.7	22.1	16.7	18.1	99.8
Less: value of imputation credits	8.5	8.7	8.9	6.7	7.2	39.9
Net corporate income tax allowance	**12.7**	**13.0**	**13.3**	**10.0**	**10.8**	**59.9**

Source: AER analysis.

We accept AGN's proposed approach to calculating its forecast corporate income tax allowance. AGN's proposed approach is consistent with the AER's post-tax revenue model (PTRM) for electricity service providers and the approach previously approved in gas access arrangement decisions. Our draft decision on AGN's corporate income tax allowance over the 2018–22 access arrangement period is $59.9 million ($ nominal). This represents an increase of $2.7 million or 4.7 per cent compared to the forecast corporate income tax allowance of $57.2 million in AGN's proposal.

Our draft decision reflects amendments to AGN's proposed inputs for forecasting the cost of corporate income tax including the opening tax asset base, standard tax asset lives and the remaining tax asset lives. Our adjustments to other building block costs, including our updates to the rate of return calculation and AGN's modelling of the capital base roll-forward and depreciation, also affect revenues and in turn impact the tax calculation.[63]

[63] Changes to other building block costs affect revenues, which also impact the tax calculation.

6 New incentive schemes to apply from 2018

AGN proposed two new incentive schemes to apply for the 2018-22 access arrangement period: a capital expenditure sharing scheme (CESS) and a network innovation scheme (NIS).

Our draft decision accepts the introduction of a CESS, to encourage appropriate and efficient investment in the network and provide continuous incentives to seek efficiencies throughout the access arrangement period. We consider a CESS could lead to benefits for consumers, particularly in limiting the growth of the capital base by providing a greater incentive for AGN to incur only efficient capex.

The CESS that will be included in AGN's access arrangement is based on the CESS we developed under the National Electricity Rules (NER).[64] We are conscious of the risk that increased incentives could lead to inefficient deferral of capex in the interests of reducing costs within an access arrangement period. Recognising that there is no balancing service quality scheme like the STPIS under the (NER), any reward to AGN under the CESS will be contingent on AGN maintaining current service standards, measured through a new network health index. If service standards decline, then AGN will receive a reduced CESS reward or no reward at all.

Our draft decision does not accept the introduction of a NIS, which AGN proposed to fund small scale operational expenditure targeted at managing peak demand on the network instead of investing in network augmentation. Under the proposed NIS, AGN would apply to the AER for projects that satisfy pre-determined criteria, with a notional budget of $1 million per year (and room to increase that budget on application). We consider that, particularly with the addition of a CESS, the current framework provides sufficient opportunity to invest in innovation while allowing businesses to retain efficiency benefits.

[64] AER, *Capital expenditure incentive guideline for electricity network service providers* - November 2013

7 Non-tariff components

The non-tariff components of an access arrangement include:

- the terms and conditions for the supply of reference services
- extension and expansion requirements—the method for determining whether an extension or expansion is a part of the covered pipeline and the effect this will have on tariffs
- capacity trading requirements—the arrangements for users to assign contracted capacity and change delivery and receipt points
- provisions for receipt and delivery point changes, and
- a review submission date and a revision commencement date.[65]

Our draft decision accepts AGN's proposed access arrangement provisions relating to capacity trading, receipt and delivery point changes and review submissions/revision commencement dates without amendment.

In attachment 12 of this draft decision we set out minor amendments to AGN's proposed terms and conditions of supply in response to stakeholder submissions, subject to which we accept AGN's proposal. We also accept AGN's extensions and expansions requirements subject to minor amendments to further align it with the requirements that will apply to other Victorian gas distributors.

[65] Although not required in the present case, all transmission pipelines and some distribution pipelines are also required to set out how any spare or developable capacity will be allocated among prospective users ('queuing requirements' - see NGR r. 103.

8 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.[66]

Energy Ministers have provided us with a substantial body of explanatory material that guides our understanding of the NGO.[67] 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.[68]

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.[69] 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 draft decision has 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.

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.[70] At the same time, however, there are a range of outcomes that are unlikely to advance the NGO, or not 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.[71] 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 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

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66 NGL, s. 23.

67 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.

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

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

70 *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.

71 NGL, s. 24(7).

network[72] and could have adverse consequences for safety, security and reliability of the network.

The NGL also includes the revenue and pricing principles (RPP), which support the NGO.[73] As the NGL requires,[74] we have taken the RPPs into account throughout our analysis under the NGR. 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.
>
> 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.

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72 NGL, s. 24(6).
73 NGL, s. 24.
74 NGL, s. 28(2).

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.[75] 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 capex attachment 6 and opex attachment 7).
- We take into account the economic costs and risks of the potential for under and over investment by a service provider in our assessment of AGN's forecast capex and opex proposals (refer to capex attachment 6 and opex attachment 7).
- We consider the economic costs and risks of the potential for under and over utilisation of AGN's network in our decisions on demand forecasting and forecast augmentation capex (refer to capex attachment 6 and demand attachment 13).
- The opex and capex efficiency carryover mechanisms in this decision provide 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 efficiency carryover mechanism attachment 9; other incentives schemes attachment 14).
- We have determined AGN's opening capital base taking into account the capital adopted in the previous access arrangement (refer to capital base attachment 2).
- The allowed rate of return objective reflects the revenue and pricing principle in s. 24(5). 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 rate of return attachment 3).
- Our financing determinations provide AGN with a reasonable opportunity to recover at least the efficient costs of accessing debt and capital (refer to rate of return attachment 3).

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 results in higher revenue than another option. 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+
- 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 recognition that for the long term interests of consumers, the

[75] 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.

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.[76] 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.

8.1 Achieving the NGO to the greatest degree

An access arrangement decision is complex. 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. There may be more than one plausible forecast. There is substantial debate amongst stakeholders about the costs we must forecast, supported by expert opinion. As a result, for certain components of our decision there may be several plausible answers or several plausible point estimates.

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.[77]

In reaching this draft decision we have considered AGN's proposal and examined each of the building block components of the forecast revenue requirement, 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 draft decision. We have had regard to and weighed up all of the information assembled before us in making this draft decision, and have made as much of this information publicly available as practicable for the purposes of consultation.

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

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

Therefore, we are satisfied that among the options before us, our draft decision on AGN's access arrangement for the 2018–22 access arrangement period contributes to achieving the NGO to the greatest degree.

8.1.1 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.[78] 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 the forecasts of 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 supporting 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).
- 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 draft decision. These considerations are explored in the relevant attachments.

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

9 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 submissions on AGN's proposal
- held a public forum on AGN's proposal
- published this draft decision and reasoning
- invited written submissions on this draft decision.

We have also consulted on our approaches to these reviews: our 2013 Better Regulation Program brought a wide range of views to our development of assessment tools and techniques and our approaches to decision making. More recently, we have commenced consultation on approaches to forecasting inflation for the purposes of modelling regulated revenues. Our continued engagement on these enables us to identify and reflect stakeholder priorities and will result in decisions that will or are likely to contribute to the achievement of the NGO to the greatest degree.

9.1 AGN's engagement with customers

AGN undertook its own engagement process in the development of its proposal, notably including public consultation on a 'draft plan' some six months prior to submission: a first for engagement on a regulatory proposal submitted to the AER. Further consultation material used by AGN was provided to us as supporting documents to AGN's proposal, together with an overview of its engagement strategy and outcomes.[79] In addition to consultation on its proposal, AGN also consulted jointly with other Victorian gas distributors on incentive arrangements for gas distributors to inform its proposals for the CESS and NIS.[80]

It is clear from submissions—which were overwhelmingly in support of the proposal AGN ultimately submitted—that these efforts were both valued and productive. Key comments included:

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[79] AGN - *Final Plan - Access Arrangement Information for our Victorian and Albury natural gas distribution networks 2018-2022* - 20161222, Chapter 5, pp. 31-55; See also Attachments 5.1-5.12 and 15.1 to AGN's proposal.

[80] AGN - *Final Plan - Access Arrangement Information for our Victorian and Albury natural gas distribution networks 2018-2022* - 20161222, Chapter 11, pp. 127-130; See also Attachments 11.1-11.6 to AGN's proposal.

> …one of the first regulatory proposals to seriously demonstrate consumer focussed engagement that has been subsequently implemented into the final proposal… a 'no shocks' regulatory proposal, an approach and attitude that we hope sets the approach for future network business regulatory proposals.[81]
>
> …a comprehensive process that ensured all stakeholders were clear around the principles used by AGN in making its Access Arrangement decisions. It was highly informative and answered many queries …regarding the economic basis for its regulatory proposal[82]
>
> …a robust stakeholder engagement program which demonstrates [AGN's] commitment to making genuine efforts to effectively engage with customers and to increase stakeholder transparency in the development of access arrangement proposals.[83]AGN [and AusNet] appear to have consulted extensively with industry peers and consumers on the design of the proposed incentive mechanisms. In particular they have sought feedback on the proposed CESS to ensure that it is fit for purpose, delivers benefits to customers and would not compromise the quality of services.[84]

Submissions also highlighted the benefits that AGN's engagement delivered for the business, including that:

- comments in submissions were unlikely to come as a shock to them.[85]
- AGN's engagement provided stakeholders with a clear sense "that [AGN] knows who they are and where they are heading", which was not only instructive but built confidence that AGN's proposal was "much more genuine than ambit".[86]

We tasked the AER Consumer Challenge Panel (CCP11) specifically with advising the AER on the effectiveness of AGN's engagement activities with its customers and how this was reflected in the development of its proposal.

CCP11's advice to us was that AGN has clearly met its objective of presenting an access arrangement proposal which is underpinned by effective stakeholder engagement.[87] CCP11 consulted with a range of consumer representatives who had interacted with AGN in the development of its proposal and found responses very

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81 Uniting Communities - *No Shocks AA Proposal: Submission to the AER regarding the AGN access arrangement proposal for Victoria Albury* - 19 April 2017, p. 2.

82 AGL Energy Limited - *Victorian gas access arrangement proposals* - 31 March 2017, p. 3.

83 Energy Networks Australia - *Australian Gas Networks (Victoria and Albury) Access Arrangement Proposal 2018-22 – Energy Networks Australia's comments* - 3 March 2017, p. 2.

84 ATCO Gas Australia - *Submission to Victorian Gas Networks (AGN and AusNet Services) Access Arrangement 2018-22* - 3 March 2017, p. 2.

85 Uniting Communities - *No Shocks AA Proposal: Submission to the AER regarding the AGN access arrangement proposal for Victoria Albury* - 19 April 2017, p. 2.

86 Uniting Communities - *No Shocks AA Proposal: Submission to the AER regarding the AGN access arrangement proposal for Victoria Albury* - 19 April 2017, pp.2-3.

87 Consumer Challenge Panel (CCP 11) - *Response to proposals from AGN, AusNet and Multinet for the 2018-2022 Access Arrangements* - 3 March 2017, pp. 18-22, p. 5.

positive. Common themes were the clear support for these activities from AGN's management and CEO, [88] and praise for AGN's initiative in releasing a draft of its proposal prior to submission: one that CCP11 agreed represented a significant step forward in AGN's approach to stakeholder engagement.[89] The care taken by AGN in its proposal to clearly set out, in each section of the proposal, how stakeholders had been engaged on that topic and how it informed AGN's approach was another initiative welcomed by CCP11.[90]

CCP11's advice identified a number of specific areas in which it suggests AGN could further improve its engagement, which we encourage AGN to look to in future processes. That advice[91] is available on our website for the benefit of other businesses as well as AGN. Its conclusion, though, was that AGN has now established a solid foundation and track record for effective stakeholder engagement.[92]

CCP11 identified AGN's clear commitments to the public as a strength of AGN's proposal and regarded it as a 'best practice current Australian energy network regulatory process'.[93] Like others, CCP11 has identified the next challenge for AGN as considering opportunities to engage with stakeholders at the 'involve' and 'collaborate' levels of the IAP2 Public Participation Spectrum, particularly focussing on the 'Promise to the Public' dimension of the spectrum.[94]

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88 Consumer Challenge Panel (CCP 11) - *Response to proposals from AGN, AusNet and Multinet for the 2018-2022 Access Arrangements* - 3 March 2017, pp. 18-22, p. 17.

89 Consumer Challenge Panel (CCP 11) - *Response to proposals from AGN, AusNet and Multinet for the 2018-2022 Access Arrangements* - 3 March 2017, p. 21.

90 Consumer Challenge Panel (CCP 11) - *Response to proposals from AGN, AusNet and Multinet for the 2018-2022 Access Arrangements* - 3 March 2017, p. 22.

91 Consumer Challenge Panel (CCP 11) - *Response to proposals from AGN, AusNet and Multinet for the 2018-2022 Access Arrangements* - 3 March 2017, pp. 18-22.

92 Consumer Challenge Panel (CCP 11) - *Response to proposals from AGN, AusNet and Multinet for the 2018-2022 Access Arrangements* - 3 March 2017, p. 22.

93 Uniting Communities - *No Shocks AA Proposal: Submission to the AER regarding the AGN access arrangement proposal for Victoria Albury* - 19 April 2017, p. 5.

94 Consumer Challenge Panel (CCP 11) - *Response to proposals from AGN, AusNet and Multinet for the 2018-2022 Access Arrangements* - 3 March 2017, p. 22.

A List of submissions

This draft decision has been made with regard to submissions from the following stakeholders on AGN's proposal:

Submission from:	Date received*
Jemena Gas Networks	2 March 2017
ATCO Gas Australia	3 March 2017
Consumer Challenge Panel (CCP11)	3 March 2017
Energy Networks Australia	3 March 2017
Red Energy and Lumo Energy	6 March 2017
Origin Energy	10 March 2017
AGL Energy Limited	21 March 2017
Beverly Hughson	22 March 2017
Uniting Communities	19 April 2017

* This column lists the date on which submissions were *received* by the AER, which may differ from the date on the submission itself.