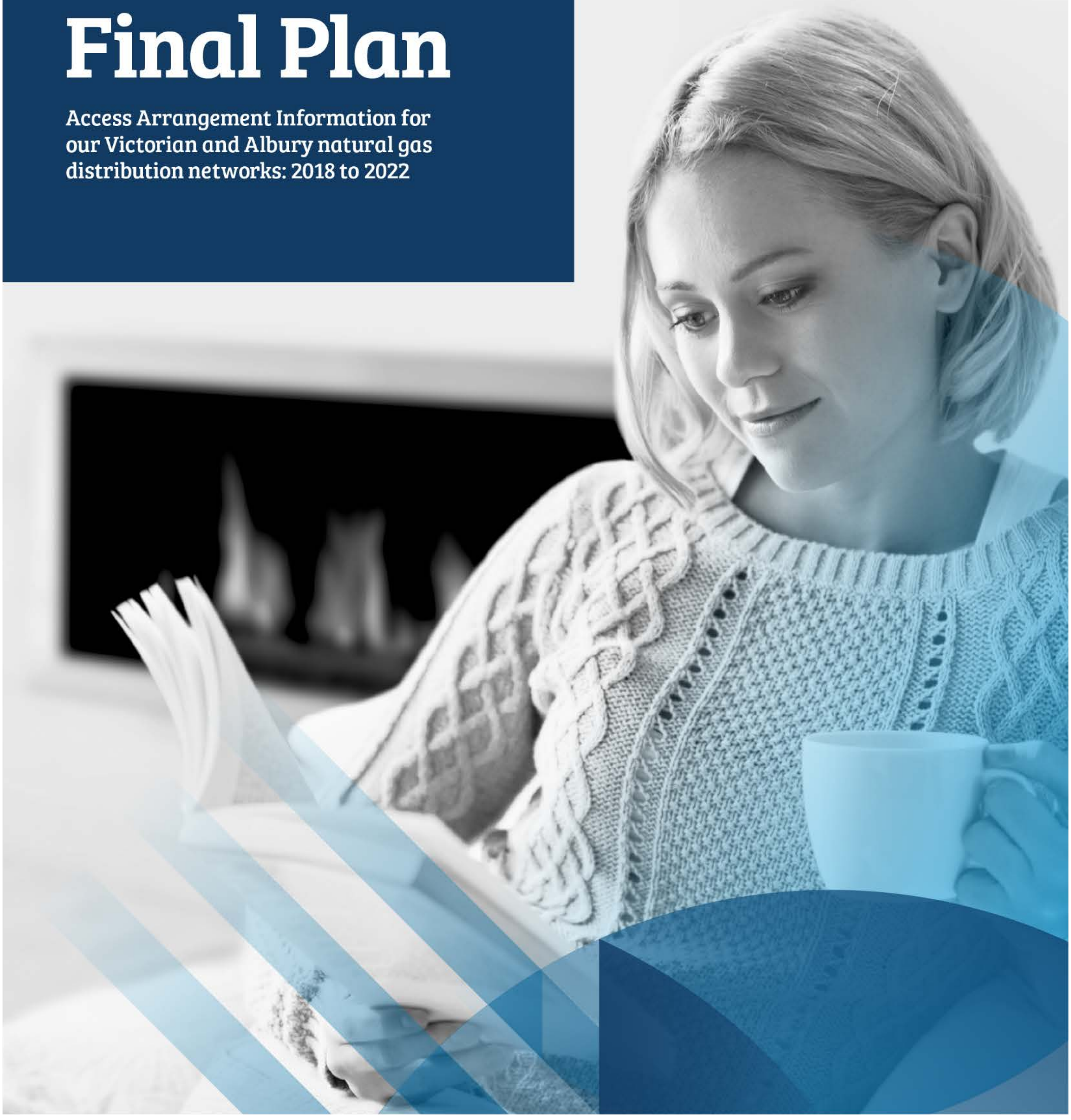
December 2016

Final Plan

Access Arrangement Information for our Victorian and Albury natural gas distribution networks: 2018 to 2022



We are Australian Gas Networks, one of Australia's largest natural gas distribution companies.

Our Vision is to become the leading gas distributor in Australia. We will achieve this by delivering for our customers, being a good employer and being sustainably cost-efficient.

Foreword from the CEO

I am delighted to present our Final Plan for our natural gas distribution networks in Victoria and Albury for the five-year period commencing 1 January 2018. Our plan delivers continuous improvement on our already high service levels, an 11% upfront cut in distribution prices (before inflation), reduced total expenditure, and lower financing costs in line with recent decisions by the Australian Energy Regulator (AER).

Australian Gas Networks Limited is one of Australia's largest natural gas distribution companies, serving around 1.2 million customers across most Australian states and territories. In Victoria and Albury we deliver natural gas to around 650,000 customers across central and northern Melbourne, north to Shepparton, Wodonga and Albury in New South Wales, east to Warragul, Traralgon and Bairnsdale and south east to the Mornington Peninsula.

We have delivered strong performance for our Victorian and Albury customers over the 2013 to 2017 period, and importantly, we have met our leak management targets. We have connected over 16,000 new customers to natural gas each year and are on track to deliver 100% (or 696 kilometres) of our mains replacement program.

We intend to improve on our strong safety performance over the 2018 to 2022 period. We are proposing to replace a further 297 kilometres of old mains, which includes 25 kilometres of mains in the centre of Melbourne. This will complete the replacement of old mains in the Victorian networks. This program is the key driver for ensuring ongoing public safety and network reliability.

Our networks cover some of the fastest growing areas in Australia and we are proud to support this growth. Over the 2018 to 2022 period, we expect to connect around 16,000 new customers to natural gas each year. Customer growth spreads the benefits of gas and lowers prices to existing customers by spreading our mostly fixed costs over a larger customer base.

We are very conscious that the cost of living, including utility bills, is a major concern for our customers. Gas distribution prices make up around one third of the average domestic retail gas bill, so we have a role to play in the affordability challenge. I am therefore pleased to deliver an 11% upfront price cut (before inflation), with modest annual increases thereafter to match our growing capital base.

Natural gas remains a highly cost-effective and clean domestic fuel compared to electricity. In Victoria, most electricity is produced from coal, and using natural gas in the home saves around five tonnes of carbon dioxide per annum annually compared to mains electricity, meaning that gas is cleaner as well as cheaper than electricity.

Our plan is based on the considerable experience of AGN, our operating partner (APA Group) and the feedback we have received from our stakeholders, including our customers. A key part of enabling this feedback was the release of our Draft Plan in July 2016. We proactively sought and facilitated feedback on this Draft Plan and you will find details on how we've incorporated these views into our plans throughout this document.

I would like to take this opportunity to thank the staff of AGN, APA, our Reference Groups and those customers and stakeholders that have helped to develop and shape our proposal.

Overall, we are proposing to continuously improve our strong safety and customer service levels and cut distribution prices on 1 January 2018. We are confident that our plans for 2018 to 2022 are in the long-term interests of our Victorian and Albury customers.

Ben Wilson

Chief Executive Officer, Australian Gas Networks

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Our Vision is to be the leading natural gas distributor in Australia.

Lower prices

11% ↓

Cut in prices on 1 January 2018

Improved Service

>90%

Of emergency calls answered within 10 seconds.

100%

Mains replacement completed.

Continuous improvement in safety, reliability and customer service.

Lower Costs

$23m ↓

Cut in expenditure compared to actual expenditure incurred in the current Period.

>2.00% ↓

Finance cost down from 7.39% to less than 6%.

Ensuring we are sustainably cost-efficient.

New Customers

+80,000

New customers connecting to our networks over 2018 to 2022

5.4 t CO_2 ↓

Tonnes of CO_2 saved per new customer per annum.

Better access to gas, contributing to lower carbon emissions.

Lower prices, lower costs, continuous service improvements.

Plan Highlights

Australian Gas Networks Limited (AGN) is one of the largest natural gas distributors in Australia. We deliver natural gas to around 650,000 customers connected to our Victorian and Albury networks. We are required to update the prices we charge for providing natural gas distribution services every five years.

Our prices for the next (2018 to 2022) Access Arrangement (AA) period are set out in this Final Plan, which we are required to submit to the Australian Energy Regulator (AER) for approval by 3 January 2017. Our overarching objective is to submit a plan that delivers for customers, is underpinned by effective stakeholder engagement and is capable of being accepted by the AER.

Our Final Plan outlines the key activities and expenditure that we intend to undertake and the prices that we propose to charge over the next AA period. Our Final Plan also highlights the feedback that we have received from our customers and stakeholders, including our consideration of feedback received on the Draft Plan which we released for public consultation on 5 July 2016.

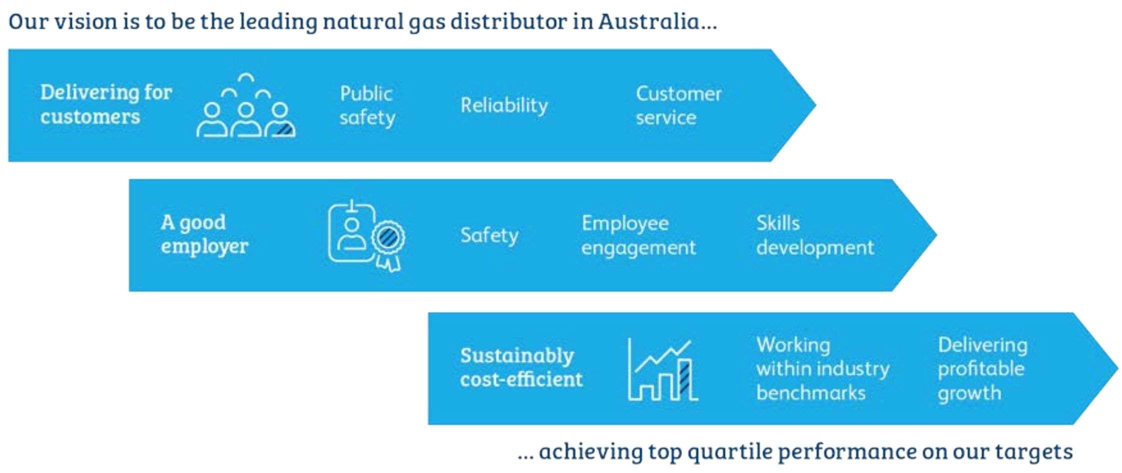
This section summarises what we have delivered over the current (2013 to 2017) AA period and what we propose to deliver over the next AA period, as measured against the key targets set out in our Vision.

Our Vision

Our aim is to be the leading natural gas distributor in Australia. Our definition of leading is to achieve top quartile performance compared to other Australian natural gas distributors across all of our key targets. Our Vision sets out the following three key objectives that we consider are consistent with being the leading natural gas distributor in Australia:

- *Delivering for Customers* – which means ensuring public safety and the provision of high levels of network reliability and customer service;
- *A Good Employer* – which means ensuring the safety of our employees (including contractors), ensuring employees are motivated to achieve our Vision and receive appropriate training; and
- *Sustainably Cost-Efficient* – which means undertaking the required work within the allowances set by the AER while growing the network in a prudent and efficient manner.

Figure 1: Our Vision Statement



Importantly, we can measure our performance against all the key targets set out in our Vision, which means we can assess our performance over the current AA period and measure our proposal over the next AA period against the key targets set out in our Vision.

What We Have Delivered

We have met the key safety standards set for the business and delivered the major outputs set by the AER for the current AA period.

Delivering for Customers

We have delivered natural gas to our customers in a safe manner and complied with all relevant safety obligations/requirements set for the business. Key achievements over the period include:

- providing a high level of public safety:
  - answering 92% of emergency calls within 10 seconds;
  - attending to 95% of all publicly reported leaks within two hours;
  - completed all routine natural gas leak surveys in the required time period;
  - planning to deliver the full low pressure mains replacement program approved by the AER for the current AA period (696 kilometres);
- providing high reliability of supply to our customers, averaging only 18 interruptions affecting five or more customers each year;
- delivering and implementing our customer satisfaction surveys, which for the first time provide the business with direct information to understand and improve our customer service;
- designing and implementing our broader stakeholder engagement program, which assists the business to ensure that we are promoting the long-term interests of our customers; and
- facilitating more than 16,000 new customer connections per annum.

A Good Employer

We have achieved industry best practice employee safety levels over the current AA period and provided all necessary training to our employees and contractors. Key achievements over the period include:

- ensuring the ongoing safety of our employees, with only 1.6 Lost Time Injuries (LTIs) per million hours worked;
- ensuring employees have access to the relevant training, with 100% compliance regarding employee refresher training; and
- implementing an employee engagement survey, which results showed a strong level (over 70%) of overall engagement.

Sustainably Cost Efficient

We have achieved leading productivity performance relative to other gas distributors operating in Australia. Key achievements over the period include:

- overall productivity levels around 10% higher than the next most efficient distributor and 13% above the industry average;
- spending within the expenditure allowance set by the AER, generating savings for customers in the next AA period; and
- delivering major network extensions to Merrifield, Koo Wee Rup and Wandong-Heathcote Junction as approved by the AER.

What We Will Deliver

We are proposing to continually build on this strong performance over the next AA period.

Delivering for Customers

We consider the safe and reliable supply of natural gas is the most important driver of business performance. We are also focused on providing high levels of customer service, particularly given natural gas is a fuel of choice for most customers. Over the next AA period we will:

- improve public safety through the completion of our mains replacement program;
- maintain reliability through several key network expansion initiatives that are aimed at facilitating the ongoing connection of customers to our networks;
- improve the security of supply across the networks, particularly by completing a long-term initiative in the outer eastern/southern parts of the network through to the Mornington Peninsula;
- maintain current levels of customer service, which is consistent with the feedback we received during our stakeholder engagement program; and
- continue to support network growth, with an average of 16,000 new customer connections to our networks each year (or almost 80,000 over the next AA period), which will assist in delivering lower prices to existing customers.

A Good Employer

Employee safety is a key focus of the business. Over the next AA period we are targeting:

- a reduction in the LTI frequency rate from 1.6 to less than 1.0 LTIs per million hours worked (with an ultimate goal of zero);
- continued monitoring and compliance with employee training standards; and
- ongoing improvements in employee engagement levels, which we measure on an annual basis.

Sustainably Cost Efficient

Being sustainably cost-efficient means delivering the required outputs within the industry allowances while growing the network in a prudent and efficient manner. Over the next AA period we are targeting:

- an upfront 11% reduction in distribution prices for Victoria and Albury (before inflation), with prices lower on average in real terms over the next AA period compared to current prices;

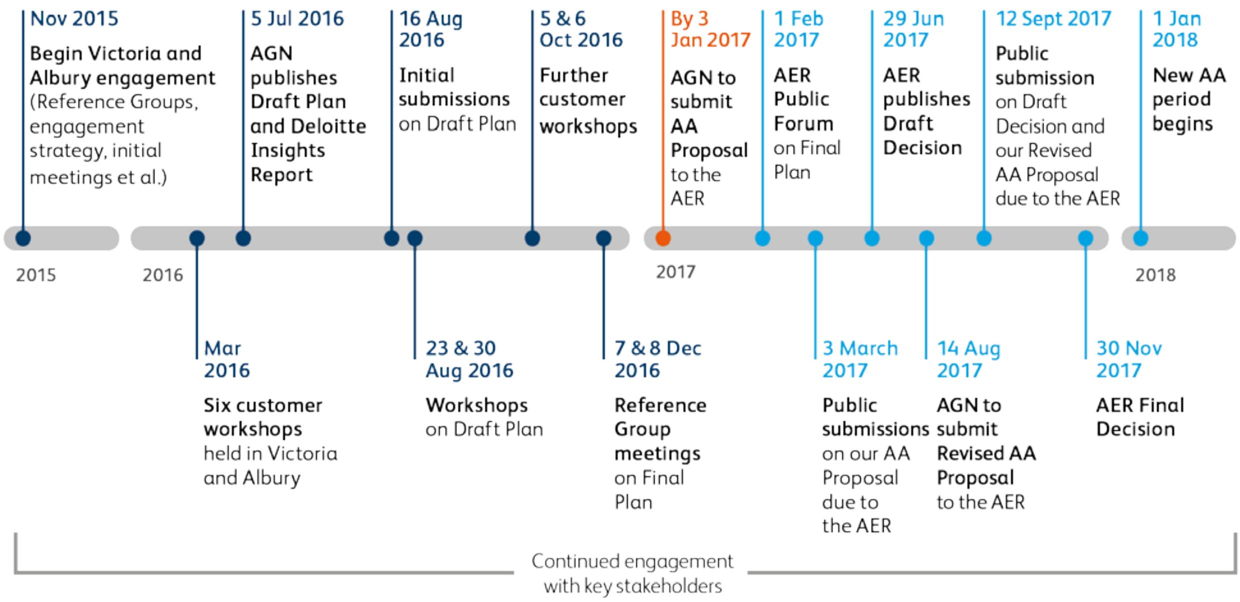
- the completion of our mains replacement program, which has the support of the safety regulator, Energy Safe Victoria;
- the continued delivery of leading productivity performance by lowering total expenditure levels by $23 million over the next AA period;
- continued support of network growth opportunities; and
- improving and strengthening the incentives for the business to pursue prudent and efficient expenditure whilst maintaining high levels of network safety, reliability and service.

Next Steps

We consider that effective stakeholder engagement is vital to achieving our objective of submitting a plan that delivers for our customers and is capable of being accepted by the AER. As already noted, we have implemented a comprehensive stakeholder engagement program in developing this Final Plan; in particular, through developing and engaging on our Draft Plan. The feedback received from stakeholders and what we have done in response is reported throughout this Final Plan.

We intend to engage with stakeholders on an ongoing basis, including during the AER review process. The AER will also seek stakeholder feedback during its own review process, including in response to an AER Draft Decision on our AA Proposal (expected August 2017). The key dates for the review of our AA Proposal are set out in Figure 2.

Figure 2: Historical and Future Key Milestones



We are also keen to continue to receive any feedback on our Plans directly from our stakeholders at any point in the future. Details on how you can provide your feedback are provided in Chapter 1 of this document.

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1. About this Plan

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1. About this Plan

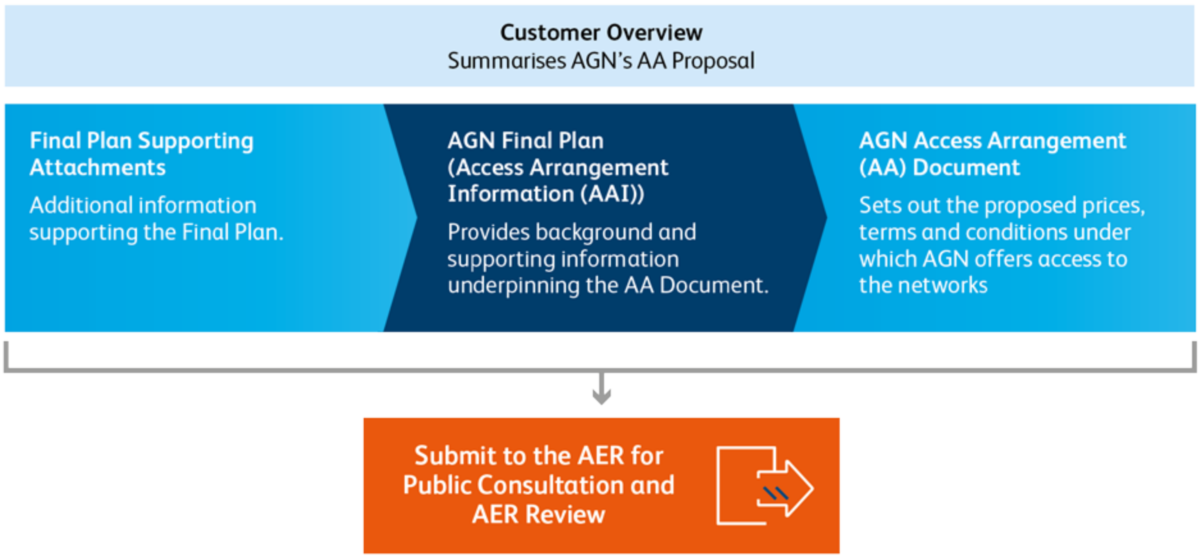
1.1. Introduction

This Final Plan (also known as our Plan and/or our Access Arrangement Information (AAI)) has been prepared by Australian Gas Networks Limited (AGN). The purpose of this Plan is to provide the necessary information to our stakeholders to understand the proposed revisions to the Access Arrangement (AA) that applies in respect of our Victorian and Albury natural gas distribution networks (the networks).[1] The AA sets out the price and non-price terms and conditions governing access to the networks.

The revised AA is to apply for the five-year period commencing 1 January 2018 (referred to as the next AA period). This Plan, the supporting attachments to the Plan and the revised AA itself are collectively referred to as our AA Proposal. Pursuant to the relevant regulatory framework, we are required to submit our AA Proposal to the Australian Energy Regulator (AER) by 3 January 2017 for its review (see Figure 1.1).

This chapter provides an overview of the networks and the relevant regulatory framework governing the development of our AA Proposal. This chapter also discusses the process we followed to prepare our AA Proposal, the structure of the Plan and further opportunities for stakeholders to provide input into the development and finalisation of the AA that is to apply over the next AA period.

Figure 1.1: Our Access Arrangement Proposal



During the current (2013 to 2017) AA period, AGN has been providing services to customers in our Victorian and Albury networks under two separate AAs. Both AAs offer access seekers the

[1] National Gas Rule 72 sets out the compliance requirements of this our Final Plan. Further detail on the relevant regulatory framework and the compliance of this AA Proposal is provided in Attachment 1.1 to this Final Plan.

same services and terms and conditions and both were due for revision at the same time (submission date of 3 January 2017).

In November 2015, after engaging with our customers and stakeholders, we applied to the AER to consolidate the AAs with a view to reducing administrative costs and improving future stakeholder engagement. The AER approved our application to consolidate the Victorian and Albury AAs into a single AA Proposal, and consistent with our suggested approach to consolidation, required:[2]

- that a separate tariff zone be maintained for Albury (see Chapter 14);
- that separate information for Albury and Victoria be provided in relation to:
  - past conforming capital expenditure (capex) (see Attachments 1.5 and 1.6);
  - carryover amounts under the operating expenditure (opex) efficiency carryover mechanisms (see Chapter 11);
  - actual opex for the current AA period (see Attachments 1.5 and 1.6); and
  - the information necessary to determine the opening capital base for Albury and Victoria (see Chapter 9).

We have satisfied all of the above conditions in preparing this consolidated AA Proposal for our Victorian and Albury networks.

1.2. Overview of the Networks

Our Victorian and Albury networks supply around 650,000 customers through around 11,000 kilometres of predominantly distribution mains. Our networks are located in the city of Melbourne, inner and outer northern suburbs of Melbourne, outer eastern and southern areas of Melbourne, surrounding regional areas and Albury. Further information on the networks is provided in Chapter 2.

1.3. Relevant Regulatory Framework

We operate our networks in accordance with the National Gas Law (NGL), National Gas Rules (NGR) and various state-based operating guidelines. The AER monitors our compliance with the NGL and NGR. The overarching requirement of the NGL is the National Gas Objective (NGO), which requires AGN 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"*.[3]

To achieve the NGO we must:

- ensure that prices are consistent with the lowest sustainable (long-term efficient) cost;
- deliver service levels that reflect what our customers want and are willing to pay for;
- provide services in a safe and reliable manner; and
- adapt prices and service levels to changing market conditions.

[2] Further information on AGN's application to consolidate AAs and the related decision by the AER is available on the AER's website: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/australian-gas-networks-victoria-and-albury-access-arrangement-2018-22/initiation.

[3] *National Gas (South Australia) Act 2008, s23*.

Further information on the overarching regulatory framework, including key principles and the requirements of an AA Proposal are provided in Attachment 1.1.

1.4. Preparing an AA Proposal that is Capable of Being Accepted

Our overarching objective is to submit an AA Proposal that delivers for our customers, is underpinned by effective stakeholder engagement and is capable of being accepted by the AER. Our stakeholder engagement program is a key part of achieving our objective. We consider that our AA Proposal has been informed by a comprehensive stakeholder engagement program, the key parts of which are explained in Chapter 5 and include:

- *Initial Customer Workshops* – we held six workshops across the areas/regions covered by our networks to better understand the views of participants on their natural gas supply, including with respect to the reliability and safety of supply;
- *Draft Plan* – a key initiative we undertook was the release of our Draft Plan on 5 July 2016, which Plan outlined the key activities and expenditure we intend to undertake and the prices we propose to charge retailers over the next AA period (see Attachment 1.2 for a copy of our Draft Plan);
- *Stakeholder Engagement on the Draft Plan* – we received feedback on our Draft Plan through a combination of submissions, stakeholder workshops and dedicated meetings with key stakeholders;
- *Further Customer Workshops* – we held two further workshops to discuss our final plans with the same customers that attended the initial customer workshops; and
- *Ongoing Engagement with our Reference Groups* – we have engaged with our Victorian and Albury Reference Group and our Retailer Reference Group on an ongoing basis throughout the development of this AA Proposal (Chapter 5 provides the composition of our two Reference Groups).

We have indicated throughout this Plan how stakeholder feedback has influenced our AA proposal, including through use of ‘traffic light’ tables at the start of each relevant chapter in this Plan.

The information, forecasts and estimates used in our Final Plan have been subject to a rigorous verification process, the key features of which include that:

- forecasts are based on the considerable expertise of AGN and its contractor, APA Asset Management, in providing natural gas distribution services;
- forecasts for projects have been based on robust business plans that have been subject to thorough review as to their compliance with the relevant requirements of the NGL and NGR;
- where possible, forecasts have been based on the most recent actual information available, which information reflects our revealed efficient expenditure/outcomes;
- all relevant drivers of a particular forecast have been taken into account and explained in this Plan, including by providing any data used to derive a particular forecast;
- we rely on independent expert advice in preparing forecast information, and this advice is attached to this Plan; and

- our key models (Roll Forward, Post-Tax Revenue, Capex and Opex models) and our Regulatory Information Notice (RIN)[4] have been independently reviewed and reported on by KPMG, with this report provided as Attachment 1.10 to this Plan.

In addition to the above, we have provided a Statutory Declaration from its Chief Executive Officer, Mr Ben Wilson, verifying that:

- actual information provided in the RIN has been prepared in accordance with the requirements of the RIN and is true and accurate; and
- forecast information provided in the RIN is a best estimate that has been prepared in accordance with the RIN and the basis for that forecast has been provided in our AA Proposal.

The signed Statutory Declaration is provided as Attachment 1.3. The actual and forecast information, including the basis for any forecast, can be accessed in the RIN Index (Attachment 1.4) and the RINs (Attachments 1.5 and 1.6). We have also provided the models used to determine the value of our capital bases for Victoria and Albury (Attachments 1.7 and 1.8 respectively) and the derivation of total revenue and prices (Attachment 1.9).

We are confident that this AA Proposal provides all the required information, complies with all relevant requirements of the NGL and NGR and has been informed by an effective stakeholder engagement program.

1.5. Information Used in this Final Plan

The historical information relied upon in this Final Plan is the most recent actual information available to the business. Due to the timing of the development and submission of our Plan, 2016 data consists of nine months of actual information and three months of estimated information. We will update this information for a full year of actual information in our response to the AER's Draft Decision.

Unless otherwise stated, information presented in our Final Plan is presented in 2017 dollar terms, consistent with the requirements of the RIN issued by the AER.[5]

1.6. Structure of the Document

This Plan is structured in a way similar to that used in our Draft Plan for the networks that was published in July 2016 (Attachment 1.2). Table 1.1 provides further detail on the chapters within this Plan while the Document Map provided at Attachment 1.11 illustrates the relationship of all Attachments to the Plan to the chapters outlined in Table 1.1.

At times, this document relies upon commercial or customer-sensitive information. This confidential information has been redacted from the public version of this Plan and some attachments are not made available to the public. Any such confidentiality claims have been made in a manner that is consistent with the AER's *Better Regulation Confidentiality Guideline*.[6]

Importantly, confidential information has been provided to the AER for its review against the relevant requirements of the NGL and NGR. Attachment 1.12 provides a summary of the confidentiality claims made by AGN with respect to the information provided in this AA Proposal.

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4 A RIN is a notice prepared by the AER in accordance with the National Gas Law that requires the pipeline service provide (in this case AGN) to provide to the AER historic and forecast data relating to the operation of our networks. The RIN is provided at Attachment 1.4.

5 This requirement is set out in our RIN (see Attachment 1.4).

6 AER, *Better Regulation Confidentiality Guideline*, November 2013.

We have sought to minimise the amount of information that we claim confidentiality over to make our AA Proposal as transparent to stakeholders as possible.

Table 1.1: Structure of the Final Plan Document

Chapter	Overview
1. About this Plan	Purpose, requirements and structure of AGN's submission to the AER.
2. About our Business	A description of our business, including the physical network, our customers, services, company vision and performance.
3. Our Track Record	A description of our performance against key metrics over the current AA period.
4. What we will Deliver	A summary of the key outputs/outcomes that we propose to deliver over the next AA period.
5. Stakeholder Engagement	An overview of our stakeholder engagement program, including the development and implementation of the program.
6. Pipeline Services	A description of the services that AGN will provide over the next AA period.
7. Operating Expenditure	A forecast of opex over the next AA period.
8. Capital Expenditure	A forecast of capex over the next AA period.
9. Capital Base	The derivation of the opening and closing capital bases over the next AA period.
10. Financing Costs	The derivation and component analysis of the rate of return, the derivation of the opening and closing tax asset base, a forecast of corporate income tax and the value of imputation credits to apply over the next AA period.
11. Incentive Arrangements	The proposed incentive arrangements to apply over the next AA period.
12. Network Revenue	The derivation of total revenue and the associated price path over the next AA period.
13. Demand Forecasts	Forecasts of customer numbers and natural gas volumes over the next AA period.
14. Network Pricing	A description of the reference tariffs and their application over the next AA period, including a description of the approach and formulae for varying these tariffs.
15. Network Access	A description of the non-price terms and conditions to apply over the next AA period.

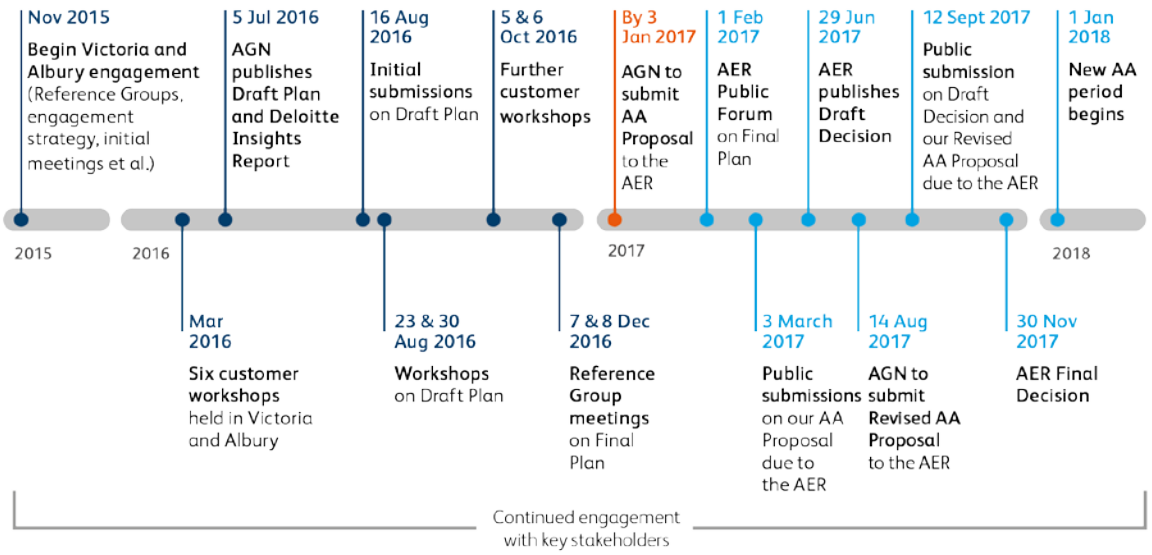
1.7. Next Steps and Feedback Opportunities

We consider that effective stakeholder engagement is vital to achieving our objective of submitting a plan to the AER that delivers for our customers and is capable of being accepted. As already noted, we have implemented a comprehensive stakeholder engagement program in developing this AA Proposal; in particular, through the Draft Plan. The feedback so far received from stakeholders and how it has been considered by AGN has been reported throughout this Plan.

We will engage with stakeholders on an ongoing basis, including during the AER review process. The AER will also seek stakeholder feedback during its own review process, including in response to an AER Draft Decision on our AA Proposal. The key dates for the review of our AA Proposal are set out in Figure 1.2 and include:

- January 2017 – AGN submits its AA Proposal to the AER;
- March 2017 – the AER seeks stakeholder feedback on our AA Proposal;
- June 2017 – the AER releases its Draft Decision on our AA Proposal;
- August 2017 – AGN responds to the AER Draft Decision with a Revised AA Proposal;
- September 2017 – the AER seeks stakeholder feedback on the AER Draft Decision and AGN Revised AA Proposal; and
- November 2017 – the AER releases its Final Decision.

Figure 1.2: Historical and Future Key Milestones



We are also keen to continue to receive any feedback on our AA Proposal directly from our stakeholders at any point in the future. You can provide your feedback through the following options:

- *Online* – visit https://www.australiangasnetworks.com.au/our-business/have-your-say/five_year_plan to lodge your feedback online;
- *Email* – send your feedback to haveyoursay@agnl.com.au;
- *Post* – send your submission to:
  Craig de Laine (General Manager Strategy and Regulation)
  Australian Gas Networks Limited
  Level 6, 400 King William Street
  ADELAIDE SA 5000
  Phone: (08) 8227 1500
- *In Person* – feel free to contact us at haveyoursay@agnl.com.au to arrange a time to discuss your feedback in person.

2. About our Business

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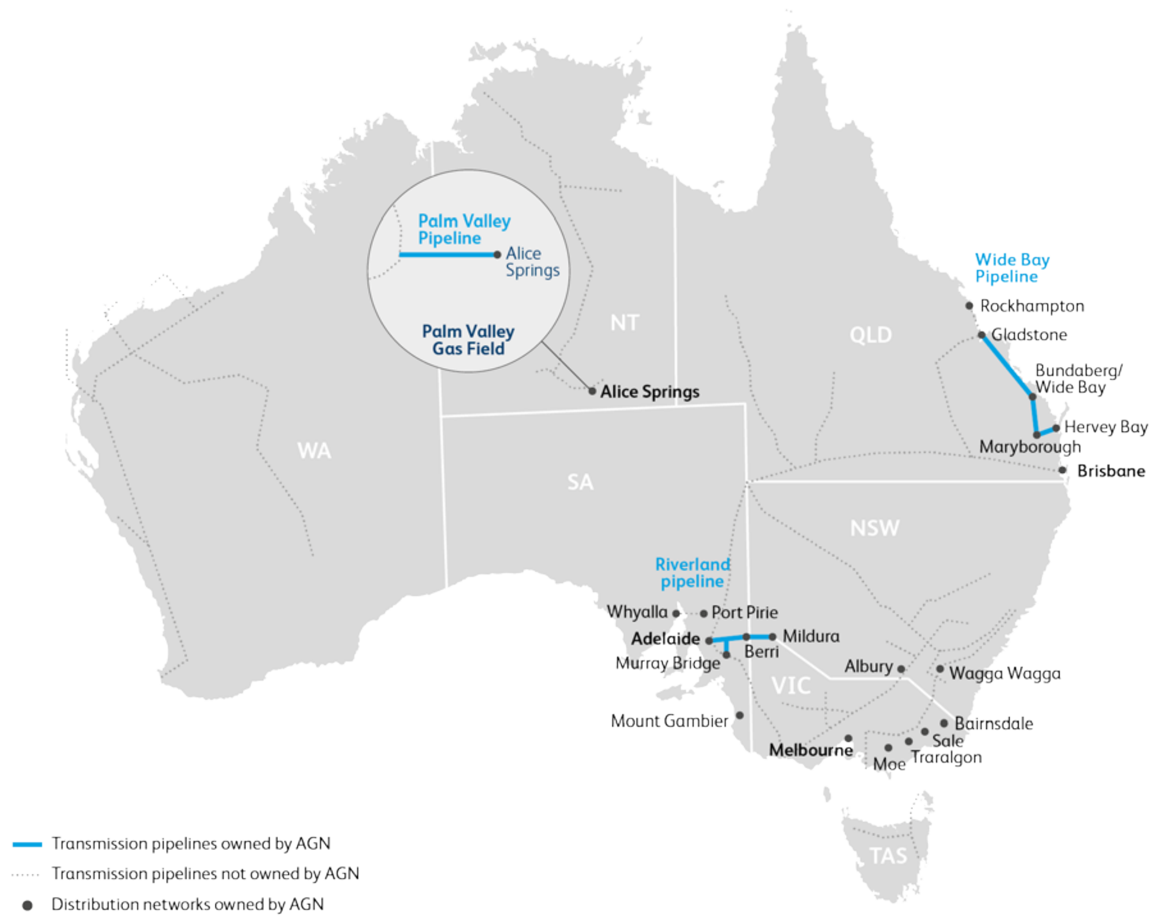
2. About our Business

2.1. Introduction

Australian Gas Networks Limited (AGN) is one of the leading natural gas distribution businesses in Australia, serving around 1.2 million domestic, small business and large industrial customers. We own over 23,000 kilometres of natural gas distribution networks and 1,100 kilometres of transmission pipelines in Victoria, New South Wales, South Australia, Queensland and the Northern Territory (see Figure 2.1). AGN is owned by the Cheung Kong Hutchison Group of companies based in Hong Kong.[7]

This chapter sets out our role in the provision of natural gas to customers as well as our Vision. This chapter also provides an overview of our Victorian and Albury natural gas distribution networks (the networks), including network location and size.

Figure 2.1: Map of AGN's Networks



7 The Cheung Kong Hutchison Group acquired Envestra Limited in August 2014 and subsequently changed the company's name to Australian Gas Networks Limited. Prior to the ownership change, and since its inception in 1997, Envestra Limited was a publicly listed company on the Australian Securities Exchange (ASX). After the acquisition by the Cheung Kong Hutchison Group, AGN was delisted from the ASX in October 2014.

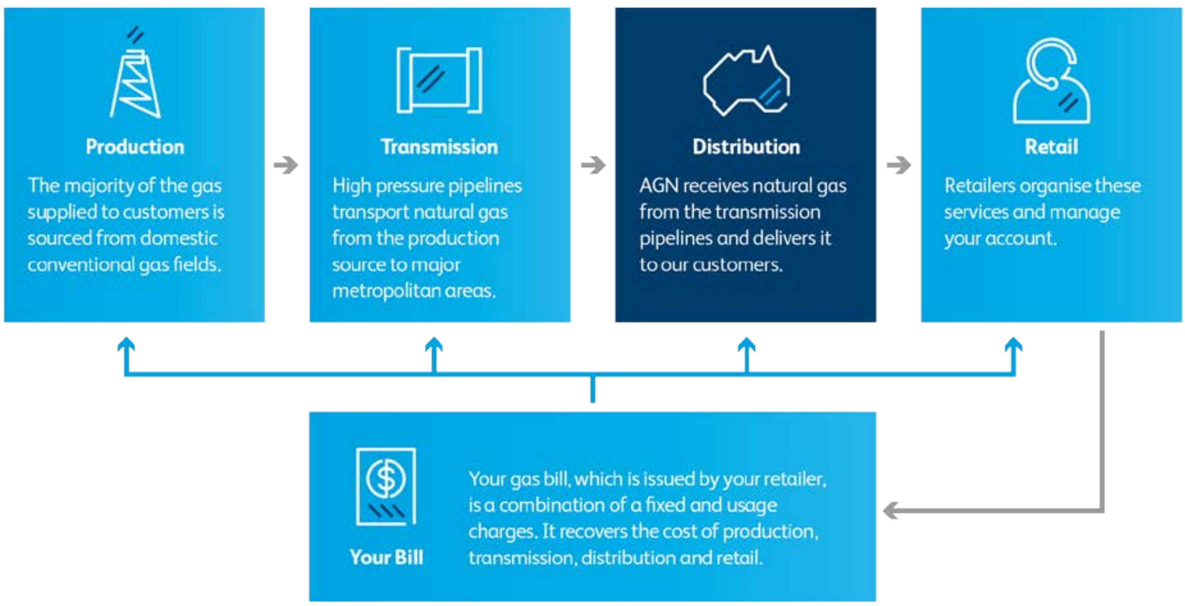
2.2. Our Role

Our role in providing natural gas to customers is illustrated in Figure 2.2. After production, natural gas travels to customers through a high pressure transmission system (usually not owned by AGN) and a distribution network (owned by AGN). We own the distribution network in metropolitan areas that delivers (or transports) gas directly to the customer. We also own and read the meters that measure and record how much gas is used by each of our customers.

Retailers organise the purchase of natural gas from producers and the transport of gas through the transmission and distribution networks to customers. Retailers are also responsible for directly managing the customer account, and as such, are the primary customer reference point in relation to the supply of natural gas. Retailers charge customers for the cost of providing all of the services required to supply natural gas.

We recover our costs primarily by charging retailers and some large industrial customers for transporting natural gas through the networks and for metering and related services (see Chapter 6 for further information on the services that we provide).

Figure 2.2: Natural Gas Supply Chain



2.3. Our Vision: To Be the Leading Natural Gas Distributor in Australia

Our aim is to be the leading natural gas distributor in Australia. Our definition of leading is to achieve top quartile performance compared with other Australian natural gas distributors across all of our key targets. Our Vision sets out the following three key objectives that we consider are consistent with being the leading natural gas distributor in Australia:

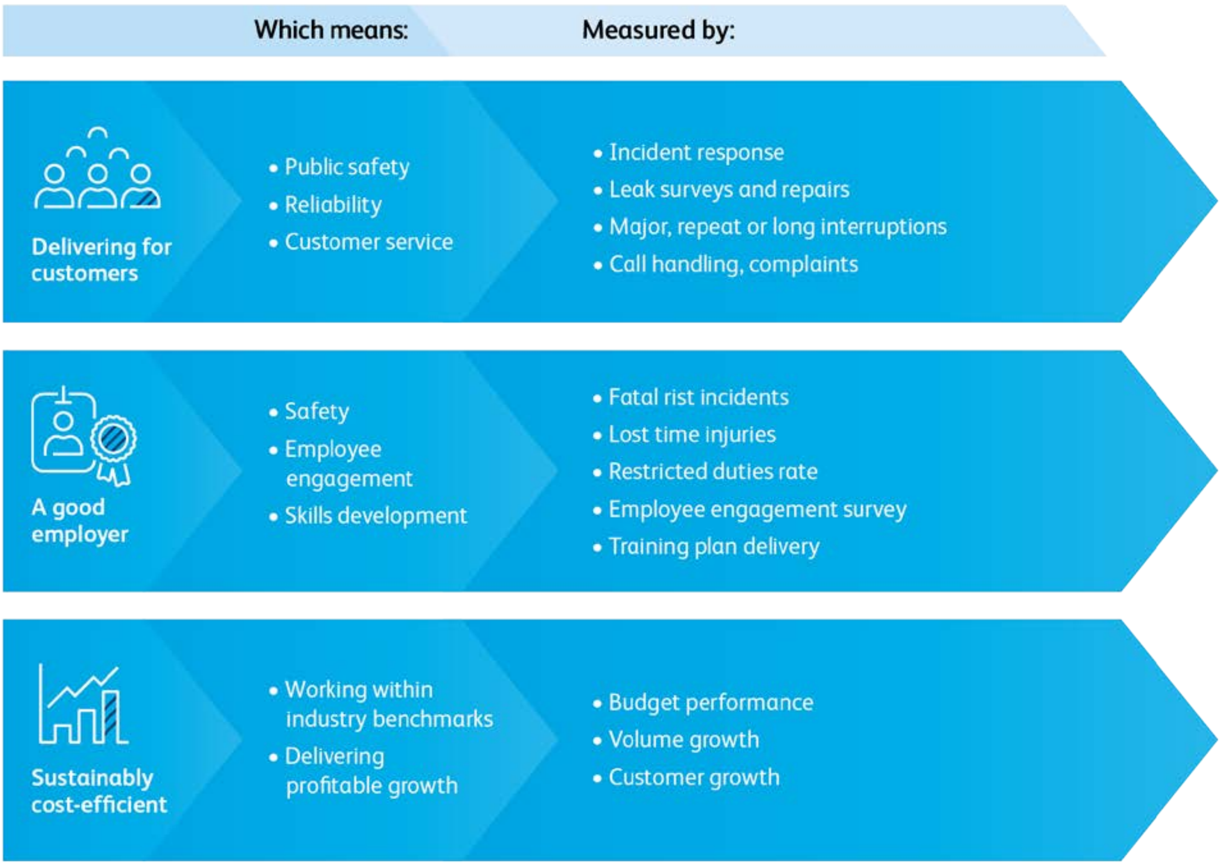
- *Delivering for Customers* – which means ensuring public safety and the provision of high levels of network reliability and customer service;

- *A Good Employer* – which means ensuring the safety of our employees (including contractors), ensuring employees are motivated to achieve our Vision and receive appropriate training; and
- *Sustainably Cost-Efficient* – which means undertaking the required scope/volume of work within the allowances set by the Australian Energy Regulator (AER) while growing the network in a prudent and efficient manner.

We communicate our Vision to all key stakeholders, such as employees/contractors, governments, regulators, investors and our customers. Importantly, all of the objectives set out in our Vision are measured, including in most instances against the performance of our industry peers. We also publicly report on our performance under our Vision, most recently in our 2015 Annual Review (Attachment 2.1), and use it to drive ongoing improvements in our performance.[8]

Figure 2.3 details our Vision and how we measure our performance. Our performance over the current (2013 to 2017) Access Arrangement (AA) period against the Vision is discussed in Chapter 3 of this Final Plan (Plan).

Figure 2.3: Our Vision Statement



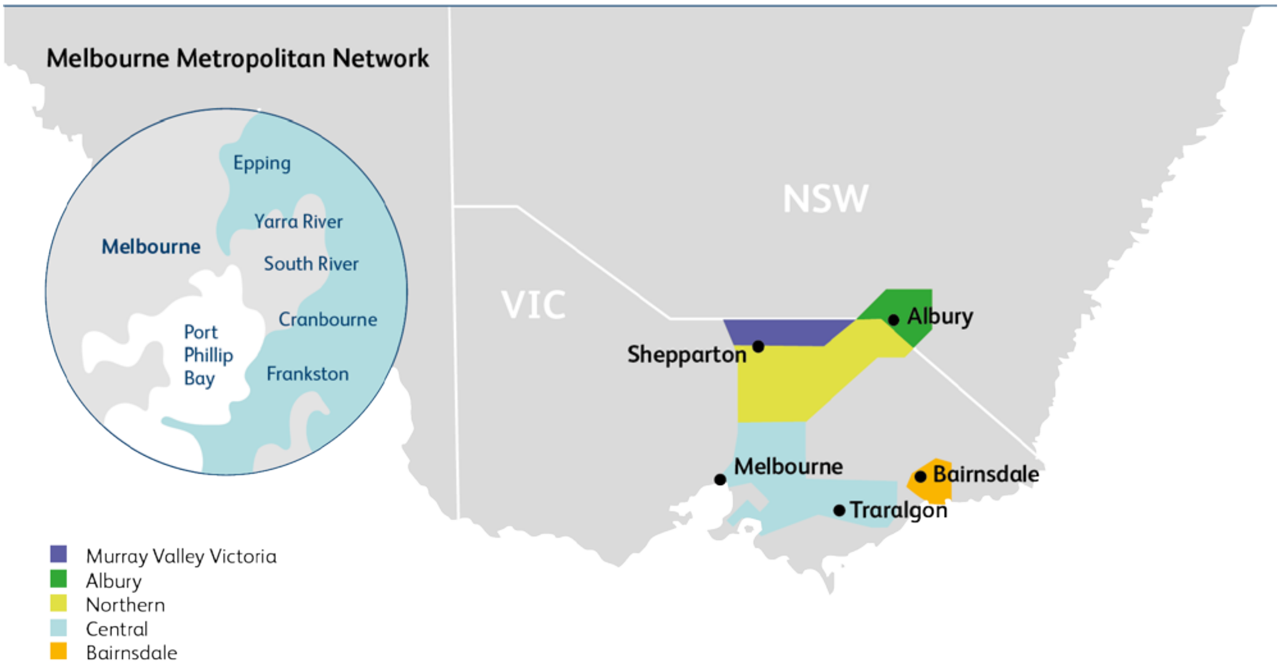
8 Our 2015 Annual Review can also be accessed at http://www.australiangasnetworks.com.au/our-business/annual-reports/annual-reports/.

2.4. Description of the Networks

Figure 2.4 describes the location and key features of our Victorian and Albury networks. Our networks supply close to 650,000 customers through around 11,000 kilometres of predominantly distribution mains. Our networks are located in the city of Melbourne, inner and outer northern suburbs of Melbourne, outer eastern and southern areas of Melbourne, surrounding regional areas (including through to the Mornington Peninsula) and Albury (see Figure 2.4).

The two networks are interconnected, with the Albury network fed from the northern zone of the Victorian network.[9]

Figure 2.4: Area Covered by our Victorian and Albury Networks



	VIC	NSW
Regulated metropolitan networks	Melbourne	n/a
Regulated regional networks	Shepparton, Wangaratta, Wodonga, Moe, Morwell, Traralgon, Sale, Bainsdale	Albury
Length of mains (km)*	10,461	638
Number of customers*	626,106	21,936
Volume transported for 2015 (TJ)	55,843	2,759

* As of 31 December 2015

Note: Regulated networks only.

[9] Further information on our network can be found on our website at: www.australiangasnetworks.com.au.

2.5. Outsourcing Arrangement

Our assets are operated by APA Asset Management (APA) under a long-term Operating and Management Agreement (OMA). The services provided under the OMA include:

- operating and maintaining each network;
- planning, designing and constructing network extensions;
- preparing and settling with AGN the budget for each financial year;
- providing AGN with regular information on financial and other management issues; and
- reading meters and billing retailers.

In consideration for operating the networks, AGN pays for the actual costs incurred by APA in providing the above services (provided those costs are incurred in accordance with strict budgeting constraints), a margin and incentive payments.

The recovery of the margin, referred to in the 2007 OMA as the Network Management Fee (NMF), has been subject to extensive review by the AER in previous AA review processes. Through these reviews it has been decided that the NMF satisfies all the relevant requirements of the NGR in all three of AGN's regulated networks: South Australia, Victoria and Albury.[10] Additionally, the NMF is at the low end of the range of comparable margins eared by similar contractors.[11]

2.6. Summary

We are one of the leading natural gas distribution businesses in Australia, with around 1.2 million customers across most states and territories. AGN is owned by the Cheung Kong Hutchinson Group of Companies based in Hong Kong.

This AA Proposal relates to our Victorian and Albury networks, which supply close to 650,000 customers through around 11,000 kilometres of predominantly distribution mains. These two networks are interconnected, with the Albury network fed from the northern zone of the Victorian network.

We have a clear and measurable vision: to deliver for customers, to be a good employer and to be sustainably cost efficient. Our target is to be Australia's leading gas distributor across these measures.

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10 A copy of the Victorian and Albury OMA is provided as supporting information to Attachment 1.4. In previous AA reviews we have provided substantial evidence to explain the history, commercial reasoning and implementation of our OMAs. As this material has been considered in detail in previous AA reviews, we have not repeated it in this section, but this information can be found at http://www.aer.gov.au/.

11 Please refer to Attachment 2.4 submitted to the AER with our recent South Australian AA Proposal for more information, http://www.aer.gov.au/system/files/Australian%20Gas%20Networks%20-%20Attachment%202.4%20K%20Lowe%20Benchmark%20Study%20of%20Contractor%20Profit%20Margins%20-%20July%202015.pdf.

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3. Our Track Record

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3. Our Track Record

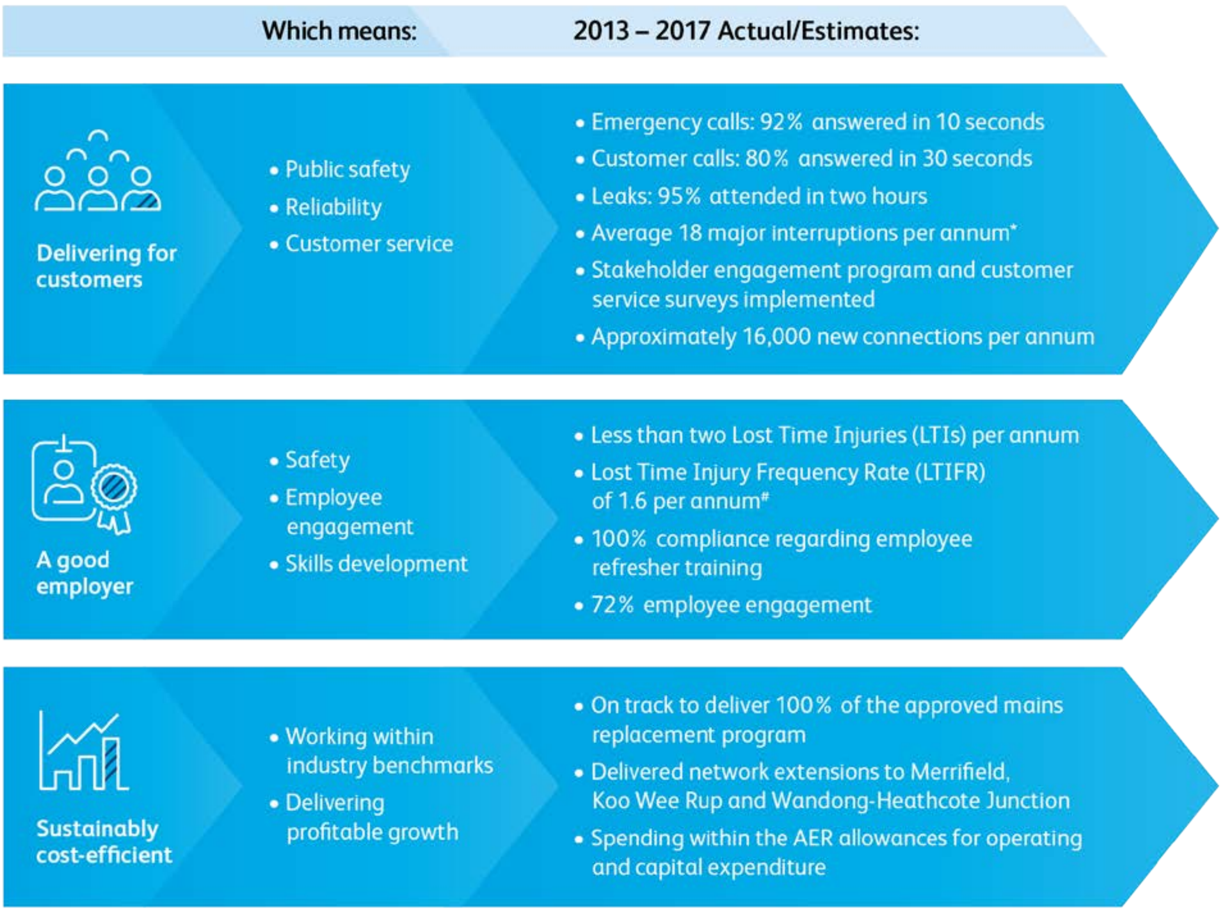
3.1. Introduction

This chapter describes what we have delivered over the current (2013 to 2017) Access Arrangement (AA) period against the targets set out in our Vision.

3.2. What We Have Delivered

As outlined in Chapter 2, our aim is to be the leading natural gas distributor in Australia by achieving top quartile industry performance on all of our key targets. Figure 3.1 summarises our performance in Victoria and Albury over the current AA period against the targets set out in our Vision. Overall, we have met the key safety standards set for the business and delivered the major outputs set by the Australian Energy Regulator (AER) for the current AA period.

Figure 3.1: What We Have Delivered over the Current AA Period



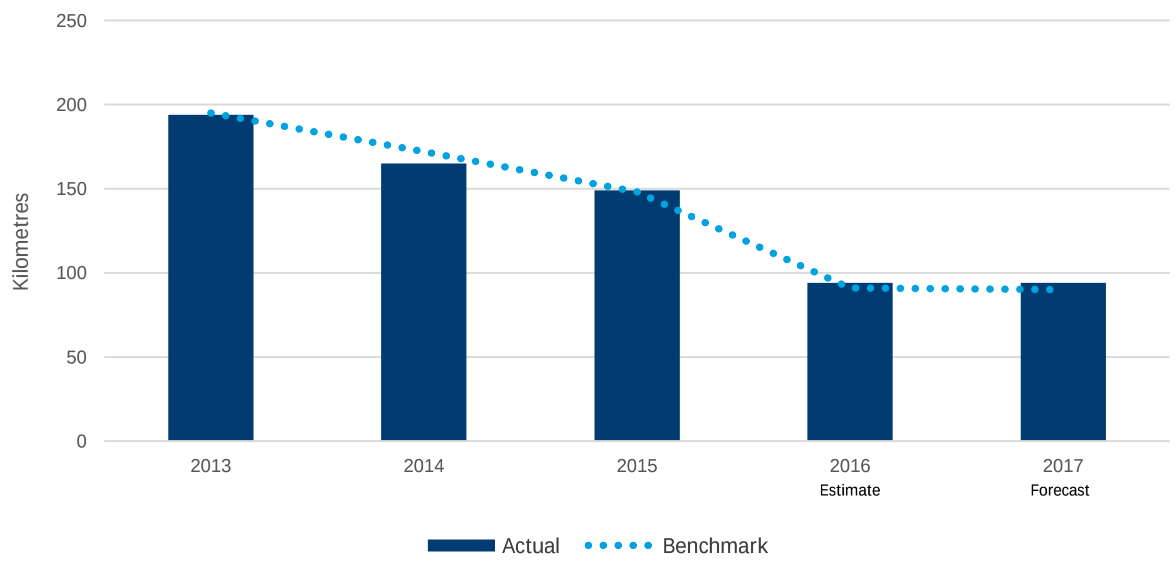
* Major is defined as an interruption affecting five or more customers
# LTIFR is the number of lost time injuries over a year relative to the total number of hours worked in the year

With respect to the Victorian and Albury networks, key achievements over the current AA period include the following:

- *Delivering for Customers* – we have delivered natural gas in a safe manner to our customers, and in doing so, complied with all relevant safety obligations/requirements set for the business. Typically, our customers experience only one supply interruption every 40 years. We have also achieved strong growth in customer numbers, connecting over 16,000 customers to our networks each year;
- *A Good Employer* – we have achieved industry best practice employee safety levels over the current AA period and provided all necessary training to our employees/contractors; and
- *Sustainably Cost-Efficient* – our actual operating expenditure (opex) and capital expenditure (capex) will be below the allowances set by the AER for the current AA period by 10% and 2% respectively, generating savings for customers in the next (2018 to 2022) AA period. We have also maintained our leading productivity performance across the industry (see Section 3.2.1).

Importantly, the estimated reduction in capex has not come at the expense of us delivering our key asset management programs. For example, we intend to deliver the allowed volume of mains replacement over the current AA period, as shown in Figure 3.2. AGN is forecasting to complete the mains replacement program over the next AA period (see Chapter 8). Our mains replacement program is key to ensuring the ongoing safe and reliable supply of natural gas to our customers.

Figure 3.2: Delivery of our Mains Replacement Program



3.2.1. AGN has Delivered Leading Productivity Performance

We engaged Economic Insights to analyse our productivity performance relative to other Australian gas distributors (see Attachments 3.1 and 3.2). The key measure of relative productivity is Multilateral Total Factor Productivity (MTFP), which measures the absolute (or overall) productivity levels across different distributors (where the productivity for each distributor is measured as the ratio of total outputs relative to total inputs used).

The analysis compares the productivity levels of our Victorian network (AGN Vic) with the two other Victorian gas distributors (AusNet Services and MultiNet), Jemena Gas Networks (JGN) in

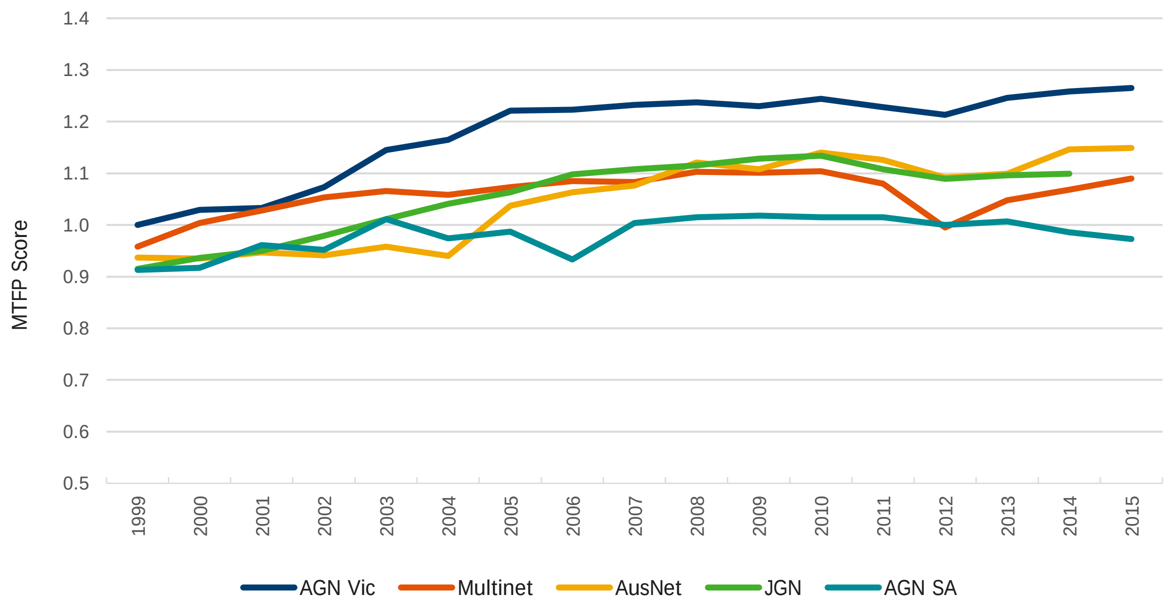
New South Wales and our South Australian (AGN SA) network. The comparative analysis was undertaken for the 1999 to 2015 period, which reflects the period for which data was available for the distributors included in the sample.

Figure 3.3 shows the relative MTFP scores for each distributor, where higher MTFP scores imply higher productivity levels. The analysis shows that our Victorian network, represented by the dark blue line, has the highest productivity level of all gas distributors included in the sample. Economic Insights notes that:

> *"The MTFP results indicate that in the latest years available, AGN Vic is found to have the highest TFP level – an MTFP index of 1.27 in 2015 – approximately 10% higher than the next highest (AusNet) TFP level. AusNet's MTFP index in 2015 of 1.15 is only slightly higher than those of JGN (1.10) and MultiNet (1.09)."* [12]

As noted above, our productivity levels are around 10% higher than the next most efficient distributor and 13% above the industry average. Our leading productivity performance demonstrates that our actual incurred capital and operating expenditure (see Chapters 7 and 8 respectively) are prudent, efficient and consistent with good industry practice.

Figure 3.3: Economic Insights' MTFP Results 1999 to 2015



Source: Based on data from Economic Insights, *The Productivity Performance of Victorian Gas Distribution Businesses*, 15 June 2016. Provided at Attachment 3.1 to this Final Plan.

12 Economic Insights, *The Productivity Performance of Victorian Gas Distribution Businesses*, 15 June 2016, page 34. Provided at Attachment 3.1.

3.3. Summary

We have delivered strong performance in Victoria and Albury over the current AA period. This includes meeting all key safety targets governing the supply of natural gas, providing high levels of network safety and reliability, providing accepted good industry practice levels of employee safety and industry leading productivity performance. We have delivered the key projects that were funded over the current AA period within the allowances that were set by the AER.

We intend to build on this strong performance over the next AA period, as explained in the remainder of this Final Plan.

4. What we will Deliver

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4. What we will Deliver

4.1. Introduction

Our Vision is to be the leading natural gas distributor in Australia. As outlined in Chapter 3, we have delivered against the targets set out in our Vision over the current (2013 to 2017) Access Arrangement (AA) period, including the provision of high levels of community safety, network reliability, customer service and leading productivity performance. We have also delivered the scope of works for the key projects included in the allowances set by the Australian Energy Regulator (AER) for the current AA period.

As explained in this chapter, we plan to continue to deliver high performance levels over the next (2018 to 2022) AA period against our Vision.

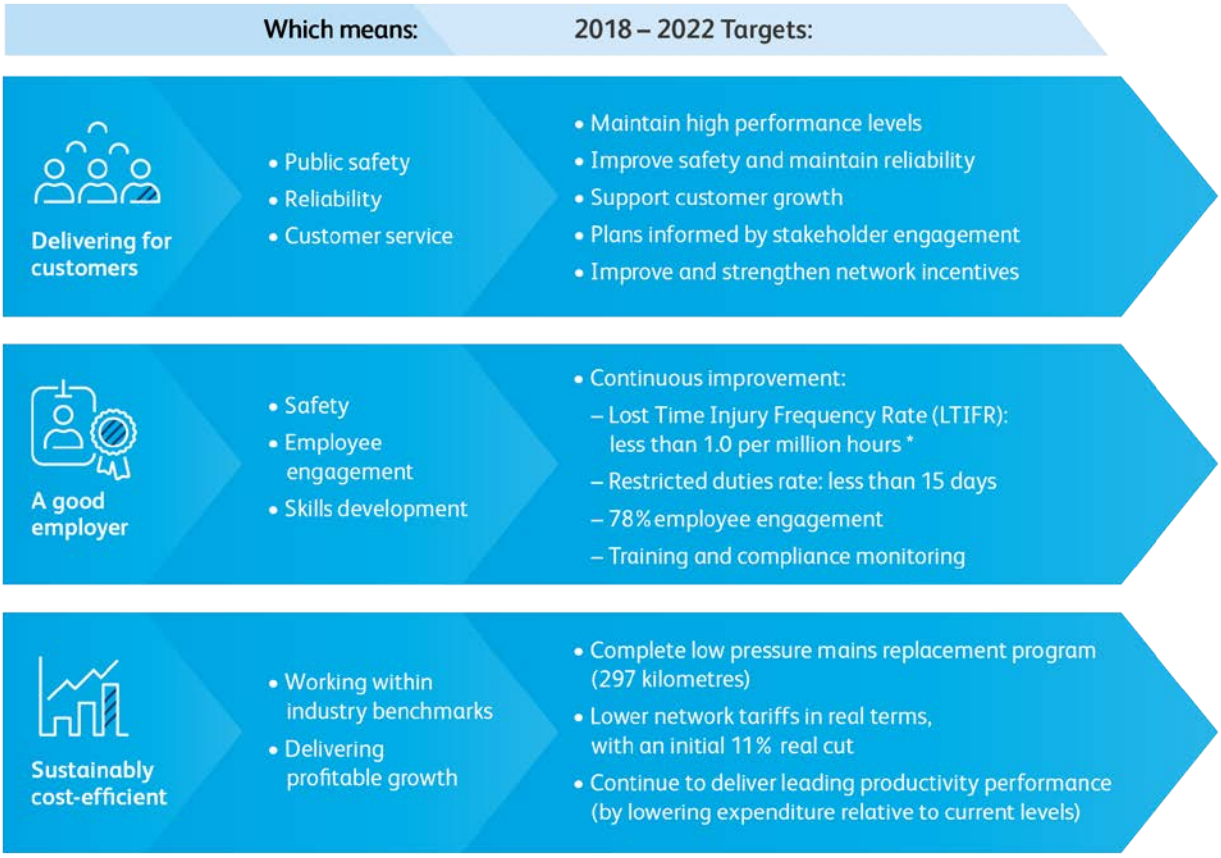
4.2. Delivering on our Vision

Figure 4.1 summarises the key deliverables that we intend to provide over the next AA period against the targets set out in our Vision. In particular, we intend to:

- deliver an upfront 11% reduction in distribution prices (or tariffs) before inflation on 1 January 2018, with prices lower on average over the next AA period compared to current prices (see Chapter 14);
- continue to deliver leading productivity performance, including by reducing total expenditure compared to the current AA period, collectively delivering a $23 million reduction in our costs across the next AA period (see Chapters 3, 7 and 8);
- maintain current levels of reliability and customer service, which is consistent with the feedback we received during our stakeholder engagement program (see Chapters 5, 7 and 8);
- introduce customer satisfaction measurement as a 'business-as-usual' key performance indicator, which will help continue to drive a change in our culture to be a genuinely customer-focused organisation (see Chapter 11);
- improve the safety of our networks, primarily through the completion of the low-pressure mains replacement program, which is also consistent with feedback we received during our stakeholder engagement program (see Chapters 5 and 8);
- continue to grow our networks, with around 16,000 new customers expected to be connected to our Victorian and Albury networks each year (almost 80,000 new customers over the next AA period) (see Chapters 8 and 13);
- drive continuous improvement in employee/contractor safety, undertake regular employee engagement/satisfaction surveys and ensure all employees receive (at least) the training required to efficiently deliver on the requirements of their job; and
- improve and strengthen the incentives for the business to pursue prudent and efficient expenditure whilst maintaining high levels of network safety, reliability and service (see Chapter 11).

Further detail on our key deliverables is provided in the remainder of this chapter.

Figure 4.1: What We Will Deliver Over the Next AA Period



* LTIFR is the number of lost-time injuries over a year relative to the total number of hours worked in that year

4.3. Delivering for Customers

Delivering for customers means ensuring public safety and providing high levels of network reliability and customer service. We consider that the safe and reliable supply of natural gas is the most important driver of business performance. We are also focused on providing high levels of customer service, particularly given natural gas is a fuel of choice for most customers.

As outlined in Chapter 3, we have delivered high levels of network reliability and customer service over the current AA period. In summary, in respect of:

- *Public safety* – we have complied with the safety requirements set out in our Leakage Management Procedure (which outlines the process for managing natural gas leaks on the networks);
- *Reliability* – there has been, on average, only 18 major network interruptions per year; and
- *Customer service* – over 90% of customer calls to our emergency call centre are answered within 10 seconds.

Consistent with stakeholder feedback, we intend to continue to deliver high levels of performance to customers over the next AA period. This will be achieved by:

- ensuring that our business plans have been informed by an effective stakeholder engagement program (which is also relevant to meeting our objective of delivering for our customers and submitting a plan that is capable of being accepted by the AER);
- maintaining the security of supply across our networks, particularly by completing a long-term initiative in the outer eastern/southern parts of the Victorian network through to the Mornington Peninsula;
- continuing to support network growth, including through enhanced marketing activities, with an average of 16,000 new customer connections to the gas distribution networks per year over the next AA period; and
- strengthening the incentives to improve performance through a more comprehensive set of incentive arrangements to apply over the next AA period.

4.4. A Good Employer

Employee safety is a key focus of the business, which is why we have incorporated safety targets in our Vision. We are targeting an improvement in outcomes relating to employee safety over the next AA period. Specifically, we are aiming to reduce the Lost Time Injury Frequency Rate (LTIFR) from 1.6 to less than 1.0 lost time injuries per million hours worked. This will ensure AGN remains at best practice levels of employee safety across the industry.

We will also report on the outcomes of our employee engagement program. Central to this is undertaking regular surveys of employees aimed at testing matters such as whether employees are aware of key business targets (including that set out in our Vision), motivated to achieve and improve on targets and consider there is appropriate support to achieve their own personal objectives (including through access to training).

Related to this, we will routinely monitor over the next AA period whether employees and contractors have received appropriate training for the job they are undertaking for the business.

4.5. Sustainably Cost-Efficient

Being sustainably cost-efficient means delivering the required outputs within industry allowances while growing the networks in a prudent and efficient manner. The key deliverables over the next AA period under this part of our Vision include:

- continuing to deliver on our mains replacement program, particularly the completion of the low-pressure mains replacement program;
- continuing to investigate and support network growth opportunities, including through expanding our marketing program;
- continuing to deliver leading productivity performance, which will be facilitated through reductions in both capex and opex relative to current levels and passing on to customers the benefits of the cost savings we have made in the current AA period; and
- delivering lower distribution tariffs, on average, over the next AA period compared to current (2016) tariffs.

4.6. Summary

Our plans for the next AA period have been informed by an effective stakeholder engagement program. Overall, we are proposing to continue to deliver high levels of safety, network reliability, customer service and leading productivity performance at a lower cost than we have over the current AA period. We are also proposing to deliver an upfront price cut of 11% on 1 January 2018, with lower average prices relative to current levels.

5. Stakeholder Engagement

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5. Stakeholder Engagement

5.1. Introduction

We are committed to achieving our overarching objective of submitting a plan that delivers for our customers, is underpinned by effective stakeholder engagement and is capable of being accepted by the Australian Energy Regulator (AER). Ensuring effective stakeholder engagement is therefore a key part of achieving this objective. This chapter explains our approach to stakeholder engagement and outlines how the program has impacted our plans for the next (2018 to 2022) Access Arrangement (AA) period.

5.2. Regulatory Framework

We are required through this Final Plan to achieve the National Gas Objective (NGO), which requires Australian Gas Networks Limited (AGN) to promote the long-term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.

5.3. AGN Reference Groups

A key part of our stakeholder engagement program has been the establishment of the following two Reference Groups:

- Victorian and Albury Reference Group (VARG) – which comprises representatives from a broad cross-section of key community stakeholder groups; and
- Retailer Reference Group (RRG) – which comprises the retailers operating in Victoria and Albury.

The composition of our two Reference Groups is shown in Figure 5.1. The Reference Groups provide AGN with efficient access to the needs, values, priorities and preferences of a broad cross-section of customers served by our Victorian and Albury natural gas distribution networks. The key role of our Reference Groups is to challenge, guide and review the process of developing and implementing our stakeholder engagement program and to provide feedback on our plans.

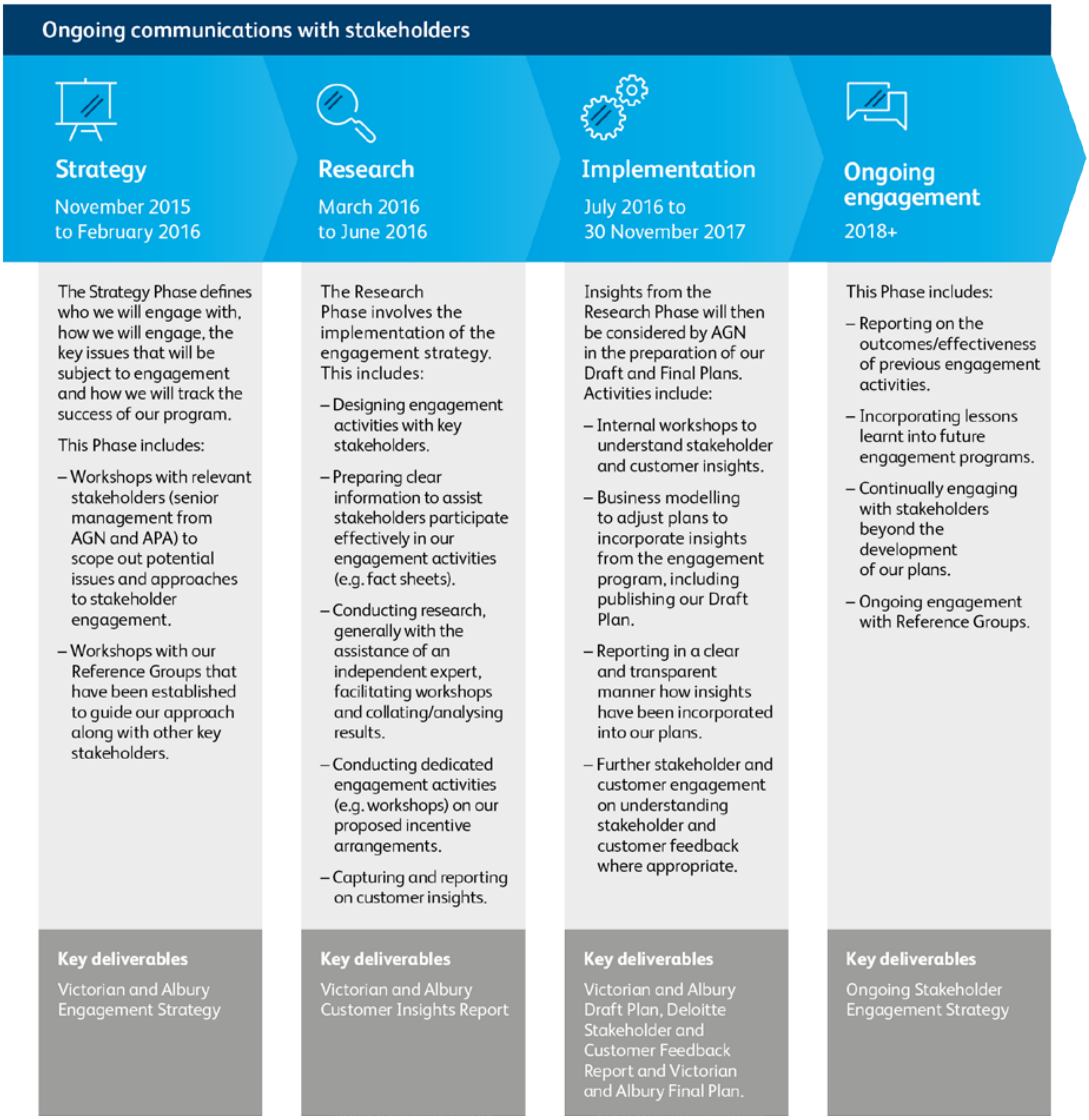
Figure 5.1: Composition of AGN Reference Groups

5.4. Our Approach to Stakeholder Engagement

Our approach to stakeholder engagement comprises four phases (see Figure 5.2). The key features of each stage of our engagement program include:

- *Strategy Phase* – this included the development of our specific stakeholder engagement strategy for Victoria and Albury;
- *Research Phase* – which included, with the assistance of an independent expert, conducting customer workshops, holding one-on-one meetings with stakeholders and collating/analysing the key outcomes from our research;
- *Implementation Phase* – which included internal review of the feedback received during the research phase, development of the Draft Plan, further engagement on our Draft Plan, further customer workshops leading into the development of this Final Plan; and
- *Ongoing Engagement Phase* – a commitment to engage with our stakeholders on an ongoing basis.

Figure 5.2: Our Approach to Stakeholder Engagement



Key documents relating to each phase of engagement are publicly available on our *Have Your Say* website (https://www.australiangasnetworks.com.au/our-business/have-your-say). Attachment 5.1 provides a log of all documents associated with our stakeholder engagement program. The key activities undertaken under each phase are discussed in more detail in the remainder of this chapter.

5.5. Strategy Phase

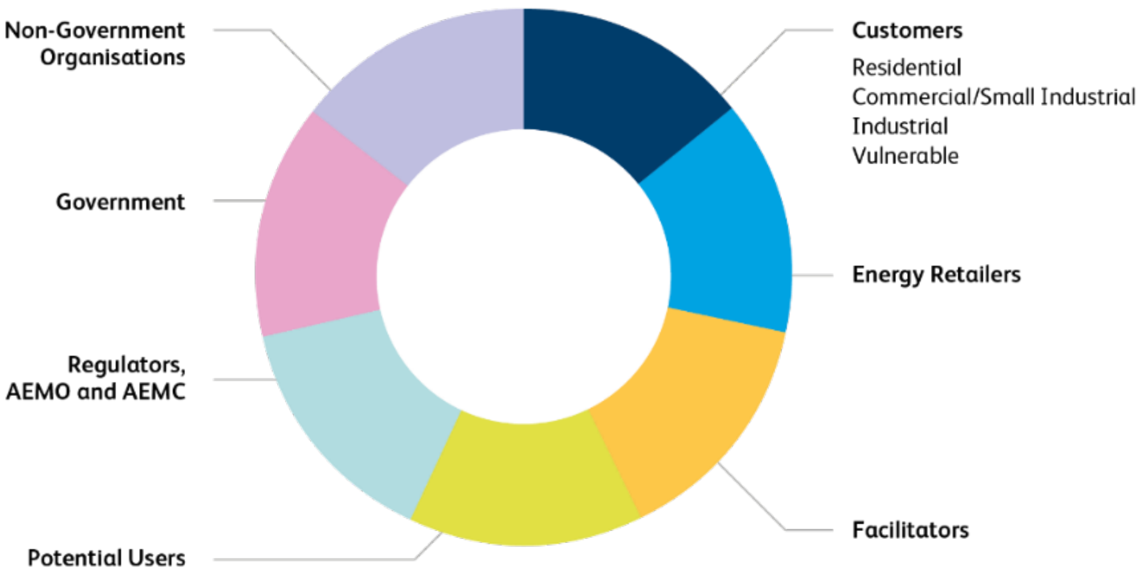
The objective of our Strategy Phase was to develop a robust, fit-for-purpose approach to stakeholder engagement for Victoria and Albury. This Phase included building on key learnings from our South Australian engagement program and engaging with our Reference Groups to ensure our engagement program was designed in a way that would meet our overarching objective.

This process was facilitated through the development of our Stakeholder Engagement Scoping Paper (Attachment 5.2). This Scoping Paper set out our preliminary views on who our stakeholders are and the potential issues for engagement. This paper was distributed (as a draft) to key stakeholders, including our Reference Groups, as a basis for discussion. The Scoping Paper was finalised after receiving feedback from our stakeholders.

Feedback on the Scoping Paper underpinned the development of our overarching AGN Stakeholder Engagement Strategy (Attachment 5.3) and our targeted Victorian and Albury Stakeholder Engagement Strategy (Attachment 5.4). Key outputs of this Phase included identifying our key stakeholder groups, the issues and topics for engagement and the appropriate method for engagement.

The relevant stakeholder and customer groups identified through our Strategy Phase to be included in our engagement program are set out in Figure 5.3.

Figure 5.3: Our Stakeholders and Customers



The key themes for engagement identified in the Strategy Phase include:

- *Customer Experience* – which includes stakeholder awareness of our business and the appropriate/desired level and channels for communicating with customers (e.g. through our website and/or other digital methods of communication);
- *Network Safety and Reliability* – which includes proposed initiatives that are aimed at maintaining and improving the safety and reliability of the networks;
- *Tariff Structures* – which includes customer preferences on how they would like to be charged for natural gas; and
- *Environmental Commitments and Reporting* – which includes customer expectations with regard to reporting on our environmental commitments.

The Strategy Phase identified a mix of engagement methods to receive feedback from stakeholders on the above matters, including through customer workshops and meetings with our Reference Groups.

5.6. Research Phase

The objective of the Research Phase was to develop a better understanding of stakeholder values. The key output from this process was a report from our independent expert advisor capturing the feedback from a series of customer workshops that were held across our networks.

5.6.1. Customer Workshops

We held two customer workshops in metropolitan Melbourne and four workshops in major regional centres (Albury/Wodonga, Shepparton, Narre Warren and Traralgon). Workshop participants were recruited on the basis of gender, age, household income and concession availability to ensure a representative sample of natural gas customers. Overall, 78 residential and commercial customers attended.

Deloitte was engaged as an independent expert advisor to assist AGN with the design, participant recruitment and delivery of the workshops. Deloitte also led the facilitation of the workshops while key management representatives from AGN and APA Asset Management (APA)[13] provided the content relating to our plans. The workshops were designed to:

- explain the role AGN has in supplying natural gas to customers, including explaining those matters that AGN can and cannot control;
- explain the composition of a typical natural gas retail bill, including our view as to the direction of the distribution component of the retail bill (the part AGN is responsible for);
- understand the views of workshop participants on their natural gas supply, including a discussion on key customer values;
- understand the communication preferences of participants, including whether they would prefer to interact with AGN through traditional existing ‘paper’ channels and/or through the use of ‘digital’ channels;
- understand customer preferences for reliability and safety investment options proposed by AGN for the next AA period; and

[13] APA operate the networks on our behalf, see Section 2.5 for further information.

- facilitate open discussion on key topics, such as the environment and tariff structures.

As part of our South Australian engagement program the Consumer Challenge Panel (CCP) provided feedback that:

> *"……the use of anonymous voting methods is essential in such workshops. Without the benefit of anonymity, participants who are not confident to express a view are easily swayed by the opinions of others in the group."*[14]

We were mindful of this feedback and ensured that the Victorian and Albury workshops were structured so that all initiatives were subject to anonymous voting. Of the initiatives that were supported, customers were asked to rank the supported initiatives in order of importance. The cost impact of each initiative (including the various options) and the total cost of all initiatives was clearly communicated prior to customers independently completing their voting sheet.[15]

We also provided a series of Fact Sheets to workshop attendees to assist with their understanding of AGN as a business and our role in the supply of natural gas. These Fact Sheets are provided at Attachment 5.5, whilst the workshop presentation is provided at Attachment 5.6 to this Final Plan.

5.6.2. Customer Insights Report

Deloitte captured and reported on the feedback from the customer workshops in their Customer Insights Report, which has been published on our website and is provided at Attachment 5.7 to this Final Plan. Deloitte in their report distilled the feedback from the customer workshops into nine customer insights, which are summarised in Table 5.1.

The key feedback included that customers:

- would like to access more information about AGN, including our role in supplying natural gas to customers;
- traditionally considered gas a cost-effective alternative to electricity, but are concerned with recent price increases;
- view gas as a reliable source of energy and value the current standard of reliability;
- are supportive of initiatives that maintain reliability and maintain and improve safety of the network; and
- value the control gained by having their gas bill dependent on usage levels.

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[14] AER Consumer Challenge Panel, *Advice to AER from Consumer Challenge Panel sub-panel 8 regarding Australian Gas Networks' (SA) Access Arrangement 2016-2021 Proposal*, 2015, page 5.

[15] Note: The voting sheets and priority lists and an example of the presentation provide at a workshop are available on our stakeholder website (https://www.australiangasnetworks.com.au/our-business/have-your-say) a list of all documents related to the Victoria and Albury engagement process and available on our stakeholder website is provided at Attachment 5.1.

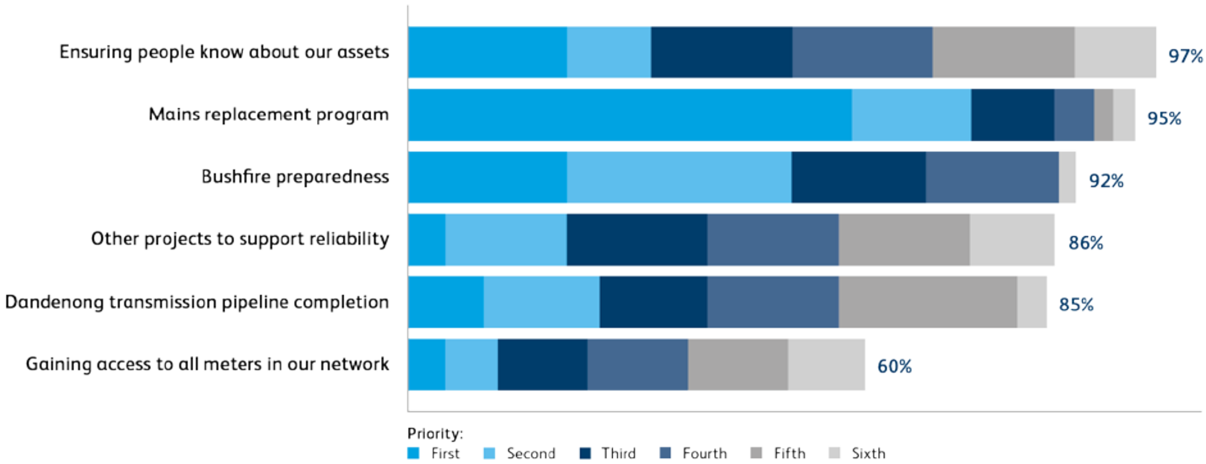
Table 5.1: Customer Insights

Insight	Summary
Customers are not aware of AGN.	The vast majority of customers were not aware of the name or role of AGN prior to the workshop.
Customers do not understand the structure of the gas industry.	Customers did not understand the breakdown of the gas industry (or gas supply chain) and the regulatory model under which AGN operates. They did not know that separate businesses owned and operated different parts of the natural gas supply chain.
Customers traditionally considered gas a cost-effective alternative to electricity but are concerned with recent price increases.	Customers have the perception that the cost-effectiveness of using gas has been eroded in recent years. Customers were still generally accepting of their current price but held a sense of uncertainty over perceived recent upward trends.
Customers would like AGN to be more visible, believing it would improve their experience as customers.	Customers want more information on AGN's role as a gas distributor and believe that some background knowledge would allow them to know where to look for more information if they require it. For example, customers suggested that if they were adequately informed about changes to distribution costs they would be better placed to deal with their retailer when negotiating their retail contracts.
Customers would like to access more information from AGN and favour digital channels.	Customers indicated that they would like to use multiple communication methods to interact with AGN. They generally prefer 'real time' digital channels for greater immediacy and convenience and more traditional communication methods for planned interruptions to their gas supply.
Customers view gas as a reliable source of energy and value the current standard of reliability.	Customers stated that they were satisfied with their current reliability levels and did not support investment to deliver improved reliability (nor did they support lowering prices in return for lower reliability levels). Customers have a slight preference towards longer and less frequent outages over shorter but more frequent outages.
Customers are supportive of initiatives that maintain the reliability and improve the safety of the networks.	Customers felt strongly that the mains replacement program was a necessary investment to maintain safety. Customers are supportive of various other initiatives aimed at improving safety, such as investing to increase the awareness of the location of our gas assets and to install safety devices on new and replacement meters to minimise fire risk. Customers are supportive of projects that are based on upgrading capacity to maintain current reliability levels and to meet customer growth. Customers are less supportive of initiatives when network assets are within the control of individual customers. For example, the project to gain access to certain inaccessible gas meters for meter reads and safety checks.
Customers value the control gained by having their gas bill dependent on usage levels.	The majority of customers indicated a preference to retain the current gas tariff structure, with a relatively high variable component.
Customers would like AGN to play a leadership role in minimising environmental impact.	Customers want AGN to increase transparency over its own actions and on other parts of the natural gas supply chain (including the upstream production and supply of gas).

Customers were asked to vote for the initiatives that they were supportive of AGN undertaking (mindful of the cost impact), by completing a worksheet independently of other workshop participants (consistent with the advice of the CCP). Participants were then asked to rank the initiatives in order of importance. The results of this independent assessment, which are shown in Figure 5.4, provide AGN with guidance as to both the total and relative levels of support.

Overall, customers indicated strong support for most of the initiatives discussed, with the completion of our mains replacement program clearly ranked as their highest priority.

Figure 5.4: Total and Relative Workshop Support for AGN's Proposed Initiatives



5.6.3. Large User Survey

We contacted approximately 30 of our largest (industrial) customers to seek their interest in participating in our engagement program and to understand their current and future service needs. We received nine responses. This reasonably low level of interest is of no surprise given that we are in regular contact with these customers through business-as-usual operations.

In summary, customers were satisfied or extremely satisfied with their current level of reliability. Less than half of our respondents were interested in hearing more about our prices, contingencies for emergencies and future plans for industrial customers, which is likely to reflect the relatively lower share of the retail bill that our network charges make up for this customer group. Information provided from these customers was also used in our industrial demand forecasts (see Chapter 13).

5.6.4. Incentive Arrangements

We are proposing to strengthen the incentive framework that applies to our networks over the next AA period. We put forward a similar proposal in 2015 for our South Australian network, which was not accepted by the AER in part because we had not conducted sufficient industry consultation. The CCP held similar concerns to the AER noting that:

> *"Having considered the AER's [draft decision], and the counter arguments put by AGN in the [revised access arrangement proposal], [the CCP] are persuaded that the lack of standard service reliability measures and the need for additional stakeholder consultation mean that it would be premature to introduce a CESS [Capital Expenditure Sharing Scheme] for the next AA period."*[16]

[16] CCP, *Supplementary advice to AER from Consumer Challenge Panel sub-panel 8 – AGN*, 31 March 2016 page 5.

In response to this feedback, we have conducted dedicated stakeholder engagement on the incentive arrangements that we are proposing to apply in Victoria and Albury. This consultation commenced with the development of an Issues Paper in June 2016 followed by a stakeholder forum in July 2016. Farrier Swier Consulting were engaged to report on the key findings from the engagement process, with its report provided at Attachment 11.3.

Further detail on our dedicated engagement on incentive mechanisms, the key findings from this engagement and our response to that feedback is provided in Chapter 11 of this Final Plan.

5.6.5. Terms and Conditions

We consulted directly with our RRG on our prices and terms and conditions governing access to our networks. This included seeking feedback from the RRG on our draft prices (level and structure) and terms and incorporating this feedback into our Final Plan. Further detail on our engagement activities with our RRG and our response to the feedback received is provided in Chapter 14 (Network Pricing) and Chapter 15 (Network Access).

5.7. Implementation Phase

The Implementation Phase focused on embedding the findings from the Research Phase into our Draft Plan and this Final Plan. Key to ensuring stakeholder feedback was appropriately reflected in our plans was:

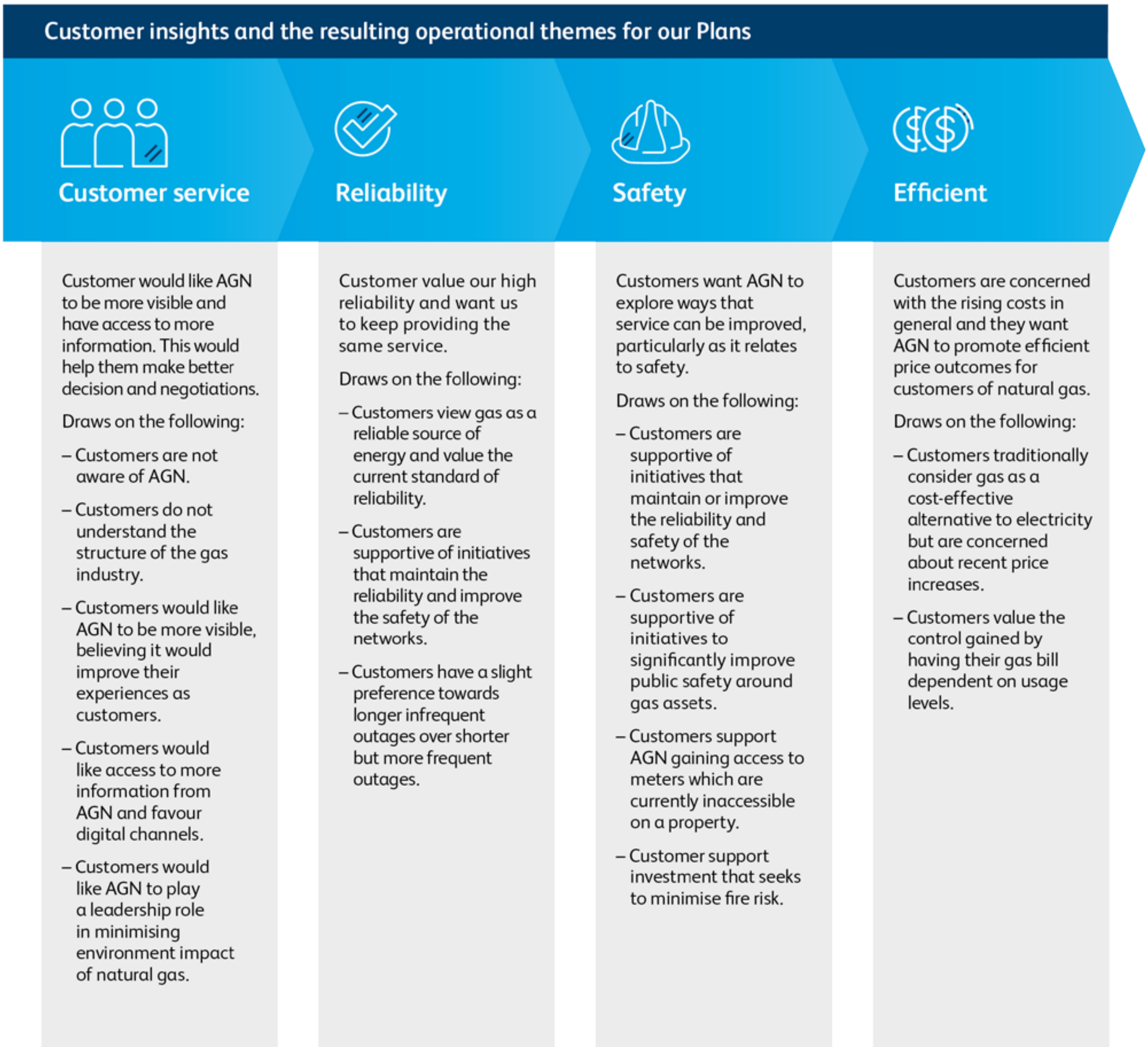
- ensuring that the business as a whole understood any feedback received through our stakeholder engagement program; we have facilitated this by:
    - key AGN and APA personnel being present at customer and stakeholder workshops, including the AGN Chief Executive Officer (CEO), AGN General Manager Regulation and APA General Manager Victorian Networks;
    - dedicated internal workshops to discuss engagement activities and outcomes and distil this feedback into Operational Themes (see Section 5.7.1), which can be integrated into business plans; and
- further engaging with customers and stakeholders, including through the release of our Draft Plan (see Section 5.7.2).

5.7.1. Operational Themes

To assist with the integration of customer and stakeholder feedback into our business, we held a dedicated internal workshop during which the findings of the research phase were discussed and distilled into four Operational Themes, which could then be efficiently integrated into our wider business planning activities.

As illustrated in Figure 5.5, these Operational Themes reference the nine Customer Insights outlined in Table 5.1 and are also consistent with the key targets set out in our Vision (see Section 2.3). Our proposed operating and capital expenditure, as outlined in Chapters 7 and 8 and supporting attachments, reflect these Operational Themes.

Figure 5.5: Customer Insights and the Resulting Operational Themes for our Plans



5.7.2. Draft Plan

A key part of our stakeholder engagement program was the release of our Draft Plan on 5 July 2016.

This was the first time that a gas distributor has released a draft of their entire proposal and represented a significant step forward in our approach to stakeholder engagement. The Draft Plan outlined the feedback from the Research Phase, our response to that feedback, the services we intend to provide, the costs we expect to incur and the prices we propose to charge over the next AA period. The Draft Plan is provided as Attachment 1.2.

The Draft Plan allowed stakeholders to provide input into all or part of our plans in the context of our overall proposal. In our view, this led to a significant improvement in stakeholder understanding of our plans, thereby improving the nature and quality of the feedback received (including by broadening the range of issues that stakeholders could respond to).

We received feedback on the Draft Plan through a combination of written submissions (Section 5.7.2.1), stakeholder workshops (Section 5.7.2.2), customer workshops (Section 5.7.2.3) and industry representation (Section 5.7.2.4). Deloitte reported on the findings from the stakeholder and customer workshops on the Draft Plan, which are outlined in Section 5.7.2.5.

5.7.2.1. Submissions Received on Draft Plan

Our Draft Plan was open for public consultation for six weeks. We published our Draft Plan on our website, issued a media release and directly contacted our key stakeholder groups. We also provided a number of options for stakeholders to provide their feedback on the Draft Plan, including through email, written submission, in person, telephone or through an online survey.

To facilitate feedback we highlighted particular questions throughout the Draft Plan, although we were seeking feedback on all aspects of the plan and not just these questions. We also used these questions as part of our other engagement activities on the Draft Plan, particularly in regard to the stakeholder workshops.

We received three written submissions from the following organisations:

1. Jemena Gas Networks (JGN);
2. Energy Networks Association (ENA); and
3. Origin Energy (OE).

The written submissions were generally supportive, in particular with respect to our approach to engagement. At times stakeholders requested additional information; for example, on the benefits of marketing and the allocation of our Information Technology expenditure between states. Where appropriate, we have included this information in this Final Plan.

The written submissions on our Draft Plan are provided at Attachment 5.8 to this Final Plan. The incorporation of this feedback into our Final Plan is described later in this chapter (see Table 5.5).

5.7.2.2. Stakeholder Workshops on the Draft Plan

We were keen to proactively engage with key stakeholders on the Draft Plan. We held two stakeholder workshops on the Draft Plan, with the first workshop on our operating and capital expenditure proposal and the second on the financial aspects of our plan (rate of return, inflation, capital base, financeability, demand and network pricing). Our workshops were well attended by a diverse cross-section of key stakeholder groups (see Table 5.2).

Table 5.2: Stakeholder Workshop Participants

Workshop 1	Workshop 2
Australian Energy Market Commission	Australian Energy Market Commission
AGL Energy	AGL Energy
Ai Group	Ai Group
Energy Australia	Energy Australia
Energy Networks Association	Energy Networks Association
Council of Small Business Australia	Council of Small Business Australia
Lumo Energy	Lumo Energy
Origin Energy	Origin Energy
Public Interest Advocacy Centre	Public Interest Advocacy Centre
St Vincent de Paul	Consumer Utilities Action Centre
Energy Consumers Australia	
Energy and Water Ombudsman Victoria	

As per the workshops held during the Research Phase, the workshops were facilitated by Deloitte and presented by key AGN and APA management, including the AGN CEO, General Manager Regulation and the APA General Manager Networks.[17] Deloitte were also engaged to capture and report on the feedback, a draft of which was sent to, and verified by, workshop attendees.

The feedback from the stakeholder workshops is reported in the Deloitte Stakeholder and Customer Feedback Report (Attachment 5.10) and our response to this feedback, including how it has impacted this Final Plan, is set out in Table 5.6 (Section 5.7.5). We have reported the stakeholder feedback received on our Draft Plan more generally, including from the stakeholder workshops, throughout this Final Plan (including through summary 'traffic light' tables at the beginning of each chapter[18]).

5.7.2.3. Further Customer Workshops

We held two further customer workshops with 33 participants that had also attended the initial customer workshops in March. The purpose of these workshops was to seek feedback on whether we had captured the feedback from the initial workshops accurately and responded to the feedback appropriately. The workshops were again conducted by key management from AGN and APA, with Deloitte capturing feedback (see Attachment 5.11 for the workshop presentation).

Similar to our Draft Plan, these further customer workshops provided a significant improvement on our previous engagement activities. This is primarily because they allowed the business to test whether our response to the feedback was appropriate in the context of our overall plans,

[17] The presentations given at these workshops are provided at Attachment 5.9 to this Final Plan.

[18] In the 'traffic light' tables, green shading represents no change from the Draft Plan, orange shading represents a modification of the position in the Draft Plan and red shading represents change from the Draft Plan.

including in the context of our proposed prices (which were only provided indicatively at the initial customer workshops).

The feedback included that participants:

- agreed that we had accurately captured and understood the feedback from the initial customer workshops; and
- supported how we had responded to and incorporated their feedback into our plans, including the reduction in price for the initiatives tested.

The feedback was captured and reported by Deloitte in their Stakeholder and Customer Feedback Report (see Attachment 5.10).

5.7.2.4. Industry Representation

As part of our approach to engage with our larger customers, we actively sought partnership opportunities with industry bodies who represent certain large customer groups. This resulted in the AGN CEO presenting our Draft Plan at the following industry events:

- Victorian Energy Forum (VEF) presented by the Energy Users Association of Australia (EUAA), who advocate for the energy needs of Australia's largest energy users; and
- Dairy Australia's Dairy Industry Sustainability Council, which represents a range of AGN's larger customers (rural, large users).

5.7.2.5. Deloitte Stakeholder and Customer Feedback Report

As outlined earlier, Deloitte was engaged to facilitate and report on the implementation phase of our engagement program. The Deloitte Stakeholder and Customer Feedback Report, including a summary of stakeholder feedback from the Draft Plan workshops and further customer workshops, is provided at Attachment 5.10.

One particularly pleasing aspect of the report is the positive feedback that we received from stakeholders on our engagement activities, including how we had incorporated their feedback into our Final Plan.

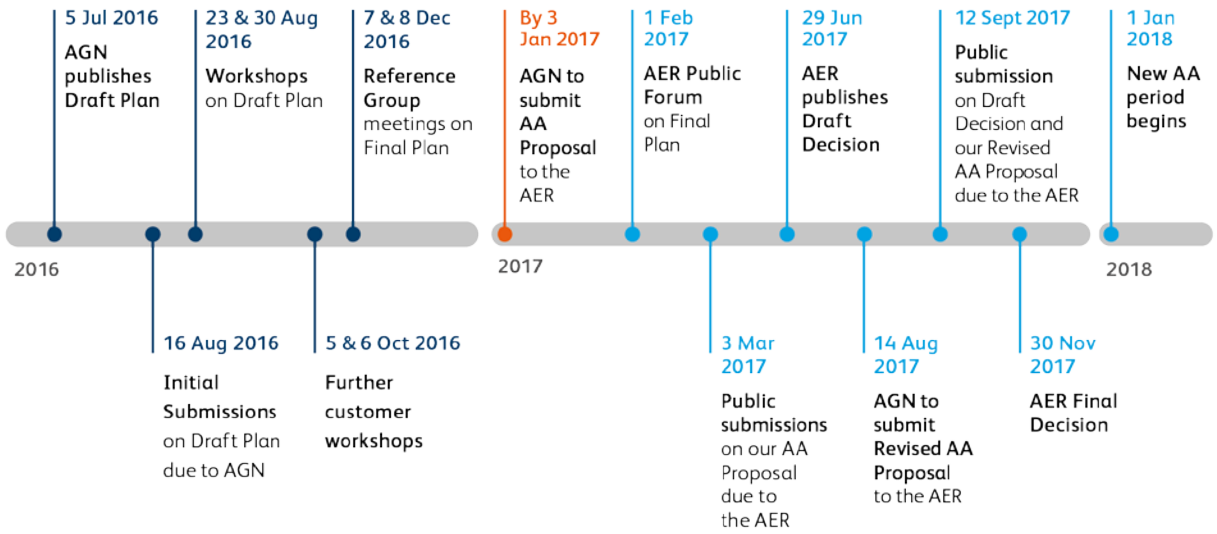
5.7.3. Final Plan

We have transparently reported on the feedback received and how we have reflected the feedback throughout this Final Plan. Where relevant, chapters of this Final Plan include a 'Stakeholder Engagement' section, which highlights feedback received on questions asked in the Draft Plan and how we have responded to this feedback.[19] The incorporation of this feedback is also summarised in Sections 5.7.4 through to 5.7.6.

We will continue to engage with stakeholders throughout this process and note that the AER will also undertake its own engagement program. Figure 5.6 summarises the key dates for the review of our Final Plan, including outlining further engagement opportunities.

[19] These are 'traffic light' tables in which green shading represents no change from the Draft Plan, orange shading represents a modification of the position in the Draft Plan and red shading represents change from the Draft Plan.

Figure 5.6: Historical and Future Key Milestones



5.7.4. Incorporation of Customer Insights and Initiatives

Table 5.3 summarises the insights from our customer workshops (as reported by Deloitte, see Attachment 5.7) and how we have incorporated this feedback into this Final Plan. Table 5.4 provides a summary of how the specific initiatives discussed in our customer workshops have been incorporated into our proposed expenditure, pricing and wider plans. As noted, this feedback has been reported and acted on throughout this Final Plan.

Table 5.3: Incorporation of Customer Insights

Insight	Incorporation into Final Plan
Customers are not aware of AGN.	We are currently delivering a project that will be completed in the next AA period to develop and implement a digital platform (i.e. website) that will improve our ability to engage with customers and various industry partners. A key outcome of this project is the delivery of a better user journey and improved website content, which should assist customers in better understanding who we are and our role within the industry, particularly as it relates to the process of connecting to our network. Additionally, we are proposing to implement a marketing program consistent with that outlined in our Draft Plan. Further information is provided in Attachment 7.1, which outlines that the medium-term benefits to customers exceed the near term costs and that we are working closely with the other Victorian gas distributors to deliver the marketing program. The aim of this project is to increase our customer base, thereby reducing customer bills as a result of our largely fixed costs being spread across a larger number of customers. These projects are discussed in further detail in Sections 7.6.2.2 and 8.6.3 of this Final Plan.
Customers do not understand the structure of the gas industry.	As an objective of our digital program, we will aim to ensure that we clearly describe the structure, roles and responsibilities of relevant bodies within the gas industry on our website. In particular, our new website will feature information to assist customers in understanding the structure of the gas industry, the regulatory model under which we operate, our role within the regulatory model and our component of customer bills.
Customers traditionally considered gas a cost-effective alternative to electricity but are concerned with recent price increases.	We understand that customers are concerned with the uncertainty associated with future gas prices. We have kept this front of mind in the development of our plans. Our modelling incorporates the customer benefits of efficiencies we have achieved in the current (2013 to 2017) AA period and lower financing costs, which results in a 11% upfront price cut to customers from 1 January 2018. Further explanation of this price cut is detailed in Chapter 14 of this Final Plan.
Customers would like AGN to be more visible, believing it would improve their experience as customers.	Consistent with our response to the insights above, we are currently improving our digital capabilities and proposing to increase our marketing activities over the next AA period. We have also increased our media presence through a series of media releases around key issues impacting our business (for example, announcements of key network extensions and pricing decisions). For further discussion on these initiatives, please refer to Sections 7.6.2.2 and 8.6.3 of this Final Plan.
Customers would like to access more information from AGN and favour digital channels.	We consider that this insight is consistent with our current focus on improving our digital capabilities, with a particular emphasis on improving our ability to communicate with customers using digital channels (such as our website). This project is discussed in further detail in Section 8.6.3 of this Final Plan.
Customers view gas as a reliable source of energy and value the current standard of reliability.	Our plans provide for total expenditure which is below current levels and is consistent with maintaining current levels of service and reliability. Built into our proposed forecasts are several key projects that we have identified as required in order to ensure that the current standard of reliability is maintained over the next AA period; in particular, areas of our network. These projects are discussed in further detail in Chapter 8 of this Final Plan.
Customers are supportive of initiatives that maintain the reliability and improve the safety of the network.	We are proposing a range of projects to improve the level of safety across our network. For example, the completion of our low-pressure mains replacement program and installation of fire safety valves in order to reduce the safety risks associated with bushfires. These projects are detailed in Chapter 8 of this Final Plan.
Customers value the control gained by having their gas bill dependent on usage levels.	As the majority of customers (74%) indicated support for a large degree of variability in their gas bills (i.e. through a larger variable component), we have retained the current style of gas tariff structure for the next AA period. For further information regarding our proposed tariff structures, please refer to Chapter 14 of this Final Plan.
Customers would like AGN to play a leadership role in minimising environmental impact.	As detailed in our Environmental Policy, we are committed to seeking economic ways to reduce greenhouse gases emitted from our gas distribution networks and we are continuing to seek additional feedback about particular initiatives that we may be able to undertake over the next AA period.

Table 5.4: Incorporation of Various Initiatives into AA Proposal[20]

Initiatives	Question (estimated bill impact per annum)	Result	Incorporation into Final Plan
Joint Marketing Program	Expand our marketing program? ($3).[21]	94%	94% of participants supported the additional expense of the marketing program on their bill in the short term on the basis that overall bills will fall in the medium term. Further detail on this program is included in Section 7.6.2.2 of this Final Plan.
Mains replacement	Complete remaining 300 kilometres (approximate) of our mains replacement program ($6).	95%	In addition to receiving 95% support for this initiative, completing our mains replacement program was clearly ranked as the highest priority for all customers. We consider the delivery of our mains replacement program consistent with the customer support received for projects improving the overall safety of our network, and as such, have incorporated into ours plans 297 kilometres to complete the low pressure mains replacement program. Further detail on this program is included in Section 8.6.1 of this Final Plan.
	Do nothing.	5%	
Dandenong-Crib Point	Construct new duplicate transmission pipeline to provide supply to region once capacity is reached in 2019 ($1).	85%	85% of workshop participants supported the delivery of this augmentation project. This project has been incorporated into our proposed expenditure in order to ensure the ongoing reliability of supply to customers supplied from this main. Discussion on this project is detailed in Section 8.6.5 of this Final Plan.
	Do nothing.	15%	
Various other augmentation projects	Undertake works to upgrade assets ($3).	86%	Consistent with the insight that customers valued initiatives aimed at maintaining the current level of reliability provided, customers indicated 85% support for a range of additional augmentation projects to be delivered over the next AA period. We are continuing to propose a range of projects over the next AA period that we consider necessary to ensure we continue to maintain current levels of reliability. These are discussed in Section 8.6.5 of our Final Plan.
	Do nothing.	14%	
Public Awareness	Update Dial Before You Dig (DBYD) form ($0.10).	21%	Although there was mixed sentiment as to which approach was the more effective balance of risk and cost, customers leant toward supporting a comprehensive approach to improving public awareness of our gas assets, with 49% of customers supporting the most comprehensive campaign scope. We have considered this feedback and have developed an alternative project scope that seeks to ensure an effective balance of risk mitigation and cost efficiency. The amended scope will see AGN increasing awareness through other initiatives (digital capabilities, marketing) as opposed to a dedicated new project and associated expenditure.
	Targeted marketing (trade magazines) and update DBYD form ($0.50).	28%	
	TV/radio campaign, target marketing and update DBYD form ($3).	49%	
	Do nothing.	3%	
Inaccessible Meters	Take action to access meters by increased communication and/or relocating meters ($0.50).	60%	Around 60% of customers supported AGN gaining access to meters when they are otherwise inaccessible on a property. We found that customers are less supportive of this initiative given that these meters are within the control of individuals. Given the lower levels of support for this project and with a view to balancing risk mitigation and cost efficiency we have not proceeded with this initiative in our Final Plan. Additionally, we believe that increasing awareness through other initiatives (digital capabilities, marketing) will assist increasing awareness with respect to accessing meters.
	Do nothing.	40%	
Fire Safety Valves	Fit devices in bushfire areas only ($0.50).	31%	94% of customers supported the installation of fire safety valves (thermal safety devices (TSDs)) to gas meters in order to improve the fire preparedness of properties, whilst more support was provided for rolling out TSDs to all new and replacement meters (i.e. not restricted to bushfire risk areas only). We have incorporated this project into our proposed expenditure plans; however, have restricted the scope to the installation of TSDs to all new and replacement meters in bushfire risk areas only as we consider that this achieves an appropriate balance between managing both risk and cost at the time of our submission. This project is discussed in more detail in Section 8.6.7.
	Fit devices to all new and replacement meters ($3.60).	63%	
	Do nothing.	6%	

Note: Totals may not add due to rounding.

[20] Note: Please refer to Deloitte's *Customer Insights Report* (Attachment 5.7 to this Final Plan) for further detail regarding Preference Voting.

[21] Note: This was tested only in the secondary customer workshops.

5.7.5. Incorporation of Written Submissions on our Draft Plan

Table 5.5 provides a summary of how written feedback on our Draft Plan (see Attachment 5.8) has been incorporated into this our Final Plan.

Table 5.5: Incorporation of Written Submissions on our Draft Plan

Feedback	Raised By[22]	Incorporation into AA Proposal
Strong support for enhanced customer engagement and AGN's proactive approach.	ENA, OE	We have continued to implement our proactive approach to engagement.
Support for AGN's customer insight that customers value safety and reliability.	JGN	Our plans are focused on maintaining reliability and improving safety – consistent with customer insights and this feedback.
Stakeholders would benefit from AGN publishing forecast price cuts by individual cohort (residential, commercial and industrial).	JGN	This has been included in our Final Plans, see Section 14.6.3.
Support for price-cap regulation which promotes an incentive to grow network utilisation.	JGN	We are proposing to maintain our price-cap regulation, see Section 14.8.1.
AGN should adopt the AER's approach to forecasting operating expenditure and consider additional activities as step changes.	OE	We are continuing to adopt the AER's approach most recently taken for our South Australian network to forecasting operating expenditure, consistent with our Draft Plan.
Support of AGN's proposed marketing program. Gas is a fuel of choice with declining consumption per connection, marketing assists new connections, which therefore puts downward pressure on prices.	JGN, OE	Consistent with our Draft Plan, we are proposing to expand our marketing program, in conjunction with the other two Victorian natural gas distributors.
AGN took a different approach to JGN in relation to output growth, JGN keen to participate in industry wide consultation on the matter.	JGN	We have calculated output growth based on a forecast of customer numbers only and have received further support for this approach from an expert adviser, which advice is provided as Attachment 7.3 to this plan. We included discussions on output growth at our stakeholder workshops. We are also supportive of industry-wide consultation before the AER adopts a "common" approach to calculating output growth.
Request further information in relation to the proposed marketing program, specifically on rebates, time horizon of campaign, costs and contributions, success measures and option analysis.	OE	Further information on our proposed marketing program is provided in Attachment 7.1.
Request AGN provide a better understanding of how new connection expenditure compares with other networks in terms of per unit connection cost and the net present value of connection.	OE	The stakeholder workshops and this Final Plan proposal contains additional information on all aspects of our capex proposal, including growth. We consider our connection costs compare favourable with the other distributors.
Request a better understanding of how IT expenditure has been allocated across networks.	OE	Section 8.6.3 of this Final Plan and our IT Plan (see Attachment 8.5) provides further detail on our IT initiatives, noting that these plans are consistent with our recently approved approach in South Australia.
Support of proposed strengthening of incentive mechanisms – believe it is in the long-term interests of customers. Support gas adopting common incentive approaches to electricity and note that extensive consultation has already occurred for electricity. Support AGN's commitment to work with the AER in relation to the design of such a scheme.	ENA	Our Final Plan is consistent with our Draft Plan in proposing a strengthened incentive mechanism framework. Details of our engagement activities on our proposed incentive schemes are also outlined in Chapter 11.

[22] As described in Section 5.7.2.1 we received written submissions of the Draft Plan from the Energy Networks Association (ENA), Origin Energy (OE) and Jemena Gas Networks (JGN).

Support adoption of AER approach to cost of debt and cost of equity.	OE	As outlined in Chapter 10, we are continuing to adopt this approach in our Final Plan pending further information resolving current areas of uncertainty..
Support flexible depreciation to promote long-term efficient investment in gas infrastructure.	JGN, ENA	As outlined in Chapter 9, we are continuing to adopt this approach in our Final Plan.
Consider that it is appropriate for the AER to consider financeability under the National Gas Rules (NGR).	ENA	Agreed, we believe that we (and the AER) should consider whether our proposal (or in the case of the AER, its decision) provides sufficient revenue/cash flow for a business to achieve the assumed credit rating (of BBB+/Baa1) (see Section 12.5).
Support of modelling cross price elasticity given declining consumption per connection.	JGN	As outlined in Chapter 13, we consider cross price elasticity in the development of our demand forecasts.
Support AGN reduction in distribution tariffs, whilst maintaining high levels of reliability.	ENA	As outlined in Chapter 14, we are continuing to adopt this approach in our Final Plan.
Support the adoption of simple transparent network tariffs – as long as there is no cross-subsidy or equity issues.	OE	In response to stakeholder feedback in our Draft Plan we have decided not to align pricing zones. We will further consider this initiative, and if pursued, seek alignment over a longer time period. We also maintained our decision from the Draft Plan to not consolidate pricing bands (see Chapter 14).
Feedback on four specific clauses (12.8, 22.3, 34.7 and 39.3) in our Terms and Conditions.	OE	We accepted Origin Energy's comment and amended clause 12.8 to recognise that different legislative obligations apply in Victoria and New South Wales. We provided greater clarity regarding the definition of the term 'should become known" as requested. We also provided clarification on insurance and assignment as requested. Table 1, Attachment 15.1 details all the engagement activities on the Terms and Conditions.
JGN supports providing customers with clear messages of the benefits of natural gas such as AGN's emphasis that natural gas remains a highly cost-effective and clean domestic fuel.	JGN	Agreed, this is part of our Vision (see Section 2.3).

5.7.6. Incorporation of Draft Plan Workshop Feedback

Table 5.6 provides a summary of how feedback received during our stakeholder workshops on the Draft Plan (see Attachment 5.10) has been incorporated into this our Final Plan.

Table 5.6: Incorporation of Draft Plan Workshop Feedback

Component	Stakeholder Feedback	Incorporation into Final Plan
Operating Expenditure Forecasting Approach	Stakeholders agreed that AGN's base year operating expenditure was efficient and appropriate. Stakeholders also agreed that operating expenditure closely aligned with customer numbers and not throughput and AGN's approach to output growth was reasonable.	We have not sought additional funding for identified changes in costs. We believe we can continue to meet our current service levels under the operating expenditure forecasts in the next AA period.
Operating Expenditure – Marketing Initiative	Stakeholders were supportive of AGN creating a similar marketing program to that in South Australia, however, was dependent on AGN demonstrating that the benefits exceed the costs.	We are proposing to implement a marketing program consistent with that outlined in our Draft Plan. Further information is provided in Attachment 7.1, which outlines that the medium-term benefits to customers exceed the near-term costs and that we are working closely with the other Victorian gas distributors to deliver the marketing program.
Capital Expenditure Forecasting Approach	Stakeholders agreed with the AGN approach of adopting positions from the South Australian process.	Our approach to forecasting capital expenditure is consistent with that outlined in our Draft Plan and that approved by the AER for our South Australian network.
Capital Expenditure – Mains Replacement	Stakeholders were supportive of AGN completing its mains replacement program and agreed that detailed engagement with Energy Safe Victoria (ESV) was necessary and the right approach and highlighted the importance of coordinating works with other utility companies where possible.	Our proposed mains replacement program is consistent with that outlined in the Draft Plan. We have engaged with the ESV on our mains replacement program. ESV has written to AGN endorsing our proposed volume of mains replacement over the next AA period.
Return on Capital	Stakeholders were supportive of AGN's approach to setting the rate of return and acknowledged AGN's preferred approach to seek to resolve issues with the AER and stakeholders rather than through appeal.	Our Final Plan continues with the application of the AER's positions pending further resolution of the present uncertainty arising from merit and judicial review activity, see Chapter 10.
Capital Base and Financeability	Stakeholders considered the adjustment of the capital base to be a largely mechanical matter. Stakeholders supported AGN's approach to determine regulatory depreciation; in particular, stakeholders supported aligning the economic and technical life of the low-pressure assets scheduled for replacement at the end of the next AA period. Stakeholders believed that a consideration of financeability during the regulatory review process to be reasonable, with adjustments only provided where a business is below the required credit metrics over the regulatory period. Stakeholders considered both the RBA approach (preferred by the AER) and the market-based approach (preferred by AGN) had merit. Stakeholders considered the RBA as a reputable independent source but noted the market-based approach more closely aligned with both the information used to set the rate of return and with actual inflation.	We have adjusted our capital base consistent with the requirements of the NGR. We have also sought to depreciate the residual value of the low pressure mains and associated services by the end of the next AA period, by which time of all of these assets will be replaced. See Chapter 9 of this Final Plan. We believe that we (and the AER) should consider whether our proposal (or in the case of the AER, its decision) provides sufficient revenue/cash flow for a business to achieve the assumed credit rating (of BBB+/Baa1). See Section 12.5 of this Final Plan. Consistent with our general regulatory strategy, we have applied the AER preferred approach to estimating inflation pending further discussion with the AER and stakeholders during this review process. In this regard, we have provided additional information in this Final Plan that addresses certain concerns raised by the AER in our South Australian AA review process in relation to the market based approach.
Demand and Network Pricing	There was general stakeholder support for the approach (same approach to South Australia) taken to demand forecasting; however, stakeholders questioned if prior demand was an indicator of future demand. Stakeholders questioned whether AGN could consider an alternate price model that enabled all customers to share in the aggregate price reduction.	The approach to forecasting demand has the flexibility to capture the impact of drivers of future demand which are not present in the historic demand data. In this regard, we note that our forecasts reflect the future expectations of gas and electricity prices. See Chapter 13 of this Final Plan. Based on feedback, we have decided not to align pricing zones. We will further consider this initiative, and if pursued, seek alignment over a longer time period. We also maintained our decision from the Draft Plan to not consolidate pricing bands (see Chapter 14 of this Final Plan).

5.8. Ongoing Engagement Phase

The objective of the Ongoing Engagement Phase is to both evaluate the effectiveness of our engagement activities (to facilitate ongoing improvements) and to continually engage with stakeholders.

Furthermore, we are engaging with stakeholders as part of our business-as-usual operations. This includes engaging directly with our Reference Groups, large industrial customers, undertaking stakeholder surveys on issues such as brand awareness and by directly measuring customer satisfaction with the service levels we provide. With regard to the last point, our customer satisfaction survey includes engaging an independent expert to:

- each month, survey customers that have had a recent interaction with AGN, including through an unplanned interruption, planned interruption or customer connection;
- measure our customer service performance in respect of the above three types of interactions; and
- report on our performance, including how this performance changes over time.

Our ongoing engagement activities allow AGN to continually understand customer and stakeholder issues and improve the service levels we provide. As noted earlier, effective stakeholder engagement is a key part of ensuring that we are promoting the interests of our customers.

5.8.1. Feedback on our Stakeholder Engagement Program

We sought feedback on the structure and potential improvements of our stakeholder engagement program in our Draft Plan. Table 5.7 summarises stakeholder feedback on our engagement program against the questions asked in our Draft Plan and how this feedback has been incorporated into our Final Plan and ongoing engagement activities.

Table 5.7: AGN's Stakeholder Engagement Performance

Draft Plan Stakeholder Question	Stakeholder Feedback	Our Response to Feedback
Do you have any comments on the structure or implementation of our stakeholder engagement program?	Stakeholders were supportive of AGN's approach to stakeholder engagement; in particular, commenting on the early timing of the engagement and the level of detail that AGN was sharing.	We are committed to continuously improving our approach to engagement and appreciate the supportive comments on the delivery of our program.
Do you have any suggestions as to how AGN could improve on and/or extend its stakeholder engagement program?	Stakeholders appreciated AGN's approach to engagement, but noted that there is always more than could be done. Stakeholders suggested AGN consider: • using surveys to reach more customers; • hold more detailed deliberative discussions; and • provide greater targeting of information to the general public. Stakeholders also advised AGN to continue to strengthen their move towards customer centricity by conducting regular engagement beyond the period leading into the development of the AA Proposal.	We are committed to continually engaging with customers and stakeholders. We engage with stakeholders as part of our business as usual operations. This includes engaging directly with our Reference Groups, large industrial customers, and by directly measuring customer satisfaction with the service levels we provide. Additionally, we are currently delivering a project that will be completed in the next AA period to develop and implement a digital platform that will improve our ability to engage with customers and various industry partners. A key outcome of this project is the delivery of a better user journey and improved website content and navigation. Feedback received on this program will be considered, and implemented as appropriate into future engagement activities.
Do you think this Draft Plan facilitates improved stakeholder engagement?	Strong support for enhanced customer engagement and AGN's proactive approach including the release of the Draft Plan.	We believe that our Draft Plan, which was an important part of our stakeholder engagement program and an industry first, provided stakeholders with an important opportunity to provide feedback on our plans. We received three written submissions as detailed in Section 5.7.2. We also held two stakeholder workshops on the Draft Plan. We heard that stakeholders prefer multiple channels to provide feedback rather than the traditional written submission due to time and resource constraints.

Stakeholders in their written submissions provided the following comments on our engagement program:

> *"The ENA acknowledges the proactive approach to customer engagement taken by AGN leading into providing its final plan to the AER. The ENA notes recent comments made by AER Board member Ms Cristina Cifuentes at the ENA 2016 Regulation Seminar where she recognised the AGN's stakeholder engagement program as a positive initiative."*[23]

and

[23] ENA, *ENA comments on AGN's Draft Plan – A five year plan for Victorian and Albury natural gas distribution networks,* page 2. Provided at Attachment 5.8.

> *"Origin values the co-operative approach adopted by AGN, most notably through the establishment of its retailer reference group. We consider that the Draft Plan is a worthwhile and constructive initiative which allows stakeholders the opportunity to raise areas of both concern and support ahead of the formal submission of the revised Access Arrangement."*[24]

Additionally, tracking and reporting transparently on our performance is an important part of our stakeholder engagement strategy. Table 5.8 outlined the key performance indicators that were developed and our assessment of our performance against these indicators, based on feedback from stakeholders.

Table 5.8: AGN's Customer Engagement Performance

AER Principle	Measurement and Target	Our Performance
Clear, accurate and timely communication	• Satisfaction measures: ◦ educational materials used during customer workshops; and ◦ the process for engagement (how clearly materials were presented). • Measured by a 70% or above satisfaction score.	96% of Round 1 Customer Workshop participants and 97% of Round 2 Customer Workshop participants agreed the workshops were run well and met expectations Stakeholders at our Draft Plan and Final Plan Workshops agreed that the presentation materials provided adequate insights and information into our Draft Plan/Final Plan and were presented in a manner that was easy to understand. Our Reference Group's also agreed that meeting materials were presented in a manner that was easily understood and provided adequate information and insights into the relevant topic.
Accessible and inclusive engagement	• Endorsement from Reference Groups that engagement reaches a representative group of the target population. • Stakeholder satisfaction, as measured by 70% or above, on workshops survey. • Customer satisfaction of the overall engagement process, as measured by 70% or above score on workshop feedback.	Workshop participants were recruited on the basis of gender, age, household income and concession availability to ensure that we have a representative sample of customers. Our Reference Groups were satisfied (with an average rating of 4.5 out of 5), that AGN's approach to stakeholder engagement reached a representative group of customers. All stakeholders who attended our Draft Plan workshops were supportive of our approach to Stakeholder Engagement and agreed it was effective. Similarly, respondents agreed that the purpose of the workshop/s was appropriate, clearly communicated and understood. All stakeholders at our Final Plan Meeting felt they had the opportunity to contribute to the conversation. 93% of our Round 1 and 97% of Round 2 Customer Workshop participants agreed or strongly agreed that the workshop met their expectations.
Transparent process	• Public disclosure of details about engagement activities. • Publish on website: strategy, workshop materials, customer insights, business plans and KPIs. • Attendance by CEO at one or more workshop. • Publish Draft Plan, open for stakeholder comment. • Reference Group access to Board and management team.	Our website hosts all key documents, insights, opinions and reports, as well as provides opportunity to provide feedback and find out about ways to get involved in our engagement process. 88% of our Reference Group members believe AGN's engagement was transparent. Our CEO attended three customer workshops in Research Phase, as well as two customer workshops and three stakeholder workshops during the Implementation Phase. We received positive stakeholder feedback on his attendance. Our Draft Plan was published 5 July 2016. Senior management attended AGN Reference Group meetings and customer workshops.

[24] Origin Energy, *Submission to AGN Draft Plan for Victorian Gas Distribution Networks,* page 1. Provided at Attachment 5.8.

Customers in their feedback provided through workshop evaluation forms made the following comments on our engagement program:[25]

> *"Good to hear and see that what we had discussed previously had actually been heard and put into place in the plans."*
>
> *"I really enjoyed seeing an improvement on estimated costs, also having senior staff to talk to was great."*
>
> *"It was positive to hear that the company had listened to our feedback."*
>
> *"Pleased to see that AGN has listened to the discussion groups concerns, and tried to keep the costs down."*
>
> *"The fact that AGN have listened to what we said and even improved on suggested costs etc. has been well done."*

5.9. Summary

We believe that we have delivered an effective stakeholder engagement program to inform this Final Plan. We consider that effective engagement will assist the business to achieve our objective of submitting a plan to the AER that delivers for our customers and is capable of being accepted. Our engagement program:

- further developed and improved on our previous engagement activities, particularly through the development of and engagement on our Draft Plan;
- had strong commitment from our Executive Management Team through all phases of engagement (strategy, research and implementation);
- was supported by appropriate educational materials;
- included a broad range and number of our customers and key stakeholder groups, which was greatly facilitated by the establishment of and commitment shown by our two Reference Groups;
- provided multiple channels and opportunities for feedback to be provided on our plans, including through the further customer workshops; and
- independently captured and reported on all customer and stakeholder feedback, which has in turn been reported on in this Final Plan.

We are confident that the initiatives included in this Final Plan are underpinned by an effective stakeholder engagement program.

[25] A summary of feedback is provided at Attachment 5.12 to this Final Plan.

6. Pipeline Services

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6. Pipeline Services

6.1. Introduction

We are required to define the type and nature of pipeline services that we intend to provide to our customers over the next (2018 to 2022) Access Arrangement (AA) period. Pipeline services include:

- *Reference Services* – which are those services that are likely to be sought by a significant part of the market; and
- *Non-Reference Services* – which are those services specifically requested by customers (and are also referred to as negotiated services).

This chapter explains the services that we intend to provide over the next AA period. These proposed pipeline services are the same as those currently applying in Victoria and Albury.

6.2. Regulatory Framework

We are required by the National Gas Rules (NGR) to describe in our Final Plan the services that we intend to provide over the next AA period in accordance with the definitions above.

6.3. Stakeholder Engagement

We did not receive any specific stakeholder feedback on the services proposed in our Draft Plan (Table 6.1). This is not surprising given this is a relatively non-controversial part of our plans, reflecting in part that we are not proposing to change the services to be provided over the next AA period from that currently applying.

Table 6.1: Consideration of Stakeholder Feedback on Pipeline Services

Draft Plan Stakeholder Question	Stakeholder Feedback	Our Response to Feedback on the Draft Plan
Is there any further information you would like on the pipeline services AGN is proposing?	None received	We have provided additional information on the nature of the reference services we are proposing to apply relative to that provided in the Draft Plan.
Should AGN be changing the proposed pipeline services, if so what should we change?	None received	The proposed Pipeline Services are consistent with that outlined in the Draft Plan and with that currently applying across all our networks, including in Victoria and Albury.

Note: In this 'traffic light' table, green shading represents no change from the Draft Plan, orange shading represents a modification of the position outlined in the Draft Plan and red shading represents change from the Draft Plan.

6.4. Reference Services

Reference Services comprise Haulage Reference Services (HRS) and Ancillary Reference Services (ARS). The proposed Reference Services for the next AA period are the same as those currently applying in Victoria and Albury (see Table 6.2). The proposed Reference Services are also consistent with that recently approved by the Australian Energy Regulator for our South Australian network.[26]

Table 6.2: Victorian and Albury Reference Services

Reference Service	Description
Haulage Reference Services	
Volume Haulage Service	The delivery of gas to those customers using less than 10 terajoules (TJ) per annum. The Volume Haulage Service has two associated prices – one for residential customers and one for commercial customers. AGN will read the meters every two months as part of the Volume Haulage Service.
Demand Haulage Service	The delivery of gas to those customers using more than 10TJ per annum. There is only one price available for Demand Haulage Services and it is a capacity charge that is based on Maximum Hourly Quantity. AGN will read the meters on a monthly basis as part of the Demand Haulage Service.
Ancillary Reference Services	
Meter and Gas Installation Test	On site testing to check the measurement accuracy of a 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	Removal of a meter at a premise.
Meter Reinstallation	Reinstallation of a meter at a premise.
Special Meter Read	Reading of a meter in addition to the scheduled meter reading.

The above HRS include the transport of gas from an upstream pipeline to the customer premise, the odorisation of gas where required, the provision and maintenance of a standard metering installation, meter reading and associated data services. We will provide all services in a manner that is consistent with our obligations, including our safety obligations and the terms and conditions of access described in Chapter 15.

We believe that our proposed HRS and ARS will continue to be sought by a significant part of the market during the next AA period, and as such, propose that they continue to be provided from 1 January 2018.

[26] This reflects a long-term initiative of AGN to standardise services and terms of access across our networks.

6.5. Non-Reference Services

In certain cases a customer may require services that are different from the Reference Services, which are referred to as Non-Reference Services. These services are not sought by a significant part of the market, and as such, are not considered to be Reference Services. AGN will negotiate a price directly with the customer that is requesting a Non-Reference Service.

6.6. Summary

We intend to provide the same pipeline services that are currently provided in Victoria and Albury. These services include the volume haulage service (delivery of natural gas to residential and commercial customers) and demand haulage services (delivery of gas to large customers).

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7. Operating Expenditure

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7. Operating Expenditure

7.1. Introduction

Australian Gas Networks Limited (AGN) incurs operating expenditure (opex) in order to operate and maintain its Victorian and Albury natural gas distribution networks (the networks), respond to publicly reported gas leaks, read meters and grow the customer base. We have applied an approach to forecasting opex that is consistent with that recently used by the Australian Energy Regulator (AER) to forecast opex for our South Australian network.

This chapter outlines our approach to forecasting opex and the key drivers of forecast opex over the next (2018 to 2022) Access Arrangement (AA) period.

7.2. Regulatory Framework

The forecast of opex is required to reflect that required by a prudent distributor, acting efficiently and in accordance with good industry practice to achieve the lowest sustainable cost of providing Reference Services to our customers.[27] Any forecast or estimate must be arrived at on a reasonable basis and must represent the best forecast or estimate possible in the circumstances.[28]

7.3. Overview

Our actual opex is expected to be $330 million over the current (2013 to 2017) AA period, which is approximately $35 million (or 10%) below the allowance of $365 million that was approved by the AER (see Figure 7.1).[29, 30] This reduction is primarily driven by a reduction of costs following the change in ownership of the business in August 2014 and lower costs due to reductions in the unit cost of work delivered, which benefits are spread across our entire cost base. These benefits reflect the:

- strict cost management practices applied across our business, which practices are also incentivised by the AER's Efficiency Benefit Sharing Scheme (EBSS); and
- significant scale of our contractor APA Asset Management (APA) (the largest owner/operator of natural gas infrastructure in Australia), reflecting the ability of APA to achieve efficiencies with respect to the unit cost of work delivered.

The benefits of these lower costs have now been passed through to customers through a lower 'base year' opex that is used to forecast opex over the next AA period (see Section 7.6.1). Our actual opex in 2016 is $64 million (the base year), which is $2 million below actual opex in 2011 that was used to set prices over the current AA period.

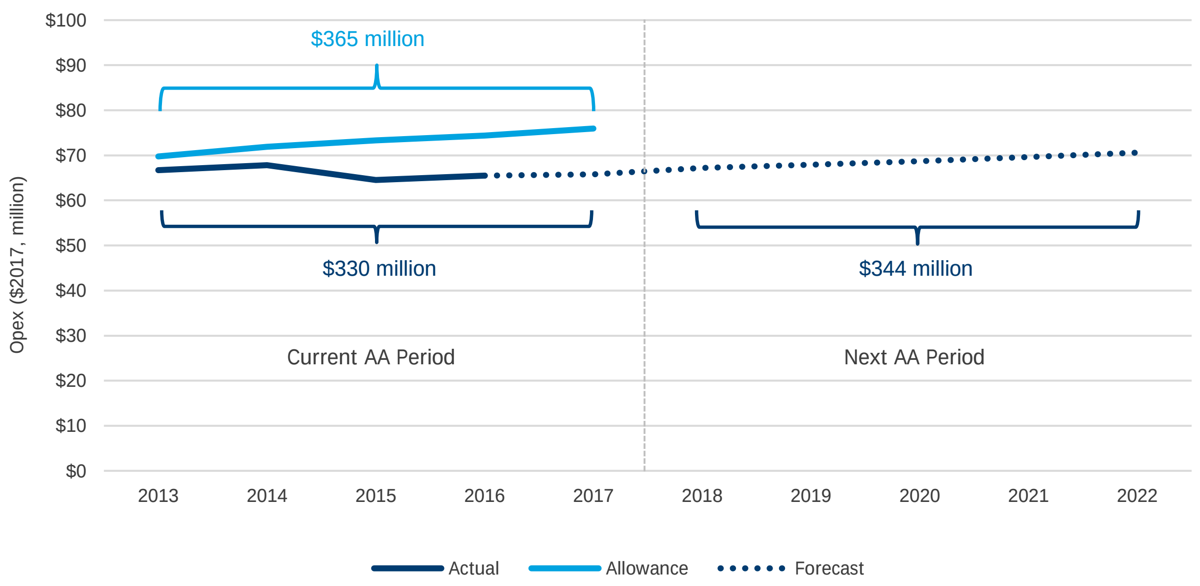
27 Consistent with Rule 91 of the NGR, as outlined in Attachment 1.1 to this Final Plan.

28 As outlined in Attachment 1.1 to this Final Plan.

29 Inclusive of debt raising costs.

30 Note: as outlined in Section 1.5 of this Final Plan, all dollars provided in this Chapter are in $2017 terms unless otherwise stated.

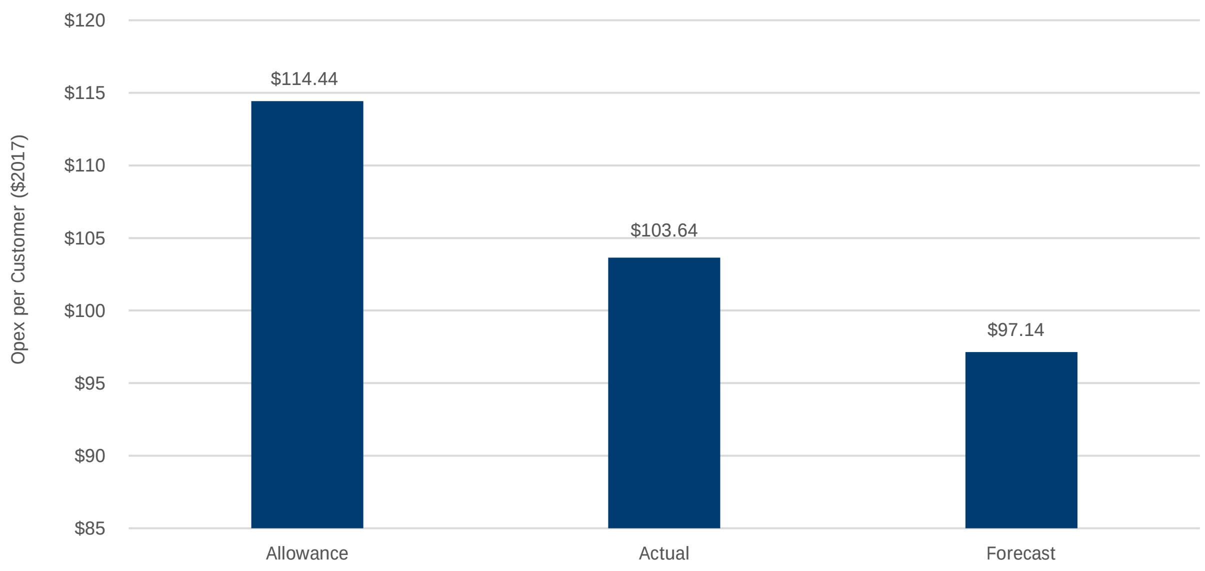
Figure 7.1: Current AA Period Actual Opex Compared to Forecast ($2017, million)



Our forecast opex over the next AA period is 4% (or $14 million) above current levels (relative to customer number growth of around 10%), reflecting increased costs associated with customer growth and changes in input costs expected over the next AA period. We have also included an initiative to expand our marketing program by $5 million over the next AA period. We have absorbed all other identified step changes (of around $4 million) into our current cost base.

Our forecast opex is $7 per customer (or 6%) lower on average over the next AA period compared to that incurred over the current AA period. Our forecast opex per customer is also $17 per customer (or 15%) lower than the opex allowances approved by the AER in the current AA period. This is shown in Figure 7.2 below.

Figure 7.2: Opex per Customer Comparison ($2017)



7.4. Stakeholder Engagement

We have reflected the outcomes of our stakeholder engagement program in our opex forecast, including the feedback around maintaining current levels of network reliability and increasing customer awareness of our business, our assets and of natural gas. We have tested how we have responded to stakeholder feedback with customers and stakeholders through:

- *stakeholder engagement on our Draft Plan* – during which we explained and discussed with stakeholders, in the context of our full proposal, our overall opex forecast and the approach taken to develop that forecast; and
- *further customer workshops* – during which customers provided feedback on our opex proposal and how we have responded to previous stakeholder feedback.

As outlined in Chapter 5 of this Final Plan, stakeholders were supportive of the manner in which stakeholder feedback had been incorporated into our proposal, including our approach to forecasting opex and our plan to expand marketing activities over the next AA period. Table 7.1 provides a summary of the key feedback received from stakeholders as it relates to questions asked in our Draft Plan and describes how we have incorporated this feedback into our Final Plan.

Table 7.1: Consideration of Stakeholder Feedback on our Opex Proposal

Draft Plan Stakeholder Question	Stakeholder Feedback[31]	Our Response to Feedback on the Draft Plan
Do you consider we have applied an appropriate approach to forecasting opex?	Stakeholders agreed with our approach of adopting AER positions from the South Australian AA review process.	Our approach to forecasting opex is consistent with that outlined in our Draft Plan (which approach is consistent with that used to forecast opex in South Australia).
Should the non-base year costs outlined in this section [of the Draft Plan] be added to our opex forecast or be absorbed by the business?	Stakeholders agreed with our decision to not seek additional funding for identified changes in costs, including in relation to opex driven by capex and step changes. Stakeholders, however, wanted assurance that doing so wouldn't compromise current service levels or result in higher expenditure in the future. Stakeholders acknowledged our decision not to apply a negative productivity adjustment, noting the outcomes of our independent expert advice on this matter and our decision to absorb certain costs in the base year.	We believe we can continue to meet our current service levels under our opex forecast in the next AA period.
Do you support our proposal to expand our marketing program over the next AA period?	Stakeholders were supportive of AGN conducting a similar marketing program to that in South Australia. Support was, however, dependent on AGN demonstrating that the benefits from marketing, including from increased demand, exceeded the costs. Stakeholders also emphasised the importance of collaborating with the other Victorian networks to deliver an efficient marketing program.	We are proposing to implement a marketing program consistent with that outlined in our Draft Plan. Further information is provided in Attachment 7.1, which outlines that the medium term benefits to customers exceed the near term costs and that we are working closely with the other Victorian gas distributors to deliver the marketing program.
Do you consider that increases in opex attributable to the growth of our networks is appropriately captured through growth in customer numbers (or should growth in throughput also be accounted for)? Should any output growth factor that is developed for gas distribution be subject to industry-wide consultation before it is introduced?	Stakeholders agreed that opex is most closely aligned with customer numbers and not throughput, noting the largely fixed-cost nature of natural gas supply. Our approach to forecasting the impact of output growth based on customer numbers was therefore considered to be reasonable.	We have calculated output growth based on a forecast of customer numbers only and have received further support for this approach from an expert adviser, which advice is provided as Attachment 7.3 to this plan.

Note: In this 'traffic light' table, green shading represents no change from the Draft Plan, orange shading represents a modification of the position outlined in the Draft Plan and red shading represents change from the Draft Plan.

31 Deloitte, *Stakeholder and Customer Feedback Report*, December 2016. Provided as Attachment 5.10 to this Final Plan.

7.5. Development of our Operating Expenditure Proposal

We have applied a 'base year roll-forward' approach to forecast opex over the next AA period. Under this approach, we adjust actual opex incurred in 2016 (the 'base year') for costs that are not included in the base year and are expected to be incurred over the next AA period, such as growth in customer numbers. As mentioned in the previous section, we have also considered the implications of our engagement program on forecast opex.

Table 7.2 summarises our approach to forecasting each component of opex as well as the implications of our engagement program and consistency with that applied by the AER for our South Australian network. This shows that the 2016 base year opex amount accounts for around 95% of our forecast opex over the next AA period.

Table 7.2: Overview of Opex Proposal ($2017, million)

Opex Component	Forecast Cost	AER SA Approved Approach?	Stakeholder Feedback and Incorporation[32]	Associated AA Documentation
2016 Base Year	322.2	Yes	Consistent with the approach approved by the AER in relation to our South Australian AA review, we have used 2016 (the penultimate year in the current AA period), as our base year. Stakeholders believed that benchmarking information supported the efficiency of our base year and as such, considered it was reasonable to use 2016 actual opex as the basis to forecast opex.	Attachments 3.1 and 3.2 Economic Insights Reports. Section 7.6.1.
Non-Base Year Opex Costs	5.1	Yes	Stakeholders were supportive of our approach to absorb opex costs associated with capex projects and step changes over the next AA period, so long as doing so wouldn't compromise current service levels. Additionally, stakeholders were supportive of AGN conducting a similar marketing program to what we already deliver in South Australia.	Attachment 7.1 Marketing Business Case. Section 7.6.2.
Input Cost Escalation	6.9	Yes	Stakeholders agreed that adopting the same approach as that used in South Australia was reasonable.	Attachment 7.2 BIS Shrapnel Forecasts. Section 7.6.3.
Output Growth	5.0	Modified	We have modified the approach to calculating output growth from that approved by the AER in relation to our South Australian AA review. We have derived an output growth measure based solely on the use of customer numbers. Stakeholders agreed that opex is most closely aligned with customer numbers and not throughput, noting the largely fixed cost nature of natural gas supply. AGN's approach to forecasting the impact of output growth was therefore considered to be reasonable.	Attachment 7.3 ACIL Allen Report. Section 7.6.4.
Productivity Growth	0.0	Yes	We have applied zero productivity growth to our opex forecast, consistent with that approved by the AER in relation to our South Australian AA review. Stakeholders acknowledged our decision not to apply the negative productivity adjustment determined by our expert adviser (which would have increased opex) and noted that AGN wasn't seeking additional funding for identified changes in opex.	Attachment 7.3 ACIL Allen Report. Section 7.6.5.
Debt Raising Costs	4.8			
Total	**344.0**		**Stakeholders commented that, at an overall level, AGN's opex proposal appeared reasonable.**	

Note: Totals may not add due to rounding.

32 Deloitte, *Stakeholder and Customer Feedback Report*, December 2016. Provided as Attachment 5.10 to this Final Plan.

7.6. Forecast Operating Expenditure

This section explains each component of our opex forecast from Table 7.2. All costs stated in this section are in $2017 terms, unless otherwise stated.

7.6.1. 2016 Base Year

We have used an estimate of our actual opex in calendar year 2016 as the base year to determine forecast opex for the next AA period. The 2016 base year is used because it reflects the most recent actual information relating to the scope and cost of providing Reference Services over the next AA period that will be available at the time the AER makes its Final Decision (which is expected to occur around November 2017, see Chapter 1, Figure 1.2).

Base year opex is necessarily an estimate as the 2016 calendar year is not yet complete, with the estimate in this plan comprising nine months of actual opex and three months of estimated opex. AGN will update this information to incorporate a full year of actual information in our response to the AER's Draft Decision.

The use of actual opex incurred in the 'base year' reflects that the majority of opex is recurrent in nature and the operation of the EBSS provides strong assurance that base year costs are efficient. This was highlighted by the AER in its recent decision for our South Australian network:

> *"AGN has been subject to [an] incentive framework for a number of access arrangement periods, including the application of an efficiency carryover mechanism for opex. In theory, AGN as a profit maximising firm should reveal its efficient costs over time, and these can be used to forecast opex into the future. Unless we have evidence that the revealed opex in a proposed base year is materially inefficient, we use the revealed costs of the service provider for our alternative opex forecast."* [33]

Our current estimate of 2016 base year opex is $64 million for both Victoria and Albury. As detailed in Chapter 3, we consider that our leading productivity performance supports the use of our estimated 2016 base year to forecast opex over the next AA period. We also note the following view expressed by the AER in its 2014 annual electricity benchmarking report:

> *"... the most significant output of distributors is customer numbers. The numbers of customers on a distributor's network will drive the demand on that network. Also, the comparison of inputs per customer is an intuitive measure that reflects the relative efficiency of distributors."* [34]

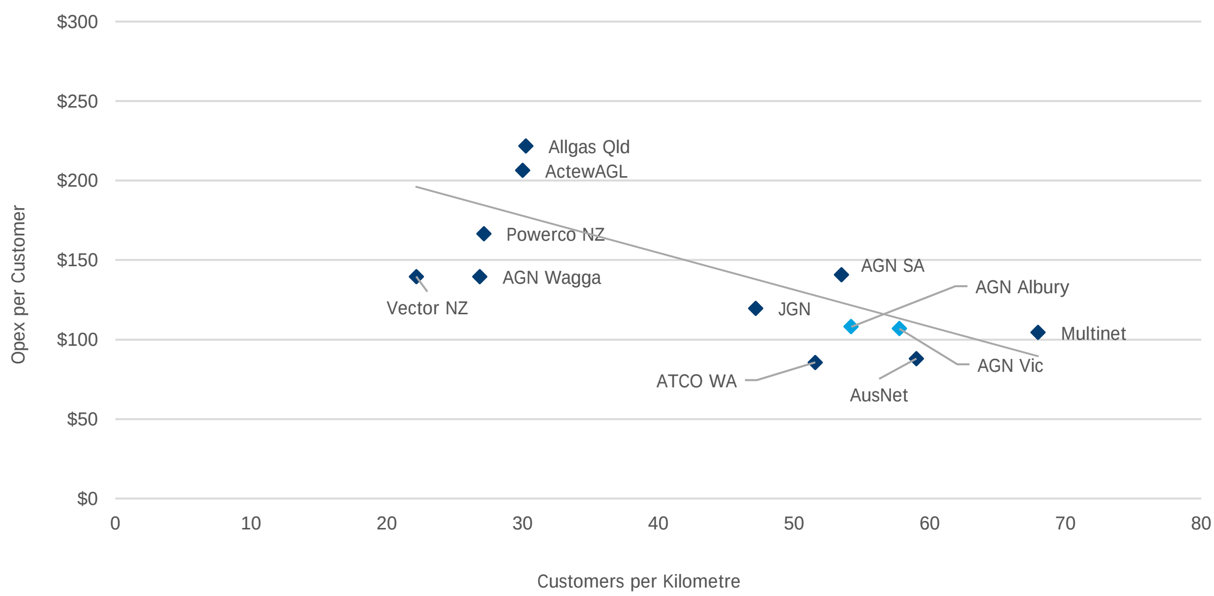
We therefore also sought expert advice on our opex per customer relative to customer density, where customer density is the total number of customers per kilometre of mains (see Figure 7.3). This shows that our Victorian and Albury opex per customer is at the lower end of the range across all gas distributors included in the sample, and that both our Victorian and Albury networks sit below the trend line of the data sample.[35]

[33] AER, *Attachment 7: Operating Expenditure | Draft Decision Australian Gas Networks 2016 to 2021*, November 2015, pages 7-14.

[34] AER, *Electricity distribution network service provider's annual benchmarking report*, November 2014, page 23.

[35] Note: In engagement activities relating to our Draft Plan, stakeholders noted that they would value additional explanation in terms of what the line in Figure 7.3 represents. This is the linear trend line as calculated based on the data sample shown in Figure 7.3.

Figure 7.3: Opex per Customer Relative to Customer Density ($2017)



Source: Based on Economic Insights, *Benchmarking Vic Gas Distribution Businesses Operating and Capital Costs Using Partial Performance Indicators*, 15 June 2016. Provided at Attachment 3.2 to this Final Plan.

Note: New Zealand (NZ), Queensland (Qld), Jemena Gas Networks (JGN), South Australia (SA), Western Australia (WA) and Victoria (Vic).

We consider that this evidence provides further support for our leading productivity performance and provides assurance that our base year opex reflects efficient costs. This view was confirmed at our stakeholder workshops, where participants agreed that our 2016 base year opex was efficient and formed a reasonable basis to forecast opex over the next AA period.

7.6.2. Non-Base Year Opex

There are certain identified activities that we intend to provide over the next AA period that are not reflected in the 2016 base year. This includes costs associated with the delivery of a particular capital project and/or a one-off or permanent ‘step’ change to business activity.

The AER indicated in its recent review for our South Australian network that increases in forecast opex for step changes should not form part of forecast opex for the following reasons:

- base year opex already includes an efficient and prudent level of expenditure;
- there is likely to be some non-recurrent expenditure in the base year (and the AER now prefers not to make adjustments to the base year);
- project costs should be offset by future productivity gains; and/or
- costs are otherwise immaterial and should be absorbed by the business.

Consistent with the above AER guidance, we have not sought to increase forecast opex in relation to the identified step changes we expect to incur during the next AA period, aside from our proposed expanded marketing program. Our decision not to increase opex for the identified step changes results in AGN absorbing approximately $5 million into our recurrent opex cost base over the next AA period, which is equivalent to achieving a 0.3% annual improvement in productivity.

We have also made a commitment in response to stakeholder feedback that our proposal to absorb these costs into our base year is on the basis of not compromising our ability to maintain current levels of service, reliability and safety over the next AA period.

7.6.2.1. Changes in Opex Absorbed into Forecast

Table 7.3 sets out the opex that is driven by our proposed capex program and the other initiatives that we do not currently provide but intend to deliver over the next AA period. The total cost of these initiatives is around $5 million over the next AA period, which costs will be absorbed into our recurrent cost base (that is, we are not seeking an increase in our opex as a result of the projects listed in Table 7.3).

Table 7.3: Step Change Projects ($2017, million)

Step Change	Cost	Description
Transmission Pipeline Modification	0.3	We are proposing a capital expenditure (capex) initiative to modify the Dandenong to Frankston and North Melbourne to Fairfield transmission pipelines in order to ensure they can be subject to internal inspections. The opex associated with this project relates to conducting the internal inspections.
Pipeline Integrity Assessment	2.0	This project aims to improve the baseline data that is needed to verify pipeline integrity in relation to some of our pipelines in Victoria.
GasNet Custody Transfer Meter (CTM) Charges	1.0	This project is to install new CTM connections in line with the expected growth of our networks. This project is required in order to comply with our regulatory obligations relating to gas delivery, metering, pressure and customer connections.
Transmission Asset Drawings Update	0.6	This project is required to rectify the current inadequacies in the technical drawings currently on file in order to ensure our compliance with relevant standards and the ongoing safety of our employees and the public.
Environment Management Plans	0.5	Energy Safe Victoria (ESV) requires AGN to maintain an Environment Management Plan relating to our Victorian assets. A new requirement from the ESV requires 'line lists' to be included in the Environment Management Plan and reviewed by the ESV every two years. An initial survey has been conducted and this project estimates the additional costs involved in maintaining the line lists and conducting an additional survey every two years.
Total	**4.5**	

7.6.2.2. Expanded Marketing Program

The only step change for which we are proposing as an increase in our efficient costs of providing services above our base year relates to our proposed expanded marketing program. We are seeking additional funding for our marketing program on the basis that it reflects a material increase in costs that are not included in our base year.

Marketing is required because natural gas is a fuel of choice, reflecting that there are readily available and low cost substitutes for all residential and most business uses of natural gas. As a result, and like most other businesses, we are required to market (or sell) the benefits of natural gas to customers. The competitive pressures faced by our business are expected to increase as a result of, for example, increasing penetration of renewable electricity and storage options.

Our marketing activities include working with appliance retailers, advertising and offering incentives (or rebates) for the connection of new appliances to the network. We currently undertake an expanded marketing program across our entire South Australian network where we are the only gas distributor. We currently deliver these marketing programs in regional areas of Victoria and Albury where we are the only gas distributor.

We have not, however, undertaken any marketing in the Melbourne metropolitan area to date because there are two other distributors in this area, which has meant that we could not market and offer rebates to customers located in our network only.

To overcome this complexity, we are proposing to coordinate marketing activities with the other two gas distributors in the next AA period, which will provide for a more effective and lower cost marketing program across all of metropolitan Melbourne.

To implement this joint marketing initiative in metropolitan Melbourne, we are proposing to increase our expenditure on marketing by $5 million over the next AA period (or by $1 million per year). As explained in more detail in Attachment 7.1, our marketing program is justified on the basis that:

- *Our proposed rebates are prudent and efficient* – the present value of the revenue earned through the additional gas appliances installed on our network (as a result of offering appliance rebates) is greater than the cost to our customers of the rebate.
- *Our proposed increase in marketing expenditure is in the long-term interests of consumers* – the increase in costs over the short-term will result in lower prices to customers in the medium to long term relative to the prices that would otherwise apply if we did not increase our marketing spend. This is because our marketing program will increase the usage of our network, which will result in our fixed costs being spread over more customers or usage.
- *An increase in our marketing program is consistent with good industry practice* – our increased marketing program is consistent with other gas distribution businesses that actively undertake marketing activities (such as Jemena Gas Networks, ATCO Gas and across all our other networks where we are the only gas distributor).[36]

Attachment 7.1 provides more detail regarding the analysis of the benefits and costs of our proposed expanded marketing program.

7.6.3. Input Cost Escalation

Our approach is consistent with that applied most recently by the AER in our South Australian AA review to escalate input costs over the next AA period, which includes applying:

- the AER preferred opex resource mix of 62% labour and 38% material costs;
- no input cost escalation to material costs; and
- an average of BIS Shrapnel and the latest available forecasts from Deloitte Access Economics to determine real labour cost escalation.[37]

The above approach results in a real (before inflation) average annual increase in opex of 0.6% over the next AA period, which is detailed in Table 7.4. Further detail is provided in Attachment 7.2 in relation to BIS Shrapnel's forecasts.

[36] Note: the marketing programs for these businesses have also been approved by the AER.

[37] Note: The latest available forecasts from Deloitte Access Economics (22 February 2016) have been provided as a part of the AER's Final Decision in relation to the Victorian electricity distribution businesses and can be accessed here: http://www.aer.gov.au/system/files/DAE-AER%20Report%2022%20Feb%202016.pdf.

Table 7.4: Weighted Input Cost Escalation Rate

Escalation Rate	Weight	2017	2018	2019	2020	2021	2022
Labour	62%	0.3%	0.8%	0.9%	1.1%	1.4%	1.5%
Materials	38%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Weighted Input Cost Escalation Rate		**0.2%**	**0.5%**	**0.6%**	**0.7%**	**0.9%**	**1.0%**

7.6.4. Output Growth

We incur additional opex as the net number of customers connected to our networks increases (referred to as output growth).

There are different ways output growth can be determined. One gas distributor recently proposed an output growth factor that is based on forecast customer numbers and throughput, which approach was accepted by the AER. We have not applied this approach as we do not believe that opex is driven by both customer numbers and throughput.

We accept that opex costs are driven by customer numbers but do not believe that increases or decreases in throughput have a direct relationship with opex. Our position is supported by the analysis conducted by ACIL Allen (provided as Attachment 7.3):

> *"… the energy throughput variable was shown to not achieve statistical significance at either the 1% or 5% levels of significance in any of the five estimated models… These results are not surprising given the empirical fact that energy throughput has been declining for the majority of gas distribution businesses over the sample period, while operating expenses have continued to increase. This suggests that energy throughput is not a key driver of increasing operating expenses for the nine gas distribution businesses under consideration and is therefore excluded as an output from the econometric specification and any subsequent calculations…"*[38]

Additionally, stakeholders agreed that opex is most closely aligned with customer numbers rather than throughput, given the largely fixed cost nature of natural gas distribution networks. Consequently, stakeholders supported the approach in our Draft Plan to forecasting the impact of output growth based on customer numbers only.

We have therefore continued to determine output growth based on the forecast growth in net customer numbers (see Chapter 13 for our demand forecasts) multiplied by the incremental cost of providing services to new customers. The approach taken to estimate the incremental cost per customer is consistent with:

- that approved by the AER to apply to our Victorian and Albury networks for the current AA period[39]; and
- the incremental cost per customer of $17 per annum (expressed in $2006) as per the 2014 Victorian Gas Distribution System Code.[40]

Our forecast output growth is set out in Table 7.5.

[38] ACIL Allen, *Opex Partial Productivity Analysis*, 20 December 2016, pages 27-28. Provided at Attachment 7.3 to this Final Plan.

[39] AER, *Access Arrangement Draft Decision: Envestra Draft Decision – Part 2*, September 2012, page 258.

[40] Essential Services Commission of Victoria, *Gas Distribution System Code*, October 2014, page 44.

Table 7.5: Output Growth

Incremental Cost per Customer	2018	2019	2020	2021	2022	Total
Net Customer Growth	8,176	13,101	13,249	13,472	13,695	**61,692**
Incremental Cost per Customer ($2017)	23.0	23.1	23.1	23.2	23.3	
Total ($2017, million)	**0.4**	**0.7**	**1.0**	**1.3**	**1.6**	**5.0**

Note: Totals may not add due to rounding.

7.6.5. Productivity Growth

In applying the 'base year roll-forward' approach, we have considered whether there should be an adjustment to capture any potential future efficiency gains that could be made by the business.

We have forecast productivity using the same cost function analysis relied upon by the AER to forecast productivity in the electricity industry. This produces a declining forecast of productivity growth for our networks over the next AA period. If applied, this productivity growth forecast would result in an increase to our opex forecast for the next AA period. We have therefore decided not to apply this productivity factor.[41]

We also note:

- our leading productivity performance, with our Victorian network consistently generating the highest productivity levels when compared against those gas distributors included in the sample (see Chapter 3 for more detail); and
- our decision to absorb certain non-base year costs into our recurrent opex forecast (see Section 7.5), which results in an implied productivity adjustment of around 0.3% per year.

7.7. Summary

Forecast opex for the next AA period is $344 million, which is 4% above actual opex incurred in the current AA period (see Table 7.6 and our opex forecast model, Attachment 7.4). Importantly, customer numbers are forecast to be 10% above the current AA period, indicating that opex on a per customer basis is forecast to be less over the next AA period compared to current levels (see Figures 7.2 and 7.4).

This forecast is largely based on the 2016 base year, which consists of nine months of actual opex and three months of estimated opex (and will be updated once the 2016 calendar year has concluded). Our 2016 base year opex, which accounts for around 94% of total forecast opex, reflects the most recent actual information relating to the scope and cost of providing services over the next AA period.

Our leading productivity performance supports the use of our 2016 base year to forecast opex over the next AA period. We have adjusted base year costs for customer growth, changes in labour costs and for our expanded marketing program, which is aimed at lowering prices to existing customers over the medium term.

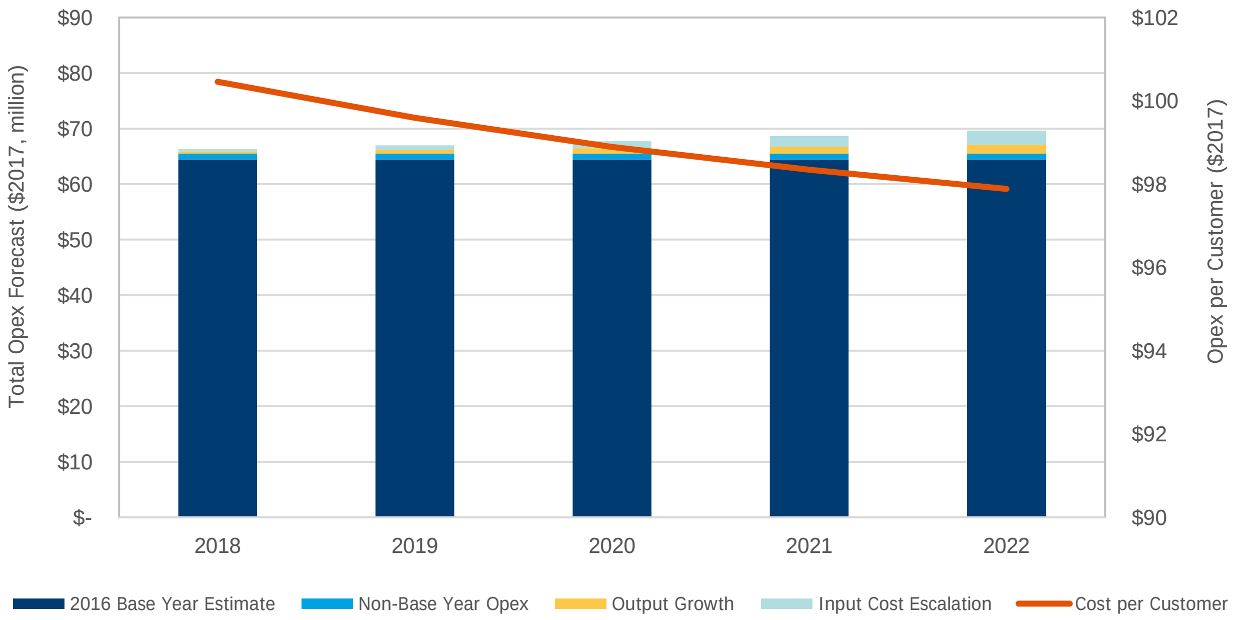
[41] We also have concerns over the extent that this type of analysis can be relied upon. To this end, Acil Allen noted in their report that their analysis should only be used for indicative purposes, reflecting their concerns over (for example) the comparability of data between businesses and the relatively small sample size.

Table 7.6: Opex Forecast Summary ($2017, million)

Opex Component	2018	2019	2020	2021	2022	Total
2016 Base Year Estimate	64.4	64.4	64.4	64.4	64.4	322.2
Non-Base Year Costs	1.0	1.0	1.0	1.0	1.0	5.1
Output Growth	0.4	0.7	1.0	1.3	1.6	5.0
Input Cost Escalation	0.4	0.8	1.3	1.9	2.5	6.9
Debt Raising Costs[42]	0.9	0.9	1.0	1.0	1.0	4.8
Total	**67.2**	**67.9**	**68.7**	**69.6**	**70.6**	**344.0**

Note: Totals may not add due to rounding.

Figure 7.4: Composition of Forecast Opex



[42] Note: Debt Raising Costs have been calculated consistent with the AER's Post-Tax Revenue Model.

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8. Capital Expenditure

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8. Capital Expenditure

8.1. Introduction

Australian Gas Networks Limited (AGN) incurs capital expenditure (capex) in order to connect new customers to the Victorian and Albury natural gas distribution networks (the networks) and to ensure the ongoing safe and reliable supply of natural gas to our customers. As with operating expenditure (opex), our approach to forecasting capex has largely been based on the approach approved by the Australian Energy Regulator (AER) for our South Australian network.

This chapter outlines our forecast capex over the next (2018 to 2022) Access Arrangement (AA) period, including our forecasting approach and the key drivers of forecast capex.

8.2. Regulatory Framework

Our forecast capex is required to reflect that of a prudent distributor, acting efficiently and in accordance with good industry practice to achieve the lowest sustainable cost of providing Reference Services to our customers. Our proposed capex must also satisfy various additional criteria, such as maintaining and improving safety, maintaining network integrity, ensuring compliance with our obligations, meeting network demand and/or ensuring the revenue generated from a project exceeds the associated costs.[43]

Any forecast or estimate must be arrived at on a reasonable basis and represent the best forecast or estimate possible in the circumstances.[44]

8.3. Overview

Our actual capex is expected to be $591 million over the current (2013 to 2017) AA period, which is approximately $14 million (or 2%) below the allowance of $606 million that was set by the AER.[45] Items of note include:

- *Mains Replacement* – we have spent approximately $18 million less than that approved by the AER on mains replacement over the current AA period, whilst still being on track to deliver the approved volume of kilometres. This reflects that we have completed less complex areas than initially anticipated.
- *Information Technology (IT)* – we have commenced a program of nationalising our IT capabilities, and as such, have spent approximately $4 million more than that approved by the AER over the current AA period. This has been in order to bring our capabilities to an appropriate level that is more in-line with other energy distributors in Australia.

Our forecast capex is 6% (or $36 million) below current levels, which reduction is driven mainly by the completion of our mains replacement program by the end of the next AA period (see Figure 8.1). Other key components of our capex forecast include the ongoing nationalisation of our IT capabilities and the forecast connection of around 16,000 new customers to our network each year.

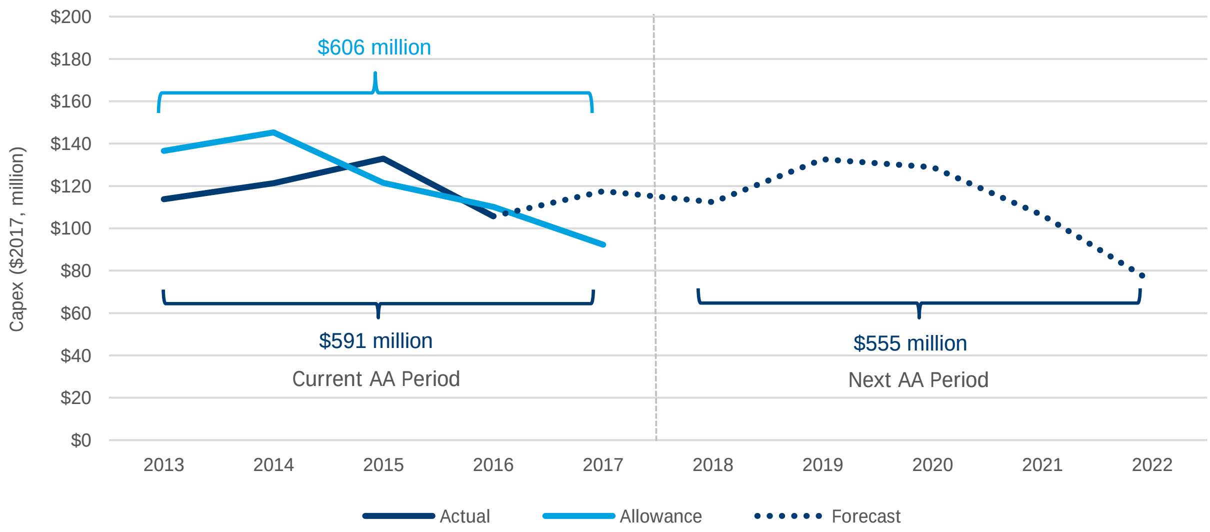
43 Consistent with Rule 79 of the NGR, as outlined in Attachment 1.1 to this Final Plan.

44 Consistent with Rule 74 of the NGR, outlined in Attachment 1.1 to this Final Plan.

45 Note: as outlined in Section 1.5 of this Final Plan, all dollars provided in this Chapter are in $2017 terms unless otherwise stated.

As detailed in the remainder of this chapter, the majority of our capex relates to maintaining the reliability of the networks, maintaining and improving the safety of the networks and connecting new customers to the networks. Our forecast capex is consistent with a ‘stay in business’ proposal.

Figure 8.1: Comparison of Actual Capex to Forecast Capex ($2017, million)



8.4. Stakeholder Engagement

We have reflected the outcomes of our stakeholder engagement program throughout our capex proposal, particularly in regard to the initiatives that are aimed at improving network safety and maintaining current levels of reliability.[46] More specifically, we are proposing to:

- maintain and improve network safety primarily by completing our mains replacement program, which received particularly strong support through our stakeholder engagement program and from the safety regulator, Energy Safe Victoria (ESV);
- maintain current levels of supply reliability by completing several key network augmentation projects, including completing our long-term project to reinforce supply to customers connected on the outer eastern network down to the Mornington Peninsula;
- improve our ability to communicate with customers by improving our digital capabilities; and
- introduce a program of installing thermal safety devices to all new and replacement meters in bushfire risk areas, following strong support for this initiative in our customer workshops.

We have tested how we have responded to feedback from our customers and key stakeholders through:

- *stakeholder engagement on our Draft Plan* – which set out, in the context of our overall proposal, our forecast capex as a whole, the approach taken to developing this forecast and the key projects to be undertaken; and
- *further customer workshops* – during which customers provided feedback on our whether we captured feedback from the initial customer workshops accurately and whether we had responded to that feedback appropriately.

[46] Further information on our stakeholder engagement program is provided in Chapter 5 of this Final Plan.

As outlined in Chapter 5 of this Final Plan, stakeholders were generally supportive of our approach to forecasting capex and of the manner in which stakeholder feedback had been incorporated into our proposal. At times, stakeholders asked AGN to provide additional information compared to the Draft Plan, which information has been provided in this Final Plan. Table 8.1 summarises key stakeholder feedback on our capex proposal against the questions asked in our Draft Plan and explains how this feedback has been incorporated into our Final Plan.

Table 8.1: Consideration of Stakeholder Feedback on our Capex Proposal

Draft Plan Stakeholder Question	Stakeholder Feedback	Our Response to Feedback on the Draft Plan
Do you consider we have applied an appropriate approach to forecasting capex?	Stakeholders agreed with AGN's approach of adopting AER positions from the South Australian AA review process, including the approach to forecasting unit rates.[47]	Our approach to forecasting capex is consistent with that outlined in our Draft Plan and that approved by the AER for our South Australian network.
	When discussing our meter replacement program, stakeholders were interested in 'smart' metering, although understood that the benefits of this technology might not outweigh the costs.[39]	Consistent with the Draft Plan, AGN is not proposing to implement any smart metering in the next AA period. As outlined in Chapter 11, AGN is proposing a Network Innovation Allowance to provide funding to investigate such activities.
	AGN should provide further information on: • how new connection expenditure compares with other networks;[48] • how IT expenditure has been allocated across networks;[40] and • the impact that a successful marketing program has on growth, and therefore capex.[39]	This Final Plan proposal contains additional information on all aspects of our capex proposal, including growth, IT and marketing. We consider our connection costs are likely to compare favourable with the other distributors.
Do you support the completion of our mains replacement program?	Customers, stakeholders and the ESV were supportive of AGN completing its mains replacement program.[39]	Our proposed mains replacement program is consistent with that outlined in the Draft Plan.
Do you support our risk assessment approach to delivering the volume of mains to be replaced, including our dedicated engagement with ESV on this issue?	Stakeholders agreed that detailed engagement with ESV was appropriate.[39] We have engaged with ESV, who has written to AGN advising of its support for our proposed mains replacement program.	We are proposing to complete our mains replacement program over the next AA period, which program is consistent with that set out in our Draft Plan and endorsed by ESV. [49]
Have we appropriately considered and incorporated the outcomes of our stakeholder engagement program?	Customers agreed that we had appropriately incorporated their feedback into our Plans.[39] Both stakeholders and customers noted that we had provided adequate opportunity to comment/input into our Plans.[39]	As described in Chapter 5, we have incorporated stakeholder and customer feedback throughout our Plans.

Note: In this 'traffic light' table, green shading represents no change from the Draft Plan, orange shading represents a modification of the position outlined in the Draft Plan and red shading represents change from the Draft Plan.

[47] Deloitte, *Stakeholder and Customer Feedback Report*, December 2016. Provided as Attachment 5.10 to this Final Plan.

[48] Origin Energy, *Submission to AGN Draft Plan for Victorian Gas Distribution Networks*, 22 August 2016. Provided as Attachment 5.8 to this Final Plan.

[49] ESV, *Letter to Australian Gas Networks*, 21 December 2016. Provided at Attachment 8.9 to this Final Plan.

8.5. Development of the Capital Expenditure Program

This capex forecast has been developed using a ‘bottom-up’ forecasting method specific to each capex driver category. Our capex forecast has had regard to the following processes and principles:

- the ‘bottom-up’ approach used for each capex driver category consists of either:
  - a unit rate multiplied by volume; or
  - discrete projects detailed in individual plans or business cases (see Attachment 8.6);
- where possible, we have utilised the approach approved by the AER in our recent South Australian AA review process, including by basing forecast capex on either:
  - the most recent actual information available, which information reflects revealed efficient expenditure; or
  - the most recent tender/contract information available, which information reflects the market-tested costs that will be incurred over the next AA period;
- forecast capex is consistent with our overarching business plans (see Section 8.5.1), which plans describe the robust planning, approval and governance processes that apply to both actual and forecast capex; and
- forecast capex is based on the considerable expertise of AGN and its contractor APA Asset Management (APA) and reflects the strict cost management processes that apply between both businesses.

The above, combined with our leading productivity performance (see Section 3.2.1), ensures that actual and forecast capex satisfies the relevant requirements of the National Gas Rules (NGR), including that capex is prudent, efficient and consistent with good industry practice to achieve the lowest sustainable cost for our customers.

Stakeholders also supported our approach to forecasting capex, particularly our approach of adopting the most recent positions of the AER for our South Australian networks.[50]

8.5.1. Overarching Business Plans

Our capex proposal for the next AA period has been developed pursuant to several key business plans. These plans govern the scope, timing and approach to undertaking investment/upgrade of critical business information systems, asset replacement and augmentation works that are necessary to ensure ongoing network safety, that our regulatory obligations are met and that our service performance is maintained.

The plans aim to achieve an optimal balance between safety, service levels, reliability and cost. More specifically:

- *the Asset Management Plan (AMP)* (Attachment 8.1) – which describes how our plans are used to drive asset management strategies that are consistent with good industry practice;
- subordinate to the AMP are the following:
  - *the Distribution Mains and Services Integrity Plan (DMSIP)* (Attachment 8.2) – which outlines AGN’s approach to managing the integrity of our mains and services and provides the basis for the forecast replacement of mains over the next AA period;

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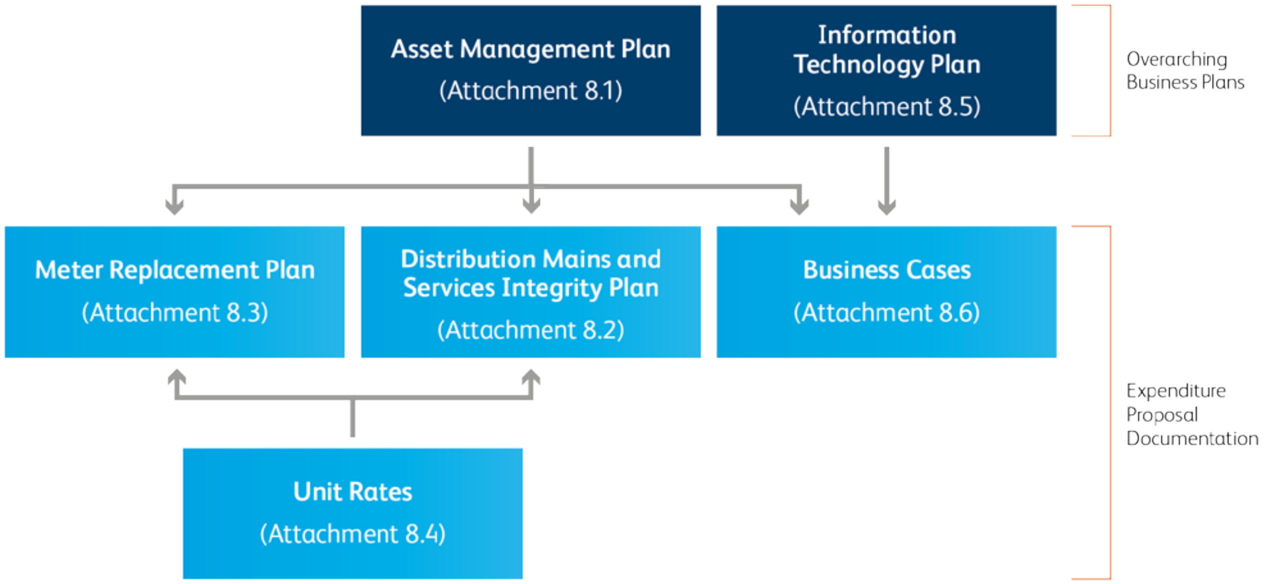
[50] Deloitte, *Stakeholder and Customer Feedback Report*, December 2016. Provided as Attachment 5.10 to this Final Plan.

  - *the Meter Replacement Plan* (Attachment 8.3) – which details our compliance obligations and how this drives the forecast volume of meters to be replaced over the next AA period; and
  - *the Unit Rates Forecast* (Attachment 8.4) – which details our approach to deriving unit rates for the next AA period;
- additionally, *the IT Plan* (Attachment 8.5) – which provides the framework for the development and implementation of key business systems across AGN.

In addition to the above, we have prepared detailed Business Cases (Attachment 8.6) relating to specific capex requirements for the next AA period. These Business Cases are subordinate to the AMP and IT Investment Plan. The relationship between these documents is detailed in Figure 8.2 below.

Figure 8.2: Overarching Business Plans



8.6. Forecast Capital Expenditure

Table 8.2 provides an overview of the forecast associated with each capex driver category, including our forecasting method and response to stakeholder feedback. This section provides further detail on our capex forecasts over the next AA period. All dollar terms stated in this section regarding the capex driver categories reflect direct costs only (i.e. exclusive of overheads and input cost escalation).

Table 8.2: Overview of Capex Proposal Over the Next AA Period ($2017, million)

Capex Driver Category	Forecast Cost	Comment	Cost Forecasting Method	Stakeholder Feedback[51]	Associated AA Documentation
Mains Replacement	154	We will complete our mains replacement program in the next AA period, resulting in the replacement (and upgrade) of the low pressure parts of the networks including in the Melbourne Central Business District (CBD).	Unit Rate x Volume (km)	Customers and stakeholders strongly supported the mains replacement program. 95% of customers indicated they were prepared to pay more on their gas bill for AGN to complete this work. Customers also indicated this was their highest priority initiative.	Final Plan Section 8.6.1 Attachment 8.2 DMSIP Attachment 8.4 Unit Rates Forecast
Growth	174	We expect to connect approximately 16,000 new customers each year over the next AA period, thereby supporting the ongoing growth of the networks.	Unit Rate x Volume (customer numbers)	Customers were concerned with potential price increases – connecting new customers to the network lowers prices to all of our existing customers.	Final Plan Section 8.6.2 Attachment 8.8 Capex Model Attachment 8.4 Unit Rates Forecast
Information Technology	64	We are continuing to implement a program of nationalising IT capabilities across our Victorian and Albury networks, consistent with the program accepted by the AER in relation to our South Australian AA.	Discrete Business Case Projects	Customers would like access to more information from AGN and favour digital channels. Customers are also supportive of initiatives that improve the safety of the networks.	Final Plan Section 8.6.3 Attachment 8.5 IT Plan Attachment 8.6 Business Cases Attachment 8.7 KPMG IT Expenditure Benchmarking
Meter Replacement	33	We will continue to periodically replace residential and commercial meters in order to maintain compliance with Australian Standard 4944.	Unit Rate x Volume (meter numbers)	Customers are supportive of initiatives that improve the safety and reliability of the networks.	Final Plan Section 8.6.4 Attachment 8.3 Meter Replacement Plan Attachment 8.4 Unit Rates
Augmentation	28	We have identified areas of our network that require augmentation works in order to maintain current levels of reliability of supply to customers.	Discrete Business Case Projects	85% of customers supported paying more on their gas bill to support network reliability.	Final Plan Section 8.6.5 Attachment 8.1 AMP Attachment 8.6 Business Cases
Telemetry	1	We are proposing three small projects in order to expand our telemetry network to regional towns and replace assets in poor condition.	Discrete Business Case Projects	Customers are supportive of initiatives that improve the safety and reliability of the networks.	Final Plan Section 8.6.6 Attachment 8.1 AMP Attachment 8.6 Business Cases
Other Assets	35	We have identified several refurbishment and replacement programs required to be undertaken over the next AA period, as well as modification of our transmission pipelines to enable more effective condition monitoring and certain other stay-in-business projects.	Discrete Business Case Projects	Customers are supportive of initiatives that improve the safety and reliability of the networks. 94% of customers supported the installation of thermal safety devices.	Final Plan Section 8.6.7 Attachment 8.1 AMP Attachment 8.6 Business Cases
Sub-Total	**489**				
Overheads and Escalation	66				Final Plan Sections 8.6.8 and 8.6.9 Final Plan Chapter 7
Total	**555**				

51 Customer feedback as detailed in the Deloitte Customer Insight Report (Attachment 5.7) and the Deloitte Stakeholder and Customer Feedback Report (Attachment 5.10).

8.6.1. Mains Replacement

The provision of a safe and reliable supply of natural gas is the most important driver of business performance. An integral part of ensuring public safety is our DMSIP, which sets out the strategy for the replacement of ageing/deteriorating mains on our network.

Our long-term mains replacement program, which commenced in 2003, involves the removal of low-and-medium-pressure cast iron (CI), unprotected steel (UPS) and polyvinyl (PVC) mains from our networks. We have demonstrated a strong commitment to delivering this program, including through the planned completion of the full 696 kilometres of mains replacement allowed for in the current AA period.

Over the next AA period we are planning to complete our low-pressure mains replacement program and to replace other mains determined to be at risk. This work was strongly supported by stakeholders and was considered to be the highest priority initiative at our customer workshops. Importantly, and consistent with stakeholder feedback, we have engaged with the safety regulator, ESV, on our DMSIP. The ESV noted in a letter to AGN that they have:

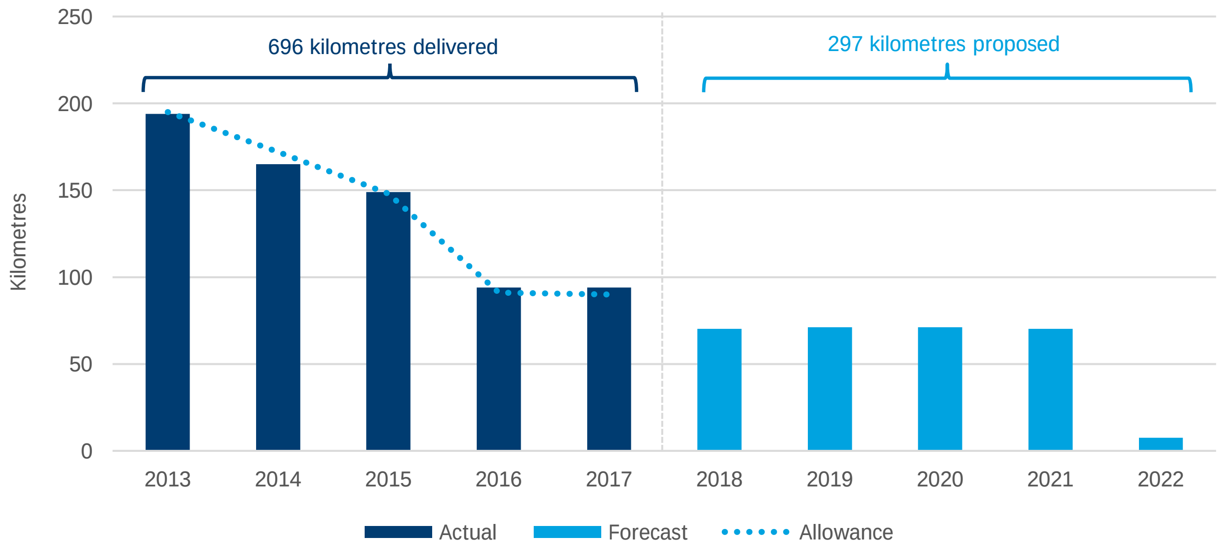
> *"… reviewed the DMSIP as a basis for managing the integrity of distribution mains and services in AGN's Victorian gas distribution network. The DMSIP outlines the timing, scope and cost of proposed risk mitigation strategies, including mains and services replacement."*[52]

The ESV has endorsed our proposed mains replacement program, noting that:

> "… *ESV supports the proposed mains and services replacement program outlined in AGN's DMSIP, being the replacement of 297km of CI, UPS, PVC and HDPE [High Density Polyethylene] mains."*[53]

Consistent with this, we are forecasting to spend $154 million on replacing 297 kilometres of mains over the next AA period, which is less than half the volume of mains replaced over the current AA period (see Figure 8.3).

Figure 8.3: Mains Replacement Program Volumes



52 ESV, *Letter to Australian Gas Networks*, 21 December 2016. Provided at Attachment 8.9 to this Final Plan.

53 Ibid.

This section explains the risk assessment, volume and cost of our mains replacement program. The forecast cost is based on determining the number of kilometres of mains that require replacement over the next AA period and multiplying these kilometres by a unit rate that has been based on either recent tender information or historic cost information (which was also based on competitively tendered rates).

8.6.1.1. Forecast Volume of Mains Replacement

The volume of mains replacement has been determined by applying the relevant Australian/New Zealand Standard 4645 (AS/NZS 4645). The standard requires an assessment of the consequence and likelihood of an identified risk occurring and then sets out requirements around addressing the risk. Any risks that are rated as ‘extreme’, ‘high’, or ‘intermediate’ must be reduced to ‘low’ or ‘negligible’ (or as low as reasonably practicable) as soon as possible.

Our risk assessment has identified that:

- There are no mains in our networks rated as ‘extreme’ risk.
- There are 25 kilometres of CI and UPS mains located in the Melbourne central business district (CBD) that are rated as ‘high’ risk. All of these mains will be replaced over the next AA period.
- There are 32 kilometres of medium pressure CI and UPS trunk mains throughout the network rated as ‘high’ risk. These mains will be decommissioned or replaced over the next AA period.
- The majority of CI, UPS and PVC mains are also rated as ‘high’ risk. There are 192 kilometres of these mains that will be replaced over the next AA period.
- Some of the CI, UPS and PVC mains and high density polyethylene (HDPE) mains over 35 years old are rated as ‘intermediate’ risk. There will be 634 kilometres of these mains in our network at the end of the current AA period. We are proposing to replace only 35 kilometres of these mains during the next AA period, consisting of:
  - 25 kilometres of PVC mains integrated within the low pressure network in low density suburbs (LDS);
  - 7 kilometres of the oldest HDPE mains in our network; and
  - 3 kilometres of HDPE mains less than 35 years old (rated as ‘low’ risk), to be replaced as part of a sampling program to gather information to inform whether a possible future replacement program is required.

As such, our forecast volume of mains replacement over the next AA period ensures:

- all of the mains rated as ‘high’ risk are replaced during the next AA period;
- the risk associated with mains identified as ‘intermediate’ risk is managed by either:
  - replacing the mains where it is prudent and efficient to do so; or
  - continuing to mitigate the risk by other means, such as managing the operating pressure, undertaking leak surveys and commencing an in-line camera inspection program; and
- investigative work and a sampling program will be conducted in order to inform the approach to any future replacement program of ageing HDPE pipe.

Included in our mains replacement forecast is a relatively smaller cost that is associated with service renewals. These assets are replaced as we deliver our mains replacement program due to the safety and cost benefits of doing so, rather than as a stand-alone activity. This is consistent with current practice.

We consider that the above replacement program is consistent with our obligations under the relevant standard, including prudently managing risk on our network to as low as reasonably practicable, as illustrated in Table 8.3. Importantly, the ESV has endorsed the volume of mains to be replaced over the next AA period as set out in our DMSIP. Specifically, ESV has advised that:

> *"ESV is satisfied that AGN has in its development of the DMSIP:*
>
> - *proposed a mains and services replacement program which has been developed and prioritised via appropriate risk–based analysis;*
> - *assessed the condition of assets and risks associated with mains and services, utilising the qualitative risk assessment framework in accordance with the appropriate standards, being AS/NZS 4645 and AS2885.1;*
> - *utilised asset integrity performance indicators and data such as leak rate analysis to demonstrate that CI/UPS and PVC mains (which represent only 4% of the distribution network) account for almost 70% of mains leaks;*
> - *clearly and appropriately assessed and ranked CI, UPS mains and PVC mains as 'high risk';*
> - *identified appropriate options to mitigate risks associated with CI, UPS mains and PVC mains and has demonstrated the most effective way of reducing the risk is to replace all CI, UPS and PVC mains; and*
> - *indicated that AGN will continue to maintain rapid leak rate response, conduct scheduled leakage surveys, monitor odorant levels and maintain operating pressures as low as possible* as a way to monitor ongoing integrity issues.
>
> *On this basis, ESV supports the proposed mains and services replacement program outlined in AGN's DMSIP, being the replacement of 297km of CI, UPS, PVC and HDPE mains. However, ESV is not in a position to assess the financial requirements of the proposed program."* [54]

Further detail is provided in our DMSIP, which is set out in Attachment 8.2. The following section discusses the derivation of the unit rates for undertaking the mains replacement program.

[54] ESV, *Letter to Australian Gas Networks*, 21 December 2016. Provided at Attachment 8.9 to this Final Plan.

Table 8.3: Mains Risk Treatment Approach and Resultant Risk Rating

Asset Category	As at End of Current AA Period:		Risk Treatment Approach	To Be Replaced Next AA Period:	
	Kilometres	Risk Rating		Kilometres	Risk Rating
Low Pressure CI/UPS in the CBD	25	High	Replace as soon as possible	25	Not applicable
Low Pressure PVC in the CBD	12	Intermediate	No additional risk treatment proposed (six month leak surveys in place)	0	Intermediate
Low Pressure steel in the CBD	7	Low		0	Low
Medium Pressure CI/UPS Trunk Mains	32	High	Replace or decommission as soon as possible	32	Not applicable
Low Pressure CI/UPS in HDICS	96	High	Replace as soon as possible	96	Not applicable
Low Pressure PVC in HDCIS	85	High	Replace as soon as possible as part of CI/UPS replacement program	85	Not applicable
Low Pressure CI/UPS in LDS	11	High	Replace as soon as possible	11	Not applicable
Low Pressure PVC in LDS	25	Intermediate	Replace as soon as possible as part of CI/UPS replacement program	25	Not applicable
High Pressure HDPE over 35 years old	597	Intermediate	3km sampling program and 7km end of life	7	Intermediate
High Pressure HDPE less than 35 years old	2,480	Low	No additional risk treatment proposed	3	Low
High Pressure Polyethylene	4,330	Low	No additional risk treatment proposed	0	Low
Total as per Risk Assessment				**285**	
Medium Pressure Trunk Mains	Not applicable	Not applicable	Construction of new trunk mains to support new mains	12	Not applicable
Total as per Mains Replacement Program				**297**	

8.6.1.2. Forecast Cost of Mains Replacement

To estimate the cost of the mains replacement program, we have developed a unit rate for each main type and assessed the costs that might result from certain locational characteristics where the mains are to be replaced. Our forecast unit rates are based on and supported by the outcomes of our competitive tender processes. More specifically:

- where the works planning process is at the stage where the tender for the work during the next AA period has commenced, and tendered rates are available, those market-tested rates have been adopted;
- where work packages are similar to the work subject to the tender process referred to in the above point, the market-tested unit rates from comparable tenders have been adopted;
- where adjustments to tendered rates are made, these are based on actual variations experienced from prior work packages;
- where tendered unit rates for comparable packages of work are not available, historical actual unit rates for comparable work have been adopted; and
- where work is not comparable to available tendered rates or historical actual unit rates, clear and robust assumptions have been made to support forecast expected variations by work package.

We consider that our reliance on the outcomes of competitive tenders and actual costs incurred ensures our forecast capex is a best estimate and is consistent with the lowest sustainable cost of replacing the required volume of mains over the next AA period. The approach taken to determine the mains replacement unit rates is consistent with that applied in our recent South Australian AA review process. Further detail on our unit rates is provided in Attachment 8.4.

8.6.1.3. Summary

Our proposed mains replacement program ensures that network risk is prudently managed in a manner that is consistent with the relevant industry standards, our regulatory obligations and good industry practice. Our proposal will complete our mains replacement program, which commenced in 2003, thereby improving the safety of the network. Our reliance on competitively tendered outcomes and historic cost information ensures the cost of the program is efficient.

The completion of our mains replacement program received strong support in our customer and stakeholder workshops. Importantly, ESV has endorsed the proposed volume of mains replacement, stating that we have applied the relevant standard in an appropriate manner to determine the volume of mains to be replaced (see Table 8.4). Our mains replacement capex accounts for around 30% of our total capex over the next AA period.[55]

[55] 30% of total capex including overheads and cost escalation.

Table 8.4: Mains Replacement Forecast ($2017, million, direct costs only)

Program	2018	2019	2020	2021	2022	Total
General Trunk Replacement	2.1	2.1	2.1	1.6	0.3	**8.3**
Block Replacement (HDICS)	20.3	20.3	20.3	20.3	-	**81.3**
Block Replacement (LDS)	3.4	3.4	3.4	3.4	-	**13.5**
CBD Block Replacement	6.1	6.1	6.1	6.3	6.4	**31.1**
CBD Trunk Replacement	-	2.0	2.0	-	-	**3.9**
HDPE Replacement	1.1	1.1	1.1	1.1	1.1	**5.6**
Decommissioned Trunk Replacement	1.3	1.3	1.3	1.3	-	**5.1**
Piecemeal Replacement	0.3	0.3	0.3	0.3	-	**1.1**
Services Replacement	0.8	0.8	0.8	0.8	0.8	**3.7**
Total Replacement	**35.4**	**37.4**	**37.4**	**35.0**	**8.6**	**153.7**

Note: Totals may not add due to rounding.

8.6.2. Growth

Growth in customer numbers assists to lower prices to existing customers by spreading the largely fixed costs of operating the networks across a larger customer base. Growth capex relates to the costs required to facilitate new customer connections to our networks.

Our growth capex is driven by the number of new customers we expect to connect to the networks over the next AA period (which is discussed in Chapter 13), as well as any large network extensions that are required to facilitate those connections. Consistent with stakeholder feedback received on our Draft Plan, we have ensured that the estimated impacts of our proposed marketing program have been incorporated into our growth capex volume forecast.[56]

We have completed several major extensions of our network over the current AA period to the growth areas of Merrifield, Koo Wee Rup and Wandong-Heathcote Junction. We are not aware of any further network extensions that are required over the next AA period. Our growth capex forecast is therefore focused on the cost of connecting customers to existing areas of our network, including to the new areas mentioned above.

Our growth capex forecast has been determined by multiplying the forecast volume of new meters, services and mains by the relevant unit rates (as outlined in Attachment 8.4) associated with those new connections, which costs include:

- *Meters* – the historic actual average cost of installing and commissioning a meter at the customer site;
- *Services* – the average cost of providing a service (or inlet) from our mains to the customer meter; and

[56] Deloitte, *Stakeholder and Customer Feedback Report*, December 2016. Provided as Attachment 5.10 to this Final Plan.

- *Mains* – the average cost of extending our network to connect the new customer.

The total growth capex over the next AA period is $174 million, which accounts for around 36% of our total capex over the next AA period (see Table 8.5).[57]

Table 8.5: Growth Forecast ($2017, million, direct costs only)

	2018	2019	2020	2021	2022	Total
Growth Forecast	35.0	34.2	34.5	35.1	35.6	**174.3**

Note: Totals may not add due to rounding.

8.6.3. Information Technology

We are required to handle substantial amounts of information on a daily basis, including information relating to customer connections and disconnections, managing network repairs and meter reading and billing. This volume of activity requires ongoing investment in systems that link together to allow the high volume of data to flow between systems. This will ensure full system functionality to manage critical business processes and to satisfy retail market rules.

We have initiated a national program of work in the current AA period to replace our old state-based IT systems, which are over 10 years old and are no longer supported by the appropriate vendor nor able to be updated to prevent system security vulnerabilities. New enterprise equivalents servicing all five jurisdictions in which we operate are being implemented.

The key benefits of our national IT program include improved safety and operational performance by implementing standard systems across our network. Considerable progress has been made towards the nationalisation of our IT systems and infrastructure over the current AA period. This includes the installation of our enterprise asset management (EAM) system, which supports standard national processes across all five Australian jurisdictions in which AGN operates.

We are proposing to continue with this national IT program over the next AA period. The forecast IT investment for the next AA period is required to:

- complete the nationalisation program of work that commenced in the current AA period and was approved by the AER for our South Australian network;
- mitigate the risks associated with our core operating systems;
- enable the effective and efficient delivery of services to our customers; and
- ensure compliance with regulatory obligations (for example, the Retail Market Procedures).

A failure to complete the nationalisation program of work in the next AA period will limit the benefits from investments made in the current AA period (including in our other networks), increase the risk of non-compliance with relevant regulatory obligations, lead to customer and business interruptions and potentially public safety issues with the corresponding adverse financial and reputational consequences.[58]

Our current and forecast IT spend comes after a long period of lower than sustainable investment. We engaged an expert adviser to compare our actual IT spend over the previous (2008 to 2012)

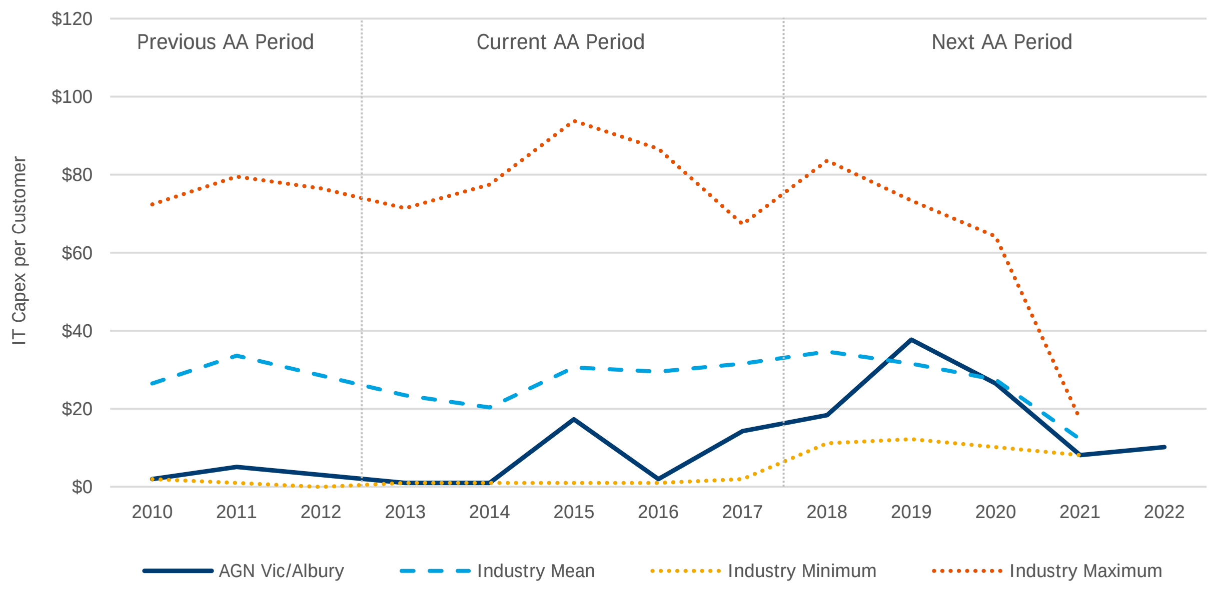
57 36% of total capex including overheads and cost escalation.

58 Costs for this national program are apportioned to each region based on the number of customers we serve in our Victorian and Albury networks in order to develop a cost estimate for each project. More specifically, the cost allocation percentages used to apportion the project costs are 51.35% Victoria and 1.79% Albury, based on customer numbers as at 31 December 2015.

and current AA periods and our forecast IT spend over the next AA period against a sample of around 20 other Australian utilities.

The analysis shows that our IT capex per customer is at or below the sample average over the entire 15-year period and consistent with the minimum IT capex per customer over the past 10 years (see Figure 8.4; further detail is provided in Attachment 8.7). This finding was consistent across all performance measures included in the sample.

Figure 8.4: IT Capex per Customer ($2017)



Source: Based on KPMG, *Information Technology Cost Benchmarking Report*, December 2016. Provided at Attachment 8.7 to this Final Plan.

The IT projects we are proposing to deliver over the next AA period in our Victorian and Albury networks are the same as those accepted by the AER for our South Australian network. Given our program of nationalisation, should we not be provided with funding to complete the Victorian and Albury program, the success and future benefits of the program as a whole, including in South Australia, would not be achieved.

The IT projects we are proposing to implement over the next AA period are described further in Table 8.6.

Table 8.6: IT Projects ($2017, million, direct costs only)

IT Project	Cost	Approved in SA?	Summary
Applications Renewal	22.5	Yes	This ongoing project ensures application systems for the Metering and Billing System, Telemetry System, GIS and Enterprise Asset Management System are updated to ensure their ongoing reliability. This project is required to perform upgrades on existing IT assets and does not involve their replacement.
Geographical Information Systems	16.5	Yes	This project provides for an upgrade to the GIS, which manages all geographic data associated with our networks (that is, the GIS maps the location of our network infrastructure). This project will mitigate a significant business risk associated with our currently unsupported GIS application and integrate the GIS into the broader EAM suite of IT applications. Implementation of this new system will ensure the ongoing safe operation of our networks so that our employees and the public can continue to access reliable information regarding the location of our assets (for example, through the Dial Before You Dig facility).
Business Intelligence	11.3	Yes	This project will provide improved information and reporting across AGN by utilising data from the disparate IT applications that are used within the business. This project will provide a toolset that will improve data quality, streamline reporting effort and allow greater access to information for optimised decision making.
Mobility Integration	10.6	Yes	This project provides for the mobile integration of resources across our networks. This includes improving network performance by automating current paper-based and manual processes through the use of mobile devices and integrated processes.
Infrastructure Renewal	1.3	Yes	This infrastructure renewal project relates to the upgrade of desktop infrastructure and telephony infrastructure.
Digital Capabilities	1.4	Yes	This project develops a range of digital capabilities aimed at delivering a customer service experience consistent with the delivery of services by other distributors (and businesses more generally). This project is consistent with our findings that customers would like to access more information from AGN through digital channels.
Total	**63.5**		

Note: Totals may not add due to rounding.

We consider this expenditure is consistent with our stakeholder feedback regarding initiatives that maintain the reliability and improve the safety of our networks and also feedback regarding increased visibility and accessibility. Additionally, in our workshops on the Draft Plan, stakeholders were supportive of our proposed IT capex, noting that the AER had already approved these national IT projects in our recent South Australian review.[59] Our IT proposal remains unchanged since the Draft Plan.

Our total forecast IT capex is $64 million over the next AA period, which accounts for around 12% of total capex.[60] Further detail is provided in Attachment 8.5 (IT Investment Plan), Attachment 8.7 (KPMG IT Expenditure Benchmarking) and Attachment 8.6 (Business Cases).

[59] Deloitte, *Stakeholder and Customer Feedback Report*, December 2016. Provided as Attachment 5.10 to this Final Plan.

[60] 12% of total capex including overheads and cost escalation.

Table 8.7: IT Projects ($2017, million, direct costs only)

IT Projects	2018	2019	2020	2021	2022	Total
Applications Renewal	4.7	3.4	4.7	3.5	6.1	**22.5**
Geographical Information Systems	-	11.3	5.0	0.2	-	**16.5**
Business Intelligence	2.6	5.1	3.4	0.1	-	**11.3**
Mobility Integration	2.6	3.2	3.3	1.4	-	**10.6**
Infrastructure Renewal	0.9	0.5	-	-	-	**1.3**
Digital Capabilities	0.7	0.6	-	-	-	**1.4**
Total	**11.5**	**24.2**	**16.5**	**5.2**	**6.1**	**63.5**

Note: Totals may not add due to rounding.

8.6.4. Meter Replacement

We have a regulatory obligation under the *National Measurement Act 1960* (Commonwealth), the Victorian Gas Distribution System Code and the New South Wales *Gas Supply (Safety and Network Management) Regulation 2013* to manage the integrity of meters and ensure they operate within a prescribed tolerance band for metering accuracy. We are required therefore to carry out periodic meter changes (PMCs) to test the accuracy of meters and replace meters when the accuracy of their measurements falls outside the prescribed tolerance band. Our obligations and processes are reported annually to the AER.

To forecast the amount that will be spent on meter replacements in the next AA period, consideration must be given to:

- the number of domestic and commercial PMCs that are expected to be required in each year of the AA period, which is a function of a range of factors, including the age of the meters, the condition of the meters and the types of meters in service; and
- the cost of carrying out the PMCs (e.g. the costs of procuring new and refurbished meters, installing the meters, carrying out the testing and associated activities), which we have established through competitive tender processes and are reflected in the domestic and commercial PMC unit rates set out in our Unit Rates Report.

Using information on the age of our meter fleet, the types of meters and the most recent test results, we have estimated that:

- 152,621 domestic meter replacements will be required in the next AA period; and
- 7,055 commercial meter replacements will be required in the next AA period.

Applying the domestic and commercial meter replacement unit rates to the forecasts set out above, we have estimated that the meter replacement program will cost $33 million over the next AA period, which represents around 8% of total capex.[61] For more detail regarding our meter

[61] 8% of total capex including overheads and cost escalation.

replacement forecast, please refer to Attachment 8.3 (the Meter Replacement Plan) and Attachment 8.4 (the Unit Rates Report).

Table 8.8: Forecast Meter Replacement ($2017, million, direct costs only)

	2018	2019	2020	2021	2022	Total
Residential	5.2	5.2	5.2	2.7	2.7	**20.8**
Commercial	2.5	2.5	2.5	2.5	2.5	**12.4**
Total Forecast	**7.6**	**7.6**	**7.6**	**5.1**	**5.1**	**33.2**

Note: Totals may not add due to rounding.

8.6.5. Augmentation

Gas flows through our network are continually reviewed to ensure there is adequate capacity and pressure to meet customer demand. Network modelling, based on pressure and flow data and forecast customer growth, indicates those parts of the network that are likely to require reinforcement (or augmentation). This process results in projects that are aimed at ensuring there is sufficient:

- capacity to ensure that our network is capable of continuing to meet the demand for services, particularly in areas of high growth;
- capacity to ensure the availability of high pressure gas to support the systematic and planned replacement of mains (as explained earlier in Section 8.6.1); and
- protection of the networks from over-pressurisation, which can occur if key pressure regulator facilities fail to operate as designed.

The key projects are described in Table 8.9 and aim to maintain the reliability and security of supply to customers. These projects are consistent with stakeholder feedback for AGN to maintain reliability levels. More specifically, when tested with customers, around 85% supported paying more on their bill to maintain network reliability.[62]

We also note that at this stage, we have excluded costs associated with augmentation of the Morwell to Tramway Road pipeline from our forecasts as the delivery of this project is contingent on an ESV decision regarding the condition of the pipeline. This decision is due early to mid-2017, so we expect that we will be able to confirm the need for this project at the time of our Revised AA Proposal.

We also note that we have recently received a letter from the Australian Energy Market Operator (AEMO) regarding a reduction in connection pressure at Sale. We are currently reviewing the implications of this request and will provide a Business Case to the AER in early 2017. We have included this letter as Attachment 8.10.

[62] As outlined in Chapter 5, in our initial customer workshops, 85% of participants supported the Dandenong-Crib Point project and 86% supported paying more to implement a range of other smaller augmentation projects. Customers also supported our integration of these results into our Plans, as demonstrated in our secondary customer workshops.

Table 8.9: Key Augmentation Projects ($2017, million, direct costs only)

Augmentation Project	Cost	Description
Dandenong-Crib Point	14.0	The Dandenong to Crib Point Pipeline was originally constructed in 1966 and delivers natural gas to around 110,000 customers from the Dandenong City Gate down to the Mornington Peninsula. Capacity issues on this main has resulted in the staged construction of a parallel main, with the final stage now required. This project is to provide capacity to meet ongoing customer growth and maintain network reliability. This project received 85% support from workshop participants.
Cranbourne High Pressure Augmentation	8.8	Ongoing connections in and around Cranbourne will require network reinforcement to support customer growth while maintaining network reliability to existing customers.
City Gate and Customer Transfer Meter (CTM) Upgrades	2.4	Natural gas is delivered into our network from transmission pipelines through city gates (or custody transfer meter stations). Major works at three entry points (Berwick, Lindrum Road and Sale) are required in the next AA period to ensure appropriate gate station capacity.
Other	2.8	Various smaller projects to maintain the integrity of services and reliability of our networks.
Total	**28.0**	

Note: Totals may not add due to rounding.

Overall, we are proposing augmentation capex of $28 million over the next AA period, which accounts for 6% of total capex.[63] For more detail regarding our proposed augmentation projects, refer to Attachment 8.6, which contains our proposed Business Cases. For completeness, we have included in this Attachment a Business Case for the Morwell to Tramway Road augmentation project.

Table 8.10: Key Augmentation Projects ($2017, million, direct costs only)

Augmentation Projects	2018	2019	2020	2021	2022	Total
Dandenong-Crib Point	3.7	6.9	3.5	-	-	**14.0**
Cranbourne High Pressure Augmentation	0.9	1.2	3.3	1.7	1.7	**8.8**
City Gate and CTM Upgrades	0.5	0.5	0.4	0.8	0.4	**2.4**
Other	0.7	0.8	0.3	1.0	-	**2.8**
Total	**5.7**	**9.3**	**7.4**	**3.5**	**2.1**	**28.0**

Note: Totals may not add due to rounding.

[63] 6% of total capex including overheads and cost escalation.

8.6.6. Telemetry

We rely on telemetry or Supervisory Control and Data Acquisition (SCADA) for the real-time monitoring of network conditions and, in some cases, for the remote control of gas flows and pressures to optimise system performance and maximise safety. Over the next AA period, AGN is proposing to spend $1 million on telemetry projects, in order to:

- more effectively manage monthly meter reading of large customer sites and the resulting data; and
- extend the SCADA network to regional towns and certain fringe points of the network.

This expenditure is consistent with the finding that customers are supportive of initiatives that maintain reliability and improve the safety of our network. Our telemetry capex forecast of around $1 million accounts for 0.2% of total capex.[64] For more detail regarding our proposed telemetry projects, refer to Attachment 8.6, which contains our proposed Business Cases.

Table 8.11: Telemetry Forecast ($2017, million, direct costs only)

	2018	2019	2020	2021	2022	Total
Telemetry	0.3	0.3	0.3	0.3	0.1	**1.2**

Note: Totals may not add due to rounding.

8.6.7. Other Assets

There are various other items of capex that do not fall into a specific category but are still required to provide services to our customers (and are required to be estimated based on our bottom-up approach to forecasting capex). These projects include the following:

- *Ongoing refurbishment and replacement of assets ($10 million)* – assets such as city gate valves and commercial meter sets can have their useful lives extended by undertaking refurbishment works, while items such as SCADA remote telemetry units, cathodic protection, regulators, valves and flow correctors require replacement;
- *Modification of the Dandenong to Frankston and Dandenong to North Melbourne transmission pipelines ($14 million)* – to enable more effective condition monitoring via internal inspection to detect potential steel defects;
- *Upgrades to plant and equipment ($4 million)* – stay-in-business replacement of necessary tools and equipment used by our field staff to undertake their duties, based on the average cost of replacing these tools in recent years;
- *Refurbishment of Key Depots ($4 million)* – refurbishment of two key depots servicing the Victorian and Albury networks; and
- *Bushfire Preparedness ($3 million)* – while 94% of workshop participants supported the installation of thermal safety devices to new and replacement meters in all areas, we are proposing to restrict the program to bushfire prone areas only, consistent with the scope of works approved by the AER in South Australia.[65] We consider that this roll-out achieves a reasonable balance between managing residual risk and cost.

[64] 0.2% of total capex including overheads and cost escalation.

[65] AER, *Final Decision Australian Gas Networks Access Arrangement – Attachment 6 – Capital Expenditure*, May 2016.

Our Other Assets capex is around $34 million over the next AA period, which accounts for around 7% of our total capex.[66] For more detail regarding these proposed projects, please refer to Attachment 8.6, which contains our proposed Business Cases.

Table 8.12: Other Assets Forecast ($2017, million, direct costs only)

	2018	2019	2020	2021	2022	Total
Other Assets	4.7	6.5	11.5	8.1	4.0	34.8

Note: Totals may not add due to rounding.

8.6.8. Input Cost Escalation

We have applied the AER's preferred approach to applying input cost escalation over the next AA period, as explained in Chapter 7 of this Final Plan.

8.6.9. Overheads

Overhead costs are applied to forecast capex in order to recover general business costs that are not accounted for in the direct capex forecasts. These overhead costs include the costs associated with operations management and administration, network planning and system design, procurement and fleet, technical assurance, network engineering and other support costs such as finance and human resources.

We have applied the same approach used by the AER for our South Australian network to ensure consistency across our business. This approach involves:

- splitting historic overhead costs into identified overhead categories (such as operations and maintenance, technical assurance and network engineering);
- identifying the proportion of these overhead category costs attributable to fixed or variable overhead costs;
- calculating an average fixed overhead cost incurred by AGN over the 2013 to 2015 period; and
- calculating the average percentage of variable overhead costs out of total capex over the 2013 to 2015 period and applying this percentage to total forecast capex over the next AA period.

Our total overheads forecast for the next AA period is the sum of the forecast fixed and variable components calculated above. This results in overheads of $57 million over the next AA period.

For more detail regarding our approach to forecasting overheads, please refer to Attachment 8.8 Capex Forecasting Model.

8.7. Summary

Forecast capex for the next AA period is around $555 million, which is 6% (or $36 million) below actual capex expected to be incurred over the current AA period (see Figure 8.1).

The key driver of our capex forecast is the completion of our mains replacement program, which includes replacing mains in the Melbourne CBD. Our mains replacement program is a continuation

[66] 7% of total capex including overheads and cost escalation.

of a long-term program of work and is key to maintaining and improving network safety. Other key drivers of our capex program include:

- *growth capex* – which accounts for 36% of total capex and relates to connecting new consumers to our networks; and
- *IT* – which accounts for 12% of total forecast capex and relates to the continuation of the national program of work that was initiated in the current AA period.

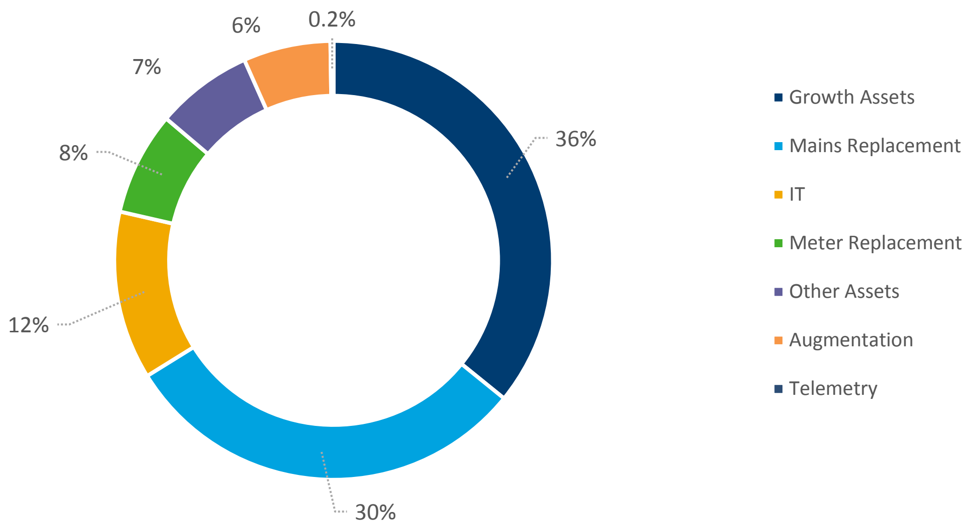
Our proposed capex is consistent with meeting our regulatory obligations and with the feedback received through our stakeholder engagement program, particularly around maintaining reliability and improving safety. Our capex forecast is set out in Table 8.13 and the composition of our program in Figure 8.5.

Table 8.13: Breakdown of Capex Forecast ($2017, million)

Capex Driver Category	2018	2019	2020	2021	2022	Total
Mains Replacement	35.4	37.4	37.4	35.0	8.6	**153.7**
Growth Assets	35.0	34.2	34.5	35.1	35.6	**174.3**
IT	11.5	24.2	16.5	5.2	6.1	**63.5**
Meter Replacement	7.6	7.6	7.6	5.1	5.1	**33.2**
Augmentation	5.7	9.3	7.4	3.5	2.1	**28.0**
Telemetry	0.3	0.3	0.3	0.3	0.1	**1.2**
Other Assets	4.7	6.5	11.5	8.1	4.0	**34.8**
Escalation	0.6	1.3	2.0	2.6	2.4	**9.0**
Overheads	11.5	11.9	11.8	11.4	10.8	**57.3**
Total	**112.3**	**132.6**	**128.9**	**106.3**	**74.8**	**555.0**

Note: Totals may not add due to rounding.

Figure 8.5: Composition of Forecast Capex (inclusive of cost escalation and overheads)



9. Capital Base

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9. Capital Base

9.1. Introduction

Australian Gas Networks Limited's (AGN's) capital base reflects the value of past investments that we have made in our Victorian and Albury networks but not yet recovered from our customers. The current value of our capital base is around $1.6 billion (nominal). We are required to adjust our capital base for capital expenditure (capex), disposals, depreciation and inflation using actual information over the current (2013 to 2017) Access Arrangement (AA) period and forecast information over the next (2018 to 2022) AA period.

This chapter discusses how we have made those adjustments for the current and next AA periods.

9.2. Regulatory Framework

We are required to adjust our capital base to reflect actual/forecast capex (net of any amounts contributed by our customers), inflation and depreciation. We are also required to make certain other adjustments to our capital base, such as to remove the value of any assets that we have sold or to reflect the reuse of redundant assets in the current AA period (which adjustments are, however, not relevant to either the current or next AA periods).

Our forecast of depreciation is required to be set:

- so that our prices vary over time in a way that promotes the efficient growth of the services provided by our business (which services were explained in Chapter 6);
- so that our assets are depreciated over the economic life of that asset (or group of assets);
- to allow for changes in the expected economic life of a particular asset (or group of assets);
- so that an asset is depreciated only once; and
- to allow for our reasonable needs for cash flow to cover our costs.

Furthermore, any forecast or estimate used in our Final Plan must be arrived at on a reasonable basis and must represent the best forecast or estimate possible in the circumstances.

9.3. Stakeholder Engagement

We engaged with our stakeholders on several key aspects of our approach to determining the value of our capital base, including on our forecast capex (which is discussed in Chapter 8), inflation and depreciation. In relation to inflation, stakeholders:

- noted that there was merit in both an approach to determining forecast inflation that relies on the forecasts and targets set by the Reserve Bank of Australia (RBA) and one based on market information;
- were interested in ways to remove forecast risk; and
- considered the approach to forecasting inflation was a key issue that needed to be resolved as part of this regulatory process.

In relation to depreciation, stakeholders supported our approach to determining regulatory depreciation, including aligning the economic and technical life of the low pressure assets that are scheduled for replacement by the end of the next AA period.

Key stakeholder feedback on our capital base is set out in Table 9.1.

Table 9.1: Consideration of Stakeholder Feedback on our Capital Base

Draft Plan Stakeholder Question	Stakeholder Feedback[67]	Our Response to Feedback on the Draft Plan
Do you agree that the value of low pressure mains should be removed from the capital base to reflect the completion of our low-pressure mains replacement program? Do you agree with our proposal to depreciate these assets over five years, such that they are fully depreciated when the low-pressure mains have been replaced?	Stakeholders supported the approach taken by AGN to determine regulatory depreciation. In particular, stakeholders supported aligning the economic and technical life of the low-pressure assets scheduled for replacement at the end of the next AA period. It was noted that the alignment of economic and technical lives of the low-pressure assets could occur while still delivering a price cut to customers.	We are seeking to align the economic and technical lives of the low pressure mains that are scheduled to be replaced at the end of the next AA period. This approach is consistent with stakeholder feedback, the National Gas Rules (NGR) and previous regulatory treatment of these assets by the Australian Energy Regulator (AER).
Do you consider that the RBA-based approach will produce better forecasts of inflation relative to the market-based approach? Are there any other approaches to forecasting inflation that should be used/considered?	Stakeholders considered both the RBA approach (preferred by the AER) and the market-based approach (preferred by AGN) had merit. Stakeholders considered the RBA as a reputable independent source but noted the market-based approach more closely aligned with both the information used to set the rate of return and with actual inflation. Stakeholders wanted to ensure that inflation risk would not be borne by consumers under a market-based approach. Stakeholders suggested alternative methods to deal with inflation, including by not adjusting the capital base for actual inflation and forecasting inflation over a five-year period and not a 10-year period. Stakeholders considered this to be a key issue that needed to be resolved over the next AA period.	We have provided additional information in this Final Plan that addresses certain concerns raised by the AER in our South Australian AA review process in relation to the market based approach. We are keen to further discuss this issue with the AER and stakeholders with a view to ensuring that we are adopting the best estimate of inflation over the next AA period. To this end, we note the AER has recently indicated it intends to undertake dedicated engagement on inflation, which process we will participate in. Consistent with our general regulatory strategy, we have applied the AER preferred approach to estimating inflation pending further discussion with the AER and stakeholders during this review process.
Do you have any other comments regarding our approach to adjust our capital base over the current and next AA periods?	Stakeholders considered the adjustment of the capital base to be a largely mechanical matter that was governed by the NGR.	We consider that our approach to adjusting the capital base is consistent with the NGR, as explained in this chapter.

Note: In this 'traffic light' table, green shading represents no change from the Draft Plan, orange shading represents a modification of the position outlined in the Draft Plan and red shading represents change from the Draft Plan.

9.4. Capital Base as at 1 January 2018

We have adjusted (or rolled-forward) our capital base as at 1 January 2012[68] for actual capex (net of customer contributions) and inflation and for forecast depreciation over the current AA period

[67] Deloitte, *Stakeholder and Customer Feedback Report*, December 2016. Provided as Attachment 5.10 to this Final Plan.

[68] 1 January 2012 reflects the last date whereby actual information was used to adjust the capital base.

(we have previously accepted the AER preference to use forecast depreciation when adjusting the capital base).[69] No assets have been made redundant or have been disposed of over the current AA period.

Table 9.2 shows the adjustments we have made to our capital base over the current AA period. The "*funding adjustment*" in the below table reflects the interest that we did not receive as a result of actual capex in the last year of the previous AA period (i.e. 2012) being above the forecast used for that year.[70] Rolling forward the capital base with actual 2012 capex as well as making the associated "*funding adjustment*" is consistent with both rule 77(2)(a) and clause 4.12 of the current (2013 to 2017) AA.

The closing value of the capital base forms the opening capital base for the next AA period and is shown in Table 9.2 below

Table 9.2: Roll Forward of the Regulatory Asset Base 2013 to 2017 ($nominal, million[71])

	2013	2014	2015	2016	2017
Opening Capital Base	1,158.0	1,244.7	1,341.2	1,438.2	1,506.7
Less Depreciation	41.3	45.4	51.1	55.0	58.4
Plus Conforming Net Capex	103.1	113.2	128.0	104.8	120.7
Plus Actual Inflation	25.0	28.7	20.2	18.6	36.0
Plus 2012 Capex Adjustments	-	-	-	-	6.2
Plus Funding Adjustment	-	-	-	-	2.2
Closing Value	**1,244.7**	**1,341.2**	**1,438.2**	**1,506.7**	**1,613.5**

Note: Totals may not add due to rounding.

9.5. Capital Base as at 31 December 2022

This section discusses the forecast adjustments that we have made to the capital base over the next AA period.

9.5.1. Capital Expenditure

Our forecast capex was discussed in Chapter 8 and is set out in Table 9.3. Our forecast capex has been allocated to the same asset categories used to adjust our capital base. We note that the capex rolled into the capital base includes an amount equal to half a year of return in the year the capex is incurred (and is therefore different to our forecast capex in Chapter 8). This adjustment is made by the AER to account for the fact that we do not earn a return on capex in the year it is incurred.

69 We have used forecast information for 2016 and 2017 as actual information is not yet available.

70 The estimated 2012 capex was $106 million, which was $7 million below actual capex of $113 million for that year.

71 Note: Dollars expressed in nominal terms incorporate the impact of forecast inflation.

Table 9.3: Forecast Capex for the Next AA Period ($nominal, million)

	2018	2019	2020	2021	2022
Mains and Services	79.8	86.7	87.6	84.7	53.6
Meters	16.2	16.3	16.8	14.8	16.0
Buildings	-	-	-	-	-
SCADA	0.3	0.3	0.3	0.3	0.2
Computer Equipment	13.4	28.6	20.1	6.7	8.5
Other Assets	5.5	7.6	14.0	10.4	5.6
Equity Raising Costs	2.1	-	-	-	-
Total Capex	**117.3**	**139.5**	**138.9**	**116.9**	**83.8**

Note: Totals may not add due to rounding.

Note: Supervisory Control and Data Acquisition.

9.5.2. Forecast Depreciation

We have continued to apply the straight line approach to determine forecast depreciation. In doing so, we have applied the same asset lives that were approved by the AER for the current AA period (as shown in Table 9.4).

Table 9.4: Summary of Lives Used to Calculate Depreciation

Asset Category	Standard Useful Life (years)
Mains and Services	60
Meters	15
Buildings	50
SCADA	15
Computer Equipment	5
Other Assets	15
Low Pressure Mains and Associated Services	5

In determining forecast depreciation for the next AA period, we have applied the approach used by the AER to set depreciation in respect of forecast capex for the current AA period (which is referred to as the 'year-by-year' tracking approach). The 'year-by-year' tracking approach closely reflects the life of the asset and was also used by the AER in its recent decisions for the South Australian and Victorian electricity distributors. [72]

We are seeking to ensure that the value of our low-pressure mains and services have been fully depreciated given our plans to complete our mains replacement program by the end of the next AA period (see Section 8.6). This is to ensure that the technical (or operational) life of these assets is the same as the economic life of the assets, where the former reflects the actual asset life while the latter reflects the assumption used in adjusting the capital base.

As noted in Section 9.2, forecast depreciation can be adjusted to reflect changes in the expected life of an asset. Our proposed adjustment to depreciation is consistent with this requirement. Our adjustment is also consistent with other decisions made by the AER where the technical life of an asset no longer matches the economic life of the asset. For example, the AER has recently decided to adjust depreciation in respect of:

- the same low pressure mains replaced by both of the other Victorian gas distributors;[73] and
- various assets that were determined by the Victorian Bushfire Royal Commission as requiring replacement in respect of one of the Victorian electricity distributors.[74].

Stakeholders at our workshops on the Draft Plan supported the approach taken by AGN to determine regulatory depreciation. In particular, stakeholders supported aligning the economic and technical life of the low-pressure assets scheduled for replacement at the end of the next AA period and noted that this could occur while still delivering a price cut to customers.

We engaged Incenta to confirm the appropriateness of adjusting our depreciation to account for the completion of our mains replacement program over the next AA period. Incenta stated that:

> *"In our view – and consistent with the AER's decisions as summarised above – an adjustment to depreciation is consistent with the requirements of the National Gas Rules and Law. In particular, we conclude that adjusting depreciation in this context:*
>
> a. *when considered against the National Gas Objective – would be likely to promote efficiency by aligning price with costs, and also promote intergenerational equity by avoiding a circumstance where future generations would be required to pay for both the replaced and replacing assets*
>
> b. *when considered against the National Gas Rules – the combination of Rules 89(b) and Rule 89(c) require assets to be depreciated over their economic lives and for depreciation to be adjusted to reflect changes in such lives, which encourages precisely the outcome AGN is proposing.*
>
> c. *in addition - the fact that AGN's reference tariffs for the next access arrangement period even after the adjustment to depreciation are expected to fall materially compared to current levels means that the adjusted depreciation is unlikely to adversely affect the efficient growth in the market for services (and so be neutral towards Rule 89(a))."*[75]

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[72] The year-by-year approach better aligns the forecast depreciation for assets with technical life of those assets relative to alternate approaches. Expert advice recommends adopting the year-by-year tracking approach. For instance, see Incenta, *Calculation of Depreciation – Review of the AER's Approximate Calculator: Citipower, Powercor and Jemena Electricity Networks,* July 2015 or HoustonKemp, *Analysis of Different Approaches to Calculating Remaining Lives: Report for SA Power Networks,* June 2015.

[73] AER, *Draft Decision, Multinet Access Arrangement 2013 to 2017*, Attachment 4, page 119, November 2012; and AER, *Draft Decision, AusNet Access Arrangement 2013 to 2017,* Part 2 Attachments page 504 to 207, November 2012.

[74] AER, *Preliminary Decision, AusNet Services Distribution Determination 2016 to 2020,* pages 5-13 to 5-17, October 2015.

[75] Incenta, *Low Pressure Mains and Services Depreciation*, December 2016. Provided at Attachment 9.1 to this Final Plan.

Incenta have estimated the residual value of the low-pressure mains and associated services, as at 1 January 2018, to be $89 million.[76] We have depreciated these residual values equally over each year of the next AA period. There could be an argument to further increase the rate of depreciation on the basis that:

- our low-pressure mains replacement program will be largely completed by 2021 (which is year 4 of the next AA period, thereby implying a four-year depreciation period); and
- so that the value of those assets already replaced is depreciated in year one of the next AA period (2018), although there may be practical issues with this approach.

On balance, we consider a five-year depreciation period achieves the objective of ensuring that the low-pressure mains and services are fully depreciated at the time they are replaced in our network. Table 9.5 shows our forecast straight-line depreciation, which includes the adjusted depreciation of our low pressure mains and services.

Table 9.5: Forecast Straight-line Depreciation, 2018 to 2022 ($nominal, million)

	2018	2019	2020	2021	2022
Straight-line Depreciation	80.1	88.0	93.3	90.0	96.3

9.5.3. Inflation

The estimate (or forecast) of expected inflation is a critical element in determining our total revenue (and hence prices). As explained earlier, estimated inflation is used to adjust the capital base over the next AA period. This estimate is later updated for actual inflation when adjusting the capital base in the subsequent (2023 to 2027) AA period (consistent with the adjustment for actual inflation explained in Section 9.4 to our capital base made now in respect of the current AA period).

The estimate of inflation is also used in determining the total revenue that we can recover (and hence the prices we can charge). This is reflected by the methodology that the AER uses to determine our total revenue, which relies on inflation to determine the following two (building block) costs:

- *Return on capital* – which is calculated by multiplying a nominal rate of return (see Chapter 10) by the nominal capital base determined in this section (where a nominal value includes the impact of inflation); and
- *Regulatory Depreciation* – which is calculated by deducting from forecast straight-line depreciation (see Table 9.5) the expected inflation adjustment applied to the capital base.

With regard to the second point, the AER removes inflation in determining regulatory depreciation to essentially remove the additional compensation for inflation in determining the return on capital, which arises from multiplying a nominal rate of return by a inflation adjusted capital base (referred to as a ‘double count’ of inflation).

As explained in more detail in Attachment 9.2, the AER’s current approach is to address the ‘double count’ of inflation through delivery of a real rate of return (derived from a nominal return on debt and equity, less the estimate of expected inflation). In making the negative adjustment to

[76] Refer Section 3 of Attachment 9.1 for the calculation of the residual value.

regulatory depreciation for expected inflation, the AER is therefore seeking to estimate and 'back-out' inflation expectations assumed in the nominal rate of return.

However, if expected inflation is over-estimated and does not reflect market expectations of inflation in the nominal rate of return, then the deduction for inflation made to determine regulatory depreciation will be greater than the compensation for inflation that will be delivered. This means that the real rate of return will be lower than it should be and the business will not be provided with a reasonable opportunity to recover its efficient costs through its prices over the AA period (which means actual revenue will be below allowed revenue).

Importantly, under the AER's current approach, there is no mechanism to revisit the amount of inflation that is removed from revenue through regulatory depreciation. This has been a particular issue across our networks over recent years, where actual inflation has been well below the forecast of inflation used to set revenue/prices. For example, the most recent actual inflation used to adjust our Victorian prices for 2017 was 1.3%, which is well below the forecast of 2.4% currently used to set allowed revenue.

This is one of the key outstanding issues following our recent South Australian AA review process. We are therefore keen to resolve this issue with the AER and our stakeholders in this review process. We note that the AER has recently indicated that it indents to start dedicated engagement on inflation in 2017, which we consider to be a good initiative. We intend to participate in this engagement process.

The remainder of this section sets out our views on the best estimate of expected inflation and, consistent with stakeholder feedback on our Draft Plan, discusses some alternate options that may improve our ability to recover our efficient cost over the next AA period. Further information on our response to the best estimate of expected inflation and potential alternate approaches is provided in Attachment 9.2 to this Final Plan.

9.5.3.1. Best Estimate of Expected Inflation

The overarching objective in determining a best estimate of expected inflation is for the estimate to be consistent with the expectations of inflation that are reflected in the nominal rate of return. If this is the case, and as explained above, the deduction of expected inflation in determining regulatory depreciation is the same as the double count for inflation included when determining the return on capital. This consistency will ensure that allowed revenue reflects efficient costs.

The AER recently explained the need for consistency between the estimate of expected inflation with the nominal rate of return (or Weighted Average Cost of Capital (WACC)):

> *"A nominal WACC, not a real WACC, is the input to the PTRM [Post-tax Revenue Model] at the start of each AER final decision. The real WACC (which drives PTRM outcomes) is derived from the nominal WACC by deducting the expected inflation rate. Hence, an overestimate of inflation means the real WACC will be too low (and vice versa). However, the forecast inflation and the nominal WACC are jointly estimated on consistent terms. Directly using the real WACC in the model means we have **assumed** that this pair of inputs is correctly matched. For example, if forecast inflation is overestimated, but this overestimate of inflation is already included in the nominal rate of return, the real WACC will still be correct."* [77] [Emphasis added]

The AER points to the importance of ensuring that expected inflation and the nominal rate of return *"are jointly estimated on consistent terms"* in order to achieve the objective *"that this pair of inputs is correctly matched"*. If this is the case, then allowed revenue will reflect efficient costs.

[77] AER, *Attachment B - Explanatory Statement | Proposed amendment electricity distribution network service providers Roll Forward Model (version 2)*, August 2016, pages 26-27.

This is because, for example, any overestimate for inflation included in the rate of return will be removed in the deduction for expected inflation in determining regulatory depreciation.

The key therefore is whether the estimate of expected inflation is "jointly estimated on consistent terms" and "correctly matched" with the expected inflation included in the nominal rate of return. The importance of having matched inputs reflects that there is no mechanism under the AER's approach to adjust the estimate of expected inflation used to determine allowed revenue for actual inflation (unlike the adjustment made to the capital base).

The two most recent approaches to estimating expected inflation are the:

- *AER approach* – which approach develops a 10-year estimate of expected inflation based on a combination of the RBA's short-term estimate of expected inflation (for the first two years of the 10-year term) and the mid-point of the RBA's longer-term target range of inflation (for the past eight years); and
- *Market-based approach* – which approach is preferred by AGN and develops an estimate of expected inflation based on the difference between yields on nominal and inflation indexed 10-year Commonwealth Government Securities (CGS), also referred to as the "break-even" or Fisher equation approach.

In its recent decision for our South Australian network the AER derived an inflation forecast of 2.39%. Our preference was to use the market-based approach, which derived 10-year inflation forecasts of around 1.5%. This was compared to actual inflation prevailing at the time of 1.3%[78] (we note the most recent actual inflation is 1.3%[79]). Even though the AER's approach is to estimate inflation expectations over a 10-year horizon, the current inflation environment is relevant and will impact on investors' expectations of inflation over the next AA period.

We prefer the market-based approach because it uses the same market information used to determine the rate of return. That is, in our view, the market-based approach to estimating expected inflation is *"jointly estimated on consistent terms"* and is *"correctly matched"* with expected inflation reflected in the nominal rate of return. To understand this further, the AER estimates the nominal rate of return based on the following key inputs:

- the cost of debt is based on 10-year nominal corporate bond yields; and
- the cost of equity is based on 10-year nominal CGS yields as the proxy for the risk free rate.

We therefore consider that the above market based information used to determine the nominal rate of return is the most consistent and logical information to use to estimate expected inflation. Moreover, this information reflects market determined (investor) views of expected inflation. We therefore consider that the market-based approach best meets the AER requirement for expected inflation to be "*correctly matched*" with the nominal rate of return and gives rise to the best estimate of expected inflation possible in the circumstances.

9.5.3.2. Assessment of Approaches

Figure 9.1 compares the estimates of expected inflation using the AER approach and the market-based approach against actual inflation. This shows that the market-based approach produces an inflation estimate that most closely aligns with actual inflation, which is highly relevant to investor expectations of inflation over the next AA period. This continues to be the case if comparing the implied one year inflation estimate of 2% under the AER approach against actual inflation (noting that both approaches produce 10-year estimates).

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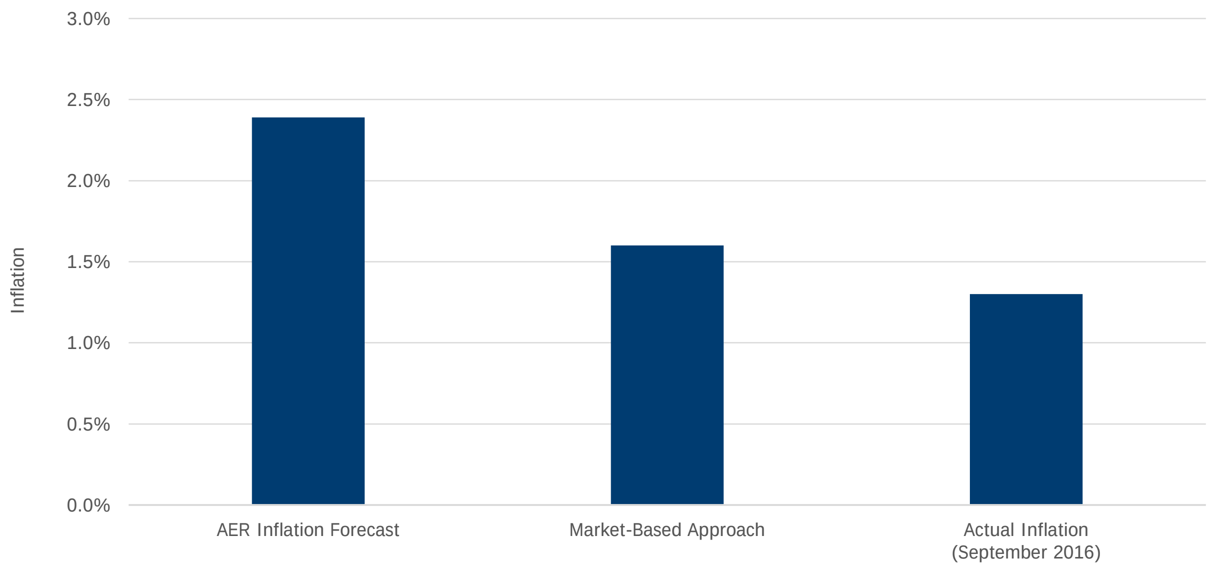
78 ABS, *Consumer Price Index March Quarter 2016*, April 2016.

79 ABS, *Consumer Price Index September Quarter 2016,* October 2016.

Figure 9.1: Estimates of 10-Year Inflation Against Actual Inflation



We have also compared the inflation indexed 10-year CGS yield (light blue line in Figure 9.2) and the nominal 10-year CGS yield (used to derive the cost of equity) less the estimate of expected inflation derived using the AER approach (dark blue line in Figure 9.2). In effect, this compares the real risk free rate available to investors in the market (i.e. the light blue line) and the real risk free rate implied by the AER approach (i.e. the dark blue line).

Figure 9.2 Comparison of Indexed CGS to AER Derived Real CGS

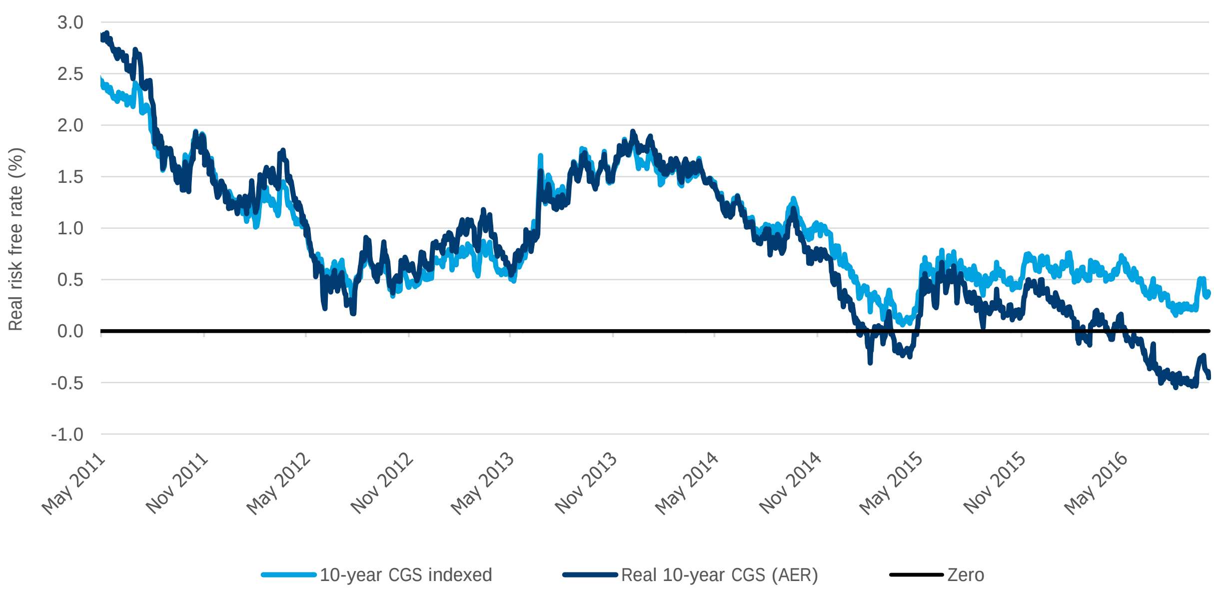


Figure 9.2 shows that, until late 2014, the AER approach implied a real risk free rate that was consistent with the (actual) yield on indexed CGS. This has not, however, been the case since that time, with the implied and actual real risk free rates diverging. This lack of consistency suggests

that the RBA-based approach is not "*correctly matched*" to the market-based information used to set the rate of return.

The implied risk-free rate using the AER approach has been negative for most of 2016 (at -0.5% at 30 September 2016[80]). A negative real rate of return implies that investors are willing to lend to the Australian government in return for receiving less, in real terms, after 10 years than they originally invested. This is clearly not the case as investors, in September 2016, could have actually lent to the Australian government with the guarantee of a positive real return (i.e. the light blue line).[81]

Figure 9.2 clearly demonstrates that the AER approach to estimating expected inflation is inconsistent with market expectations of inflation. As such, we consider that the AER approach is inconsistent with the implied inflation in the nominal rate of return. Under current conditions, applying the AER approach to set our revenue would provide a windfall loss to AGN of around $16 million per year, thereby not providing AGN with a reasonable opportunity to recover its efficient costs.

A related concern we have is that we would not recover the benchmark real rate of return even if actual annual inflation matches the forecast annual inflation underpinning the AER approach. We estimate this variance to be equivalent to a 0.5% decrease in the rate of return over the five-year period, or approximately $8 million over the next AA period. Attachment 9.4 provides a simple model demonstrating this concern.

We therefore consider that the available information demonstrates that the AER approach to estimating inflation does not "*correctly match*" inflation expectations in the nominal rate of return with its estimate of expected inflation.

9.5.3.3. AER Concerns with Market-based Approach

The AER in its Final Decision for our South Australian network raised several concerns over whether the market-based approach can be relied upon to develop reliable estimates.[82] These concerns related to whether there was sufficient liquidity in the market for indexed CGS, the potential bias in the market-based estimate and the potential to use other market-based information, such as inflation swaps, to forecast inflation.

We have considered the matters raised by the AER and do not consider they are sufficient to warrant not using the market-based approach to estimate expected inflation. This reflects our view (as explained in more detail in the attachments) that:

- The current liquidity of the market for indexed CGS is sufficient to be used in the breakeven approach. On this matter, PwC found that:

  > "*… Indexed CGS are sufficiently "liquid" for their pricing to be reliable input for the Breakeven model, for several inter-related reasons* "[83]

PwC also state that:

> "*… the low relative trading volume of Indexed to Nominal CGS does not introduce a liquidity bias. We therefore do not believe a liquidity bias needs to be removed from the pricing of Indexed CGS. Our analysis shows that Indexed CGS have strong*

[80] We have relied upon information available up to 30 September 2016 when determining values in relation to inflation (and rate of return).

[81] In addition, a comparison of the AER approach and the market-based approach over recent years shows that the market based approach has better predicted actual inflation. This is demonstrated in more detail in Attachment 9.2.

[82] AER, *Final Decision, Australian Gas Networks 2016-21, Attachment 3*, 26 May 2016, pages 153-158.

[83] PwC, *Estimating Expected Inflation Using the Breakeven Method,* December 2016. Provided at Attachment 9.3.

reliability and "price efficacy" which describes the degree to which a security reflects the true market price and not distorted for reasons such as lack of turnover"[84]

- There has been significant new issues of indexed CGS since 2012. In rejecting the break-even approach for our South Australian network the AER relied upon literature that only considered the depth of the indexed bond market prior to 2012. The indexed bond market has grown considerably since this time.
- The smaller size (short supply) of the indexed CGS market was previously attributed as a reason for break-even inflation overstating expected inflation (not understating it). If any such "*distortions*" in the CGS market still existed, this would imply actual expected inflation is even lower than current break-even estimates.
- The potential bias referred to by the AER is not relevant to current domestic market conditions and is by its nature symmetric (i.e. can equally lead to over or under estimates of expected inflation using the market-based approach. Moreover, and as noted by the AER, any potential bias is often immaterial).
- Inflation swaps are issued by banks and therefore reflect not only the market expectations of inflation, but also include a risk premium and the capital costs of the banks providing these products. Inflation swaps will therefore require specific deductions to account for these additional bank costs in order to reveal the market expectation of forecast inflation, which deductions would approximate 0.5%.[85] Making this adjustment to the inflation swaps results in an estimate of inflation that is similar to the market-based approach.

We do not therefore consider that the above concerns raised by the AER invalidate the use of the market-based approach, particularly when considered against the more fundamental matter that the market-based approach is, to a greater extent, "correctly matched" with the information used to determine the nominal rate of return relative to the AER approach. To this end, PwC note that:

> *"The pricing of the two instruments* [being the nominal CGS and indexed CGS] *is inextricably linked via the inflation expectation and it is this variable that determines the pricing of the Indexed CGS. This provides certainty that the Breakeven inflation rate is robust to capture the markets future inflation view and expectation"*"[86]

Further information on our response to the AER concerns is provided in Attachment 9.2, with supporting expert evidence in Attachments 9.3 to 9.5.

9.5.3.4. Alternative Approaches

Stakeholders at our workshop on the Draft Plan were keen to ensure that the regulatory model does not provide windfall gains or losses to either AGN or its customers. This led to suggestions on how the regulatory regime could provide for a true-up between actual and forecast inflation. Suggestions put forward at the workshop included not adjusting the capital base for actual inflation and forecasting inflation over a five-year period and not a 10-year period.

Our primary concern is to ensure that the best estimate of expected inflation is used to determine our allowed revenue (and prices). We do, however, consider that there is also merit in exploring alternate approaches for dealing with inflation, including those options suggested by stakeholders. We also note that the AER is currently considering a proposal to update inflation annually at the

[84] PwC, *Estimating Expected Inflation Using the Breakeven Method,* December 2016. Provided at Attachment 9.3.

[85] CEG, *Best estimate of expected inflation,* September 2016, Appendix B. Provided at Attachment 9.4 to this Final Plan.

[86] PwC, *Estimating Expected Inflation using the Breakeven Method,* December 2016, page 3. Provided at Attachment 9.3 to this Final Plan.

same time the 10-year average cost of debt index is updated.[87] Other possible approaches are also noted in Attachments 9.2 and 9.5.

We are therefore keen to continue to explore these options with the AER and stakeholders over this review process, and as noted earlier, participate in the dedicated engagement on inflation recently initiated by the AER to occur in 2017.

9.5.3.5. Summary

We consider the estimate of expected inflation to be one of the key outstanding issues to be resolved with the AER following our South Australian AA review process.

We believe that the market-based approach provides the best estimate of expected inflation over the next AA period. This is primarily because the market-based approach is:

- *"correctly matched"* with expected inflation reflected in the nominal rate of return on the basis that both estimates rely on the same market information; and
- *"jointly estimated on consistent terms"* with the nominal rate of return as demonstrated by a comparison of actual real CGS yields and implied real CGS yields using the AER approach to forecasting inflation.

As at September 2016, the market based approach would give rise to an estimate of expected inflation of around 1.6%.

We have, however, assumed the AER approach of 2.39% in this Final Plan pending the outcome of further engagement with the AER and stakeholders on this important matter. We also note that the approach to estimating expected inflation is currently subject to legal review.[88] We will continue to monitor this issue and update our approach, if required, once there is further clarity on this matter (including through engagement on our Final Plan).

We are keen to work with the AER to ensure that we adopt the best estimate of forecast inflation to set our revenue/prices over the next AA period.

9.5.4. Forecast Regulatory Depreciation

As noted, forecast regulatory depreciation is used to determine the total revenue that we can recover over the next AA period. This is calculated as forecast straight-line depreciation that is used to adjust the capital base less the inflation adjustment that is applied to the capital base. Table 9.6 shows forecast regulatory depreciation that is used to determine assumed total revenue for the next AA period.

Table 9.6: Forecast Regulatory Depreciation, 2018 to 2022 ($nominal, million)

	2018	2019	2020	2021	2022
Straight-line Depreciation	80.1	88.0	93.3	90.0	96.3
Less Inflation	38.6	40.4	42.6	44.7	46.4
Regulatory Depreciation	**41.5**	**47.6**	**50.7**	**45.2**	**49.9**

Note: Totals may not add due to rounding.

[87] APA, *Roma to Brisbane Pipeline | Access Arrangement Submission,* September 2016, pages 202-208.

[88] In the ActewAGL Distribution merits review application ACT No 6 of 2016.

9.5.5. Forecast Capital Base

The forecast capital base over the next AA period, taking into account forecast (straight-line) depreciation, capex and inflation, is set out in Table 9.7. This shows a closing capital base of $1,977 million as at 31 December 2022 in nominal dollar terms.

Table 9.7: Forecast Regulatory Asset Base 2018 to 2022 ($nominal, million)

	2018	2019	2020	2021	2022
Opening Capital Base	1,615.6	1,691.5	1,783.4	1,871.6	1,943.3
Less Forecast Depreciation	80.1	88.0	93.3	90.0	96.3
Plus Forecast Conforming Net Capex	117.3	139.5	138.9	116.9	83.8
Plus Forecast Inflation	38.6	40.4	42.6	44.7	46.4
Closing Value	**1,691.5**	**1,783.4**	**1,871.6**	**1,943.3**	**1,977.2**

Note: Totals may not add due to rounding.

9.6. Summary

We have adjusted our capital base over the current and next AA periods to reflect actual/forecast capex, depreciation and inflation.

We have adjusted depreciation to reflect the completion of our low-pressure mains replacement program over the next AA period. This adjustment is consistent with our obligations and recent decisions made by the AER. We have also applied the AER's preferred approach to the estimate of expected inflation, pending further engagement with the AER and stakeholders on this important matter and the outcome of legal reviews.

The value of our closing capital base is $1,977 million at the end of the next AA period.

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10. Financing Costs

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10. Financing Costs

10.1. Introduction

Our single largest cost relates to the cost of financing our $1.6 billion investment in our Victorian and Albury natural gas distribution networks (the networks). Achieving a reasonable rate of return that meets the objectives of the National Gas Rules (NGR) is essential in order to attract the necessary funding from shareholders (through equity) and debt providers to continue to invest in our networks. We are also required to estimate the cost of tax the business will incur over the next (2018 to 2022) Access Arrangement (AA) period.

The importance of financing and tax costs has meant that these issues have been highly contentious. There is currently, and has historically been, a large number of legal reviews relating to financing and tax costs which, at the time of this Final Plan, remain unresolved. In fact, since the release of our Draft Plan on 5 July a further judicial review[89] has been lodged. Given this, there is considerable uncertainty regarding these costs.

As a result of the current uncertainty, and consistent with the approach we have taken elsewhere in this proposal, we have decided to apply the approach most recently used by the AER in its recent decision for our South Australian network. We will, however, continue to monitor these issues and consider the outcomes from the legal review processes when available and update our proposal if necessary.

This chapter explains further our approach to forecasting financing and tax costs. Further information on these matters is provided in Attachments 10.1 through to 10.7.

10.2. Regulatory Framework

We are required to set an allowed (or benchmark) rate of return as a weighted average of the return on equity and the return on debt, determined on a nominal vanilla basis.[90] The overarching requirement is that the allowed rate of return must be determined such that it achieves the following objective:

> *"…that the rate of return for a service provider is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the service provider in respect of the provision of reference services".* [91]

Our tax costs must also be estimated with reference to a specific methodology that takes into consideration our forecast taxable income, the applicable corporate tax rate and the value of imputation credits (or gamma) to equity holders.[92]

10.3. Stakeholder Engagement

We engaged with stakeholders in respect of our proposed financing and tax costs, particularly on the approach we are taking to setting the cost of debt and gamma (as we agree with stakeholders that there is now more certainty over the cost of equity). Stakeholders recognised the uncertainty

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89 On 28 November 2016, SA Power Networks commenced a judicial review application in respect of the Tribunal's decision of October 2016 in Action NSD 2032/2016.

90 Rule 87(4) of the NGR, as outlined in Attachment 1.1 to this Final Plan.

91 Rule 87(3) of the NGR, as outlined in Attachment 1.1 to this Final Plan.

92 Rule 87A of the NGR, as outlined in Attachment 1.1 to this Final Plan.

arising from the current merit and judicial review activities and supported our approach to adopt the Australian Energy Regulator (AER) preferred approach until such time that the uncertainty is resolved.

Table 10.1: Consideration of Stakeholder Feedback on Tax and Financing Costs

Draft Plan Stakeholder Question	Stakeholder Feedback[93]	Our Response to Feedback on our Draft Plan
Do you have any comments on our approach to setting financing and tax costs in this Draft Plan?	Stakeholders were supportive of our approach to setting the rate of return and gamma, which approach is to adopt the AER's preferred approach pending any further information resolving the current uncertainty. In doing so, stakeholders acknowledged our approach of seeking to resolve issues with the AER and stakeholders.	Our approach to setting the rate of return and gamma is consistent with that outlined in our Draft Plan and our overarching approach of adopting AER positions pending further information resolving current areas of uncertainty. We expect that, if more certainty is provided, this will be reflected (to the extent required) in our subsequent proposals to the AER and/or AER decision. This will ensure the most recent/accurate information is used to set financing and tax costs and that we are treated consistently with other businesses.
	Stakeholders were interested in the different approaches for determining the return on debt and the mechanics of transitioning to a 10-year trailing average cost of debt. While applying the AER approach, stakeholders acknowledged the "hybrid" transition most closely aligns with our actual debt management practices.	We agree that the hybrid approach more closely aligns with our own debt financing practices. However, and as noted above, we intend to continue to apply the AER preferred approach pending further clarification by way of the outstanding legal reviews or information suggesting that this is no longer appropriate.
	Stakeholders did consider that much of the contention relating to the cost of equity had dissipated following the recent decision on this matter by the Australian Competition Tribunal.	We agree and have applied in this Final Plan the AER's preferred approach to determining the cost of equity.
	It was noted that the proposed and actual rate of return would change depending on movements in market based parameters and the choice of averaging period (there was discussion over how the averaging period would be set).	We agree with this feedback and have nominated in our Final Plan future averaging periods consistent with the guidance provided by the AER.

Note: In this 'traffic light' table, green shading represents no change from the Draft Plan, orange shading represents a modification of the position outlined in the Draft Plan and red shading represents change from the Draft Plan.

10.4. Financing Costs

Our financing costs are determined based on an estimate of the return on equity and the return on debt to be incurred over the next AA period, which are together referred to as our rate of return and are discussed in this section.

93 Deloitte, *Stakeholder and Customer Feedback Report*, December 2016. Provided as Attachment 5.10 to this Final Plan.

10.4.1. Return on Equity

The return on equity reflects the return required by shareholders to invest in the network. Unlike the return on debt, it is not possible to observe the return on equity required by shareholders in the market. This means that we are required to use financial models and other market evidence to inform the estimate of the return on equity.

The AER estimates the return on equity using the Sharpe-Lintner Capital Asset Pricing Model (CAPM) as its "*foundation model*"[94], which requires the following three parameters to be estimated:

- *The risk free rate* – which measures the return an investor would expect from an asset with no risk. It is estimated based on the observed yield on Australian Commonwealth Government Securities (CGS) with a 10-year term measured over an averaging period prior to the commencement of the AA period;
- *Market risk premium (MRP)* – which reflects the expected return over the risk free rate that investors require to invest in a well-diversified portfolio of risky assets (also assumed to be a 10-year term); and
- *Equity beta* – which measures the sensitivity of a business's returns relative to movements in the overall market returns (referred to as systematic or market risk).

We note that the estimate of the return on equity arising from the AER's approach, particularly around estimating the MRP and equity beta, is still a contentious issue.[95] We describe the nature of this contention in more detail in Attachments 10.1 to 10.3. We have applied in this Final Plan the AER's foundation model and most recent estimates of the above parameters, which results in a return on equity of 6.58% over the next AA period (see Table 10.2).

Table 10.2: Indicative AER Return on Equity

Parameters	Our Indicative Proposal
Risk Free Rate (Average of observed yields on 10-year Australian government bonds over agreed averaging period)	2.03% (Using a placeholder 20-day averaging period ending on 30 September 2016)
Equity Beta	0.7
Market Risk Premium (MRP)	6.5%
Return on Equity	6.58%

The cost of equity, particularly the risk-free rate component, is based on the most recent market information available prior to finalising this Final Plan.[96] These values are indicative and will be updated in the AER's Final Decision in accordance with the confidential averaging period we have nominated (see Attachment 10.8). Our nominated averaging period is consistent with AER

94 The AER foundation model approach is based solely on the application of the Sharpe-Lintner Capital Asset Pricing Model (SL CAPM).

95 For example, AusNet Transmission recently proposed an MRP of 7.5% relying on a report from Frontier Economics: *The market risk premium*, September 2016. AGN is also aware of work done by CEG to update the equity beta estimates relied upon by the AER (CEG: *Replication and extension of Henry's beta analysis*, September 2016). The CEG update shows that equity beta estimates have increased.

96 We have used actual information through to the end of September throughout this Final Plan.

guidance, including that the averaging period must be nominated in advance and occur prior to the start of the next AA period.

10.4.2. Return on Debt

The return on debt reflects the interest rate required by debt holders on issued debt (or the interest rate on our loans). Much like the return on equity, the return on debt can be thought to comprise a base interest rate and a risk premium, in this case referred to as the debt risk premium (DRP).

Historically, and consistent with parameters used for the return on equity, the return on debt was measured over a short averaging period just prior to the start of an AA period (referred to as the 'on-the-day approach'). There is now general agreement that the interest rate should reflect an average over a 10-year historical period (reflecting the average length or tenor of the benchmark efficient entity's debt portfolio). This is commonly referred to as the trailing average approach.

The main points of difference between the AER and some electricity and gas distributors, which is the subject of the legal reviews referred to earlier, relates to:

- the definition of the "*benchmark efficient entity*" (or BEE) as set out in the overarching requirement guiding the setting of the allowed rate of return (see Section 10.2), particularly whether the BEE is a regulated or an unregulated entity;
- whether the 10-year trailing average return on debt should apply immediately or whether there should be some form of transition to this new approach from the previous on-the-day approach (our current prices are based on the on-the-day approach); and
- if there is to be a transition, the form of that transition.

The key approaches to estimating the return on debt that are currently under consideration, including through legal review, are:

- *The AER Guideline transition* – which implements a 10-year transition to the trailing average approach, the transition applying to both the base rate and the DRP;
- *Immediate implementation* – under which no transition is applied so that the 10-year trailing average applies from the start of the AA period; and
- *A hybrid transition* – which implements a 10-year transition to the base interest rate component (or a proportion of the base rate component that it was efficient to hedge) but not to the DRP component of the return on debt.

The above options reflect different views on whether the BEE is regulated or unregulated, whether there should be a transition to the trailing average approach, and if so, what form the transition should take.

For example, it is generally accepted that an unregulated entity in a workably competitive market would already have a portfolio of staggered debt reflecting a 10-year trailing average. No transition to a trailing average approach would therefore be necessary if the benchmark efficient entity is deemed unregulated (which matter is a key part of legal reviews that are still pending in regard to the electricity distributors operating in New South Wales and the Australian Capital Territory).[97]

On the other hand, if it is relevant to consider how the benchmark efficient entity would have managed risk under the previous on-the-day approach in the regulatory regime, this may give rise

[97] *Application by PIAC, Ausgrid* [2016] ACompT 1 and the judicial review application of that decision.

to support for the hybrid transition on the basis that the benchmark efficient entity may have entered into arrangements that locked-in (or fixed or hedged) the base interest rate over the agreed averaging period. As noted by stakeholders, this is most consistent with our own practices.

As noted above, there is currently considerable legal review of the appropriate approach for determining the return on debt. For example, and relevant to determining the cost of debt, these legal reviews include:

- *In October 2016* – the Full Federal Court heard an application from the AER for judicial review of the Australian Competition Tribunal's (ACT's) decision in the New South Wales decisions handed down in February 2016.[98]
- *On 28 October 2016* – the ACT handed down its decision in respect of a merits review application by SA Power Networks, in which SA Power Networks had proposed a hybrid transition[99]. In that decision, the ACT held that the AER did nor err in preferring its Guideline transition over a hybrid transition. However SA Power Networks on 25 November 2016 sought judicial review of this ACT decision.[100]
- *In November 2016* – the question of the need for, and the form of, a transition was also argued again before the ACT in merits review applications made by certain Victorian electricity distributors and by the Australian Capital Territory gas distributor.[101]

All of the above review processes, some of which were initiated over a year ago, are still to be resolved. Therefore, there remains considerable uncertainty around these issues, with outstanding decisions yet to be delivered on both the immediate implementation and hybrid transition options. The nature of the debate in respect of the various approaches to the return on debt are discussed in more detail in Attachment 10.1.

While the legal reviews have continued the AER has applied its Guideline transition approach to the return on debt, including most recently for our South Australian network. We have assumed a return on debt by reference to the AER Guideline transition until further clarity is provided. This gives rise to a cost of debt of 4.42% over the same placeholder period used to set the return on equity.

We will continue to monitor this issue and will update our proposal, if required, once further certainty is provided arising from the current legal review processes. As noted earlier, this will ensure the most recent/accurate information is used to set financing costs and that we are treated consistently with other businesses.

10.4.3. Rate of Return

The AER assumes that 60% of our total financing costs relate to debt with the remaining 40% relating to equity. Applying these percentages to the return on equity (6.58%) and return on debt (4.42%) results in an overall rate of return of 5.28% over the next AA period. We note that this rate of return will be updated in the AER Final Decision consistent with our nominated averaging period.

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98 In respect of the ACT's decision in *Application by PIAC, Ausgrid* [2016] ACompT 1.

99 *Application by SA Power Networks* [2016] ACompT 11.

100 In NSD 2032/2016.

101 In those proceedings (heard during November 2016), Jemena Electricity Networks (Vic) Ltd (JEN) and ActewAGL Distribution argued for an immediate implementation of the trailing average approach, while JEN also argued (in the alternative) for the implementation of a hybrid transition.

10.5. Cost of Tax

Our tax costs are based on an assessment of our taxable income, the applicable corporate tax rate and the value of imputation credits (or gamma) to equity holders. These matters are discussed in this section.

10.5.1. Calculating the Cost of Tax

We have determined the cost of tax as total revenue (excluding the cost of tax) less opex, tax depreciation and interest expense; where:

- *Total revenue* – is the sum of all of our costs (or building blocks) aside from the cost of tax (see Chapter 12);
- *Operating Expenditure (Opex)* – is a specific building block that is used to determine total revenue (see Chapters 7 and 12);
- *Tax depreciation* – is based on the calculation of the tax asset base in any particular year (see Section 10.5.3); and
- *Interest expense* – is determined by multiplying the cost of debt (of 4.42%) by 60% of our capital base in each year, reflecting the debt funded proportion of the total capital base (see Chapter 9).

The corporate income tax rate is set at 30% consistent with the prevailing corporate tax rate applying in Australia. The value of imputation credits (or gamma), like tax depreciation, is a specific input that is required to determine the cost of tax that is not elsewhere determined. The value of imputation credits is discussed in Section 10.5.2 below.

10.5.2. Value of Imputation Credits

The value of imputation credits is determined by calculating the product of:

- the proportion of imputation credits distributed (the distribution rate); and
- the value of the distributed credits to investors (theta).

There are differences between the AER and networks as to the appropriate conceptual approach to estimating gamma and the approach that should be taken to estimating each of the above parameters. As with financing costs, there has been considerable legal review in relation to the estimate of gamma and ongoing uncertainty as a result. In particular:

- *In February 2016* – the ACT determined that the estimate of gamma that best complies with the relevant regulatory framework is one based on a firm-wide distribution rate of 0.7 and an estimate of theta of 0.35. This gives rise to an estimate of gamma of 0.25 and the ACT directed the AER to re-make its decisions applying a gamma of 0.25.[102] However, the AER has sought judicial review of the ACT's decision, which was heard by the Full Federal Court in October 2016 and with a decision pending.
- *In October 2016* – the ACT published its decision in respect of SA Power Networks merits review application. The ACT in that case found no error in the AER's decision to apply a gamma of 0.4. However, SA Power Networks has sought judicial review of the ACT's decision.

[102] *Application by PIAC, Ausgrid*, [2016] ACompT1.

- *In November 2016* – the ACT heard the Victorian electricity distributors[103] and ActewAGL Distribution appeal of the AER's equivalent gamma determination. The ACT's decision is also pending.

Again, all of the above reviews are still to be resolved, which means there is also still considerable uncertainty on the appropriate value of gamma. Our view is that the best estimate of gamma currently available is 0.25, based on a market-wide distribution rate of 0.7 and an estimate of theta of 0.35. Our reasons for this view are set out in detail in Attachment 10.7.

Given the current uncertainty arising from the legal reviews, we intend to continue to discuss the approach to gamma with the AER through the review process. For the purposes of this proposal we have assumed a value for gamma of 0.4 based on the most recent decision made by the AER for our South Australian network. As with financing costs, we will continue to monitor this issue and update our proposed value for gamma, if required, once the legal review outcomes are known.

10.5.3. Tax Depreciation

Tax depreciation is used to determine the estimate of taxable income and to update the value of our Tax Asset Base (TAB), as shown in Section 10.5.4. We have applied tax asset lives that are consistent with guidance provided by the Australian Tax Office (ATO).[104] We have also consolidated the TAB into a form consistent with the financial models used by the AER, as applied in the most recent decisions for the Victorian electricity distributors.

10.5.4. Tax Asset Base

The opening TAB of $722 million ($nominal) as at 1 January 2018 has been adjusted for the same forecast information used to adjust our capital base over the next AA period (see Table 10.3).

Table 10.3: Roll Forward of the Tax Asset Base 2018 to 2022 ($nominal, million)

	2018	2019	2020	2021	2022
Opening Tax Asset Base	721.9	811.2	914.1	1,008.3	1,072.7
Plus Gross Capex	117.1	139.0	138.4	116.8	84.2
Less Tax Depreciation	27.7	36.2	44.2	52.4	55.4
Closing Value	**811.3**	**914.1**	**1,008.3**	**1,072.7**	**1,101.4**

Note: Totals may not add due to rounding.

10.6. Summary

Our financing and tax costs account for around 50% of our total costs. There is considerable uncertainty around the correct approach to setting the rate of return and gamma as a result of ongoing legal processes. Given this uncertainty, and consistent with our general approach in this Final Plan, we have determined a rate of return and gamma by reference to the approach most recently applied by the AER for our South Australian network (see Table 10.4).

[103] United Energy Distribution, Jemena Electricity Networks, CitiPower and Powercor Australia and AusNet Electricity Services.

[104] Australian Tax Office, *TR 2015/2 - Income tax: effective life of depreciating assets (applicable from 1 July 2015)*, Table: Gas Supply (27000), pages 161-162.

We will however continue to monitor the outcomes of the current legal reviews and make any required adjustments to our proposed financing and tax costs once more certainty is provided. This will ensure that the most recent/accurate information is used to set financing and tax costs and that we are treated the same as other businesses.

Table 10.4: Indicative AER Rate of Return and Gamma

Parameters	AGN Final Plan
Return on Equity	6.58%
Return on Debt	4.42%
Overall Rate of Return	**5.28%**
Gamma	0.4

11. Incentive Arrangements

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11. Incentive Arrangements

11.1. Introduction

Australian Gas Networks Limited (AGN) is a strong supporter of effective, outcome-based incentive arrangements as a way of promoting the long-term interests of our customers. Consistent with this, we are proposing to strengthen the incentive arrangements to apply in Victoria and Albury over the next (2018 to 2022) Access Arrangement (AA) period. Our proposal seeks to more closely align the incentives that apply to gas distributors with those applying to electricity distributors.

This chapter explains the incentive arrangements we consider should apply over the next AA period, including how stakeholder feedback arising from our dedicated engagement program has informed our proposal.

We note the Australian Energy Regulator (AER), just prior to AGN finalising this Final Plan, released an Information Paper on incentive arrangements for gas distributors. We have not considered this paper in any detail yet, but intend to do so by engaging further with the AER on the Information Paper. We consider this to be a good initiative by the AER and encourage other stakeholders to participate in this engagement process.

11.2. Regulatory Framework

A key requirement of the National Gas Objective (NGO) is for the regulatory framework to promote efficient investment in and operation and use of our gas distribution networks. In support of this requirement, the National Gas Rules (NGR) provides that an AA may include (or the AER may require it to include) one or more incentive mechanisms to encourage efficiency in the provision of services, which includes promoting:

- efficient investment in, or in connection with, our networks;
- efficient provision of Reference Services to our customers; and
- efficient use of our network by our customers.

11.3. Stakeholder Engagement

We commenced engaging with stakeholders on the appropriate incentive arrangements that should apply to gas distributors as part of our recent South Australian AA review process. This section describes that process and explains the further dedicated engagement that we have undertaken to inform this Final Plan.

11.3.1. Our South Australian Proposal

We recently proposed to strengthen the incentive arrangements that apply to our South Australian network by:

- retaining the existing incentive to lower operating expenditure (opex), which is referred to as the efficiency benefit sharing scheme (EBSS), albeit modified to strengthen the financial incentive to improve opex efficiency;

- introducing an incentive to lower capital expenditure (capex), which is referred to as the capital expenditure sharing scheme (CESS), also modified to strengthen the financial incentives to improve capex efficiency;
- introducing a scheme to promote improved customer service, although AGN had not developed how this scheme would work at the time of providing its plan to the AER; and
- introducing an innovation scheme to promote lower cost and/or improved service delivery and/or environmental outcomes.

Our proposed EBSS and CESS were based on the same schemes that the AER has developed and applied to electricity distributors. The customer service and innovation schemes were new schemes that were based on similar schemes applied by the Office of Gas and Electricity Markets (Ofgem) in the United Kingdom.

The AER accepted the continued application of the EBSS in South Australia but did not accept any of the other proposed initiatives listed above (AGN notes that it only proposed the application of the CESS in response to the AER Draft Decision). The AER in its Final Decision recognised the potential benefits of a CESS, but decided against its introduction on the basis that:

- any changes to the incentive arrangements applying to gas require further consideration and consultation with industry and stakeholders; and
- there is no counterbalancing financial incentive for AGN to maintain or improve network reliability and service.

The Consumer Challenge Panel (CCP) held similar concerns to the AER. In their response to the AER Draft Decision, the CCP noted that:

> *"Having considered the AER's [draft] decision, and the counter arguments put by AGN in the [revised access arrangement proposal], [the CCP] are persuaded that the lack of standard service reliability measures and the need for additional stakeholder consultation mean that it would be premature to introduce a CESS for the next AA period."*[105]

Given this, and as discussed in the next section, we have undertaken further dedicated engagement on our proposed incentive arrangements to apply to Victoria and Albury over the next AA period.

11.3.2. Dedicated Stakeholder Engagement

We understand the preference of the AER and the CCP to consult with industry on the appropriate incentive arrangements for gas distributors. We have therefore undertaken additional engagement through a dedicated stakeholder engagement process with the other two Victorian distributors (Multinet Gas and AusNet Services) and through our Draft Plan.

With regard to our dedicated engagement process, the three Victorian gas distributors engaged an expert, Farrier Swier Consulting (FSC), to facilitate our stakeholder engagement program, which included:

- *the release of an Issues Paper (Attachment 11.1)* – which paper explored issues relating to the potential strengthening of the incentive framework for gas distributors;

[105] Consumer Challenge Panel, *Supplementary advice to AER from Consumer Challenge Panel sub-panel 8 – AGN,*-31 March 2016 page 5.

- *a deliberative stakeholder workshop on the Issues Paper (Attachment 11.2)* – which workshop discussed with stakeholders the key issues/questions raised in the Issues Paper; and
- *the release of a Findings Report (Attachment 11.3)* – which report summarised the engagement process, submissions received to the Issues Paper (Attachment 11.4) and feedback on the deliberative stakeholder workshop (Attachment 11.5).

The key feedback from stakeholders, as reported by Farrier Swier Consulting in their Findings Report, included that:

- there was a general consensus that the incentive framework should be strengthened through the introduction of a CESS;
- there was support for a scheme to provide a counter-balance to the stronger cost reduction incentives created by introducing a CESS; and
- there was support for the idea that network innovation promotes the long-term interests of consumers.

We have also relied on our own stakeholder engagement program to inform the design of our proposed incentive arrangements (see Chapter 5). The relevant insights, as reported in the Deloitte Customer Insights Report (see Section 5.6.2), include that customers:

- traditionally considered gas a cost-effective alternative to electricity, but are concerned with recent price increases – which supports strengthening the incentives to drive efficiency improvements; and
- are supportive of initiatives that maintain reliability and maintain and improve safety of the network – which implies that any scheme that provides a counter-balance to the CESS could promote improvements in safety but not in reliability.

Table 11.1 summarises key stakeholder feedback on our incentives proposal against the questions asked in our Draft Plan and how this feedback has been incorporated in to our Final Plan.

Table 11.1: Consideration of Stakeholder Feedback on our Incentive Arrangements

Draft Plan Stakeholder Question	Stakeholder Feedback[106]	AGN Response to Feedback on Draft Plan
Do you support the objective of strengthening the incentives that apply to gas distributors? If so, should the incentive arrangements be consistent with that provided to electricity distributors?	There was general stakeholder support for strengthening the incentive arrangements, particularly in relation to the introduction of a CESS. There was also support for the introduction of a scheme that provided a counter-balance to the stronger incentive to reduce costs following the introduction of a CESS, although there was not a general consensus on how this scheme should be structured (including whether it should replicate incentives provided to electricity distributors).	We are proposing to re-introduce a CESS with penalties and rewards. In the event of a reward, the payment will be contingent on AGN maintaining service level performance against three network performance indicators. We are also proposing to introduce an innovation scheme, to promote ongoing service improvements including decarbonisation.
What factors should be considered in informing a decision over the appropriate incentives to apply to gas distributors?	Support for our approach to further engage on incentives, including through our dedicated engagement on incentives on the Draft Plan.	Our proposal has reflected feedback from stakeholders.
Do you agree that the EBSS should be retained?	We did not receive specific feedback on this matter, but note the general consensus above that incentive arrangements should be strengthened (indeed, there was no support for weakening the incentive arrangements).	We have proposed the continued application of the EBSS.
Do you agree that a CESS should be re-introduced, including to provide a counterbalance to the EBSS?	As noted, there was broad stakeholder support for introducing a CESS, with the exception of Red Energy/Lumo Energy who stated the existing framework has delivered efficient investment in capex	We have proposed that a CESS be reintroduced to our Victorian and Albury networks.
Should the introduction of a CESS be accompanied by a counterbalancing Service Target Performance Incentive Scheme (STPIS)? What types of measures should be included in a STPIS?	There was no consensus on the appropriate counter-balance for a CESS, with options including a STPIS or strengthening the existing GSL scheme. There was also support for an asymmetric scheme based on our feedback that customers were not willing to pay for improved reliability.	We have proposed a CESS where rewards are contingent on maintaining performance against three network indicators. Any CESS payment is reduced based on our performance against these indicators.
Do you support the introduction of a network innovation scheme aimed at better facilitating innovation or are the current arrangement sufficient? What level of allowance should be allowed under any proposed innovation scheme?	There was general support for providing an incentive for network innovation, although it was questioned whether this would already be provided through the EBSS and CESS.	We have proposed a network innovation scheme to apply over the next AA period.
Do you think there is sufficient evidence to support increasing the incentive power of the EBSS and CESS?	We do not consider that there was strong support for increasing the power of the incentive schemes.	We have not sought to strengthen the power of the current incentive schemes.

Note: In this ‘traffic light’ table, green shading represents no change from the Draft Plan, orange shading represents a modification of the position outlined in the Draft Plan and red shading represents change from the Draft Plan.

[106] Deloitte, *Stakeholder and Customer Feedback Report*, December 2016. Provided as Attachment 5.10 to this Final Plan.

11.4. Current Incentive Arrangements

The incentives that apply to electricity distributors are significantly stronger than those currently applying to gas distributors.

11.4.1. Gas Distribution Incentive Arrangements

The AER currently only applies its EBSS to gas distributors in Victoria. The CESS currently does not apply, despite a similar capex incentive scheme applying previously in Victoria and Albury. There is also a Guaranteed Service Level (GSL) scheme, which provides direct compensation to those customers receiving service levels below pre-defined thresholds. Those aspects of service included in the GSL scheme include:

- customers who experience five or more unplanned interruptions within a calendar year;
- customers who experience an interruption lasting greater than 12 hours;
- the number of appointments not attended to by AGN within two hours of the scheduled time; and
- the number of connections not made within one day of the agreed time.

We support the continued application of the GSL scheme, but note its purpose is to directly compensate customers rather than driving improvements in service for all customers across the network. The financial impact of the GSL scheme is also low, at around $0.1 million per year, and as such, does not provide a sufficient counter-balance to the CESS (nor would it be appropriate to sufficiently increase payments made to customers for service below defined thresholds).

We also have an incentive to reduce unaccounted for gas (UAFG) on the network. The Essential Services Commission (ESC) sets a benchmark UAFG for each AA period, which benchmark is expressed as a percentage of total gas sales/volume. The current AA period benchmark is 3.0% of total volume. We are incentivised to beat the target as we incur a penalty if UAFG is in excess of the benchmark and receive a reward if we fall under the benchmark.[107]

11.4.2. Electricity Distribution Incentive Arrangements

The AER currently applies both the EBSS and CESS to electricity distributors. The AER also applies a:

- *Service Target Performance Incentive Scheme (STPIS)* – which provides for revenue to increase or decrease by up to 5% of average annual revenue depending on performance in respect of certain reliability and customer service measures; and
- *Demand Management Incentive Scheme (DMIS)* – which provides an incentive on electricity distributors to manage peak demand on the network and is generally funded through opex.

Jurisdictional GSL schemes also apply to electricity distributors. The GSL scheme applied to Victorian electricity distributors is consistent with that currently applying to AGN.

[107] The financial reward or penalty is based on the difference between actual and allowed UAFG multiplied by the assumed price (in dollars per GJ) of gas.

11.5. Proposed Incentive Arrangements

Our view is that the incentive arrangements should be designed to:

- balance the incentives to choose the most efficient mix of opex and capex;
- ensure the incentives are the same for each year of the next AA period;
- balance the incentives to reduce opex and capex against the incentive to maintain service quality; and
- ensure there are sufficient incentives to invest in innovation (to find better ways to provide services).

This section discusses our proposed incentive arrangements to apply over the next AA period having regard to the above objectives.

11.5.1. Efficiency Benefit Sharing Scheme

We consider that the EBSS is a well-designed scheme that provides continuous incentives to reduce opex where this is in the long-term interests of our customers. The AER has applied the EBSS across all of our regulated networks, including in Victoria, Albury and most recently in South Australia. We also note that the EBSS is a key part of our opex forecasting approach, which relies on actual incurred opex in the penultimate year of an AA period being efficient (see Section 7.6).

We therefore propose that the EBSS continue to apply over the next AA period and consider this to be non-controversial. We note that we received limited stakeholder feedback on this aspect of our proposed incentive arrangements.

11.5.2. Capital Expenditure Sharing Scheme

We believe that there is a general consensus over the potential benefits of a CESS. For example, as part of the process to change the National Electricity Rules, the Australian Energy Market Commission noted that:

> *"The Commission identified the following benefits with capex sharing schemes in the draft rule determination:*
>
> - *they encourage appropriate network investment;*
> - *they encourage NSPs [Network Service Providers] to look for efficiencies, such as by innovation;*
> - *they provide an incentive for NSPs to reveal their efficient costs; and*
> - *they can be designed to provide for a continuous incentive, that is, the incentives could be set so that the incentive power is the same no matter in which year of a regulatory control period an investment is made."* [108]

Likewise, the CCP in their advice to the AER in respect of our proposal for South Australia noted:

> *"We consider the EBSS and the CESS work together to ensure that there is no bias towards one form of expenditure over another."*[109]

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[108] AEMC 2012, *Economic Regulation of Network Service Providers, and Price and Revenue Regulation of Gas Services, Final Position Paper*, November 2012, page 121.

[109] Consumer Challenge Panel subpanel 8, *Advice to AER from CCP8 regarding AGN's (SA) Access Arrangement 2016-21*, August 2015, page 15.

We consider that there was also stakeholder support for the introduction of a CESS in Victoria, including from Jemena Gas Networks, Energy Networks Australia[110] and more broadly from key stakeholder groups. The Farrier Swier Consulting Findings Report noted that:

> *"There was a general consensus that the incentive framework should be strengthened through the introduction of a Capital Efficiency Sharing Scheme (CESS). The AER published its Statement of Intent 2016-17 during the consultation process which set out its intention to introduce a CESS for gas DBs [distribution businesses]."*[111]

We agree with the above, and as such, propose that a CESS apply over the next AA period. This is primarily because a CESS is required to balance the incentives already provided to opex through the EBSS with the incentives to incur efficient capex. The CESS provides a continuous and symmetrical incentive to ensure the lowest sustainable mix of capex and opex is incurred by the distributor in each year of the next AA period.

The remainder of this section describes our proposed CESS, including how this has been influenced by stakeholder feedback.

11.5.2.1. Proposed CESS

We propose that the same CESS currently applying to electricity distributors should also apply to gas distributors. This is because, consistent with our views on the EBSS, the CESS is a well-designed incentive scheme. The AER CESS has the following key attributes:

- it provides for the same reward and penalty, which is determined as the financing costs on the total difference between actual and allowed capex over an AA period;
  - the calculated CESS amount is then added as a building block in setting total revenue for the subsequent (2023 to 2027) AA period (in the same way the EBSS is now a building block in determining our total revenue for the current and next AA periods);
- like the EBSS, the CESS is designed such that the business retains 30% of the reward/penalty. This removes any incentive to favour capex over opex (and vice versa) as well as to favour underspending at the start of the AA period;
- there are no exclusions (aside from capex allowed under an approved pass-through application);
- it may be adjusted if the AER deems a material amount of capex has been inefficiently deferred into the next AA period; and
- it is already in place for many regulated networks and is understood by stakeholders.

11.5.2.2. Counter-balance to the CESS

The AER in its Final Decision for our South Australian network emphasised the importance of considering the interrelationships between incentive arrangements:

> *"Incentive mechanisms do not operate in isolation. They must work in conjunction with the existing incentives provided to the service provider, both under the access arrangement and more generally. Where an incentive mechanism does not do this, it may in fact incentivise inefficient or imprudent behaviour by a service provider, to the*

[110] Energy Networks Australia, formerly the Energy Networks Association, is the industry body representing all regulated electricity and gas, transmission and distribution businesses.

[111] Farrier Swier Consulting; *Issues Paper Incentive Mechanisms for the Victorian Gas Distribution Business 2018 to 2022 Gas Access Arrangement* Review, 10 June 2016, page 4. Provided at Attachment 11.1 to this Final Plan.

> *detriment of the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.*
>
> *… to contribute to the NGO and be consistent with the RPPs [Revenue and Pricing Principles], an incentive scheme must maintain balance between competing incentives under the access arrangement. For example, a CESS could strengthen incentives to outperform approved capex forecasts, and balance a service provider's incentives to do so across the access arrangement period. As a complement to the opex efficiency carryover mechanisms that have applied in gas for some time, it can also balance incentives to choose capex solutions over opex to maximise carryover amounts under the ECM.*
>
> *However, without a complementary incentive to maintain the quality, safety, reliability and security of supply of natural gas, a CESS may create financial incentives for service providers to reduce capex in a way that could put the safe and reliable operation of the network at risk."* [112]

A key reason for the AER not accepting the CESS in South Australia was the lack of a counterbalancing incentive on network service:

> *"We recognise the potential benefits of a CESS. However, as discussed above we remain concerned that the addition of a CESS to AGN's access arrangement has the potential to create an overall imbalance in incentives under its access arrangement. This could undermine incentives for efficient investment in AGN's network, and potentially incentivise underinvestment. Such an outcome would not promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas. We consider these issues require further consideration and consultation to ensure the suitability of the scheme for gas."*[113]

In our Draft Plan, in response to the above concerns we noted that:

> *"We agree with these views [of the AER and CCP] and propose that a gas equivalent to the electricity STPIS should accompany the introduction of a CESS. This requires a consideration of appropriate measures of reliability and customer service to include in a gas STPIS."*

In our dedicated engagement on incentive arrangements it became clear that a gas STPIS may not be the most suitable scheme to provide a counter-balance to the CESS. To this end, Jemena Gas Networks stated that the:

> *"… assessment of incentives schemes should be informed by the value that customers place on the service attributes being incentivised and these are likely to vary as between distribution businesses."*[114]

Related to this, the Consumer Utilities Advocacy Centre (CUAC) referred to findings from our stakeholder engagement program that customers were satisfied with their current levels of reliability. CUAC therefore suggested that an asymmetric scheme may be more appropriate to provide a counter-balance to the CESS. Farrier Swier Consulting noted in its Findings Report that:

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112 AER, *Australian Gas Networks South Australian Access Arrangement 2016 to 2021*, Final Decision, May 2016, pages 14-8 to 14-9.

113 Ibid, page 14-14.

114 Farrier Swier Consulting; *Issues Paper Incentive Mechanisms for the Victorian Gas Distribution Business 2018 to 2022 Gas Access Arrangement* Review, 10 June 2016, page 13. Provided at Attachment 11.1 to this Final Plan.

> *"There was support for appropriate customer service incentives to counter-balance stronger cost reduction incentives created by introducing a CESS. There were differing views on how this should be achieved. Options included basing a scheme on the scheme applied to electricity distributor businesses and/or through reviewing and strengthening the existing Guaranteed Service Level (GSL) scheme."*[115]

AGN, along with AusNet Services, engaged Farrier Swier Consulting to consider this issue further. Specifically, Farrier Swier Consulting considered the following two options for providing an appropriate counter-balance to the CESS:

- *Gas STPIS* – which scheme would provide rewards or penalties based on our ability to meet reliability, safety and service targets. It would work as a counter balance to the CESS as any inefficient deferral of capital expenditure to maximise a CESS outcome would result in lower than benchmark reliability, safety and/or service performance and therefore a resultant financial penalty would apply.
- *Contingent CESS* – a CESS reward is only accessible to AGN if it meets the specified key network performance indicators. The scheme is asymmetric (i.e. the CESS reward is not increased if AGN were to exceed the performance indicators) and can be proportionate (i.e. the CESS reward received can be discounted if it is achieved at the expense of network performance). A CESS penalty is not discounted if network performance exceeds the targets.

FSC considered which of the above schemes most closely aligned with feedback from stakeholders (see Attachment 11.6 for their report). FSC concluded the contingent CESS is the most appropriate as:

> *"Overall this approach is preferred because it is more proportionate to the incentive issues it seeks to address, particularly having regard to customer preferences for maintaining rather than improving service performance."*[116]

We agree with this view, and as such, propose that an asymmetric scheme accompany the introduction of the CESS. Specifically, we consider that the payment of a CESS reward should be contingent on AGN meeting specified key network performance indicators. We will be required to incur any penalty under the CESS regardless, even if we can demonstrate that an overspend on capex led to an improvement in the key network indicators (on the basis that customers are not willing to pay for this improvement).

Our proposed contingent CESS is consistent with that proposed by AusNet Services and is explained in the next section.

11.5.2.3. Proposed Contingent CESS

Consistent with FSC's findings, we propose to address stakeholder concern about the potential for a CESS to result in lower network performance by making payment of CESS rewards contingent on AGN meeting specified network performance targets. These targets are consistent with the mains condition integrity indicators in our Victorian Distribution Mains and Services Integrity Plan (DMSIP). They will link our eligibility to receive rewards for underspending our capex with our performance relative to historical levels on the following measures:

- *Leaks* – leaks indicate a failure of asset integrity either because of a crack, a break, or leaking joints. Leaks are detected by regular leak surveys or through public reporting and are measured across mains, services, and meters.

[115] Farrier Swier Consulting; *Issues Paper Incentive Mechanisms for the Victorian Gas Distribution Business 2018 to 2022 Gas Access Arrangement* Review, 10 June 2016, page 4. Provided at Attachment 11.1 to this Final Plan.

[116] Farrier Swier Consulting, *Gas Services Incentives in Victoria and Albury*, page 6. Provided at Attachment 11.3 to this Final Plan.

- *Water in the mains* – when water in a main occurs, it is an indicator of a leak in a main.
- *Unplanned SAIDI* – the unplanned system average interruption duration index (SAIDI) measures the outage time experienced on average per customer across our system.

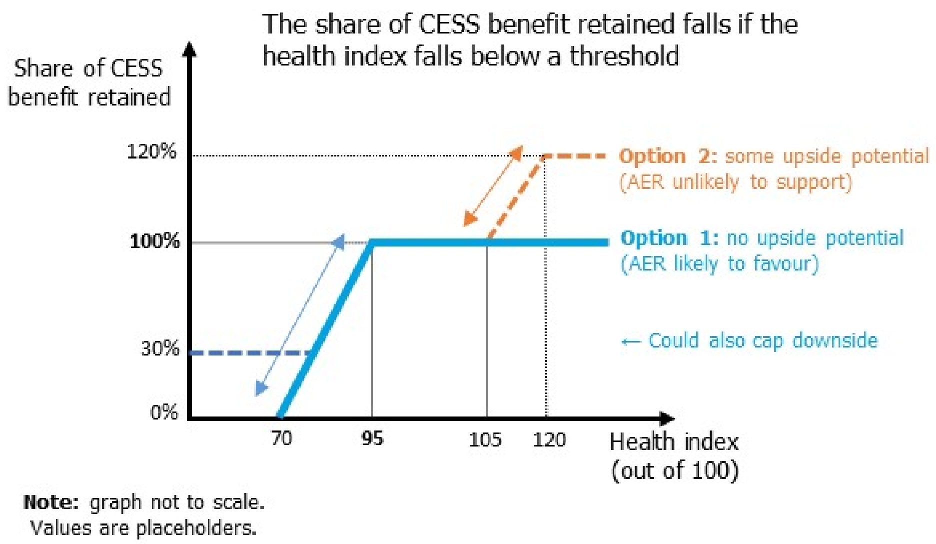
Our proposed contingent CESS reflects stakeholder feedback that customers are satisfied with our current level of performance, and as such, are not willing to pay more to improve service and reliability. In this respect, the contingent CESS does not inflate a reward if we exceed our performance target, but only discounts the reward if we do not achieve the performance target. Further, any penalty earned under the CESS is not discounted if we exceed network performance.

The contingent CESS would determine the reward or benefit based on our performance relative to the allowance. As with the EBSS and the CESS for electricity, the contingent CESS will result in AGN retaining 30% of any capital expenditure outperformance or underperformance relative to the allowance. If the CESS determines a penalty, i.e. a negative adjustment to revenue, then this amount is deducted in full.

However, if a reward is determined under the CESS, then the performance of our network relative to the key indicators is assessed. We will gain access to the full reward if we achieve our historic, or higher, network performance. However, if we fall below our historic performance, our reward will be proportionally discounted on a sliding scale. If we fall below a threshold of network performance, the CESS reward will be removed in its entirety.

The sliding scale is described by the below. In this example, if a business achieves 80% or greater of the network performance target (as shown on the horizontal scale), that business will receive 100% of the CESS reward (as shown on the vertical scale). Network performance less than 80% of the target results in a proportionate discount of the CESS reward down to 0% if network performance falls below 60% of the target. Note that where a CESS penalty is determined, it is passed through in full with no discount.

Figure 11.1: Contingent Payment Sliding Scale



Based on Farrier Swier Consulting, Gas Service Incentives in Victoria and Albury. Provided at Attachment 11.6.

Further information on the potential design of the scheme is discussed Appendix B to Attachment 11.6. As noted earlier, we intend to engage further with the AER and our stakeholders on our proposed contingent CESS leading into the AER's Draft Decision.

11.5.2.4. Further Development of Incentive Arrangements

We do not presently propose to introduce a gas STPIS as contemplated in our Draft Plan due to insufficient stakeholder support at this point. We consider this matter should be subject to further analysis over the next AA period for its suitability to include in subsequent AA periods. We also consider that the type of performance measures that should be incentivised could also be put to further engagement, including in relation to customer service.

To this end, since December 2015 we have been measuring customer satisfaction across the following four areas:

- *Unplanned Interruptions* – this includes satisfaction in respect of the duration of the interruption, clarity of communication and the overall quality of the work carried out;
- *Planned Interruptions* – similar to *Unplanned Interruptions*, but also enquires as to the advance notification given of the gas supply interruption;
- *New Connections* – this includes satisfaction in respect of the quality and the length of time taken to complete the connection to our network; and
- *Complaints* – this includes satisfaction in respect of the ease and speed with which the query was resolved, clarity of communication and the professionalism of our staff.

We consider the above customer service satisfaction measures, as well as network reliability and safety measures, could be developed further over the next AA period for use in a potential gas STPIS if there is sufficient evidence that there is stakeholder support for such a scheme.

11.5.3. Network Innovation Scheme

The incentive for a regulated business to invest in innovation is different to an unregulated business. This relates to the periodic resetting of costs (and prices) for a regulated business at five yearly intervals. This might result in an inability for the regulated business to retain the benefit of that innovation for a sufficient period of time to offset the cost of that innovation. This is particularly the case where:

- an allowance for innovation is not included in the allowed opex and capex benchmarks;
- revenue/prices are reset shortly after the innovation (such that the benefits of that innovation are also passed through to customers after a short period); and
- an EBSS and/or CESS apply (such that the distributor will incur a penalty resulting from the investment in innovation for a period of five years).

The above suggests that the scope/incentive for a regulated business to invest in innovation can be limited. This limits the potential benefits of innovation to the distributor to an (unlikely) maximum of five years. There is the (likely) potential, however, that the costs and risks associated with spending on innovation may require a longer payback period, particularly in light of the potential size of the investments required for gas pipelines.

The consequence of the above is that otherwise beneficial innovations are not pursued, or only those innovations that are low cost and have a shorter payback period are investigated and implemented. This outcome is not in the long-term interests of consumers, and as such, does not lead to outcomes that promote the NGO. We therefore consider that a scheme that facilitates investment in innovation should apply to gas distributors.

11.5.3.1. Proposed Network Innovation Scheme

We are proposing a scheme that is similar in its intent to the DMIS discussed earlier, which scheme allows electricity distributors to seek additional funding (generally through opex) to manage peak demand on the network instead of investing in network augmentation. The electricity distributors apply to the AER for amounts up to $1 million per year to invest in demand management (but only recover the amount they spend).

Consistent with stakeholder feedback, our starting point for designing the network innovation scheme (NIS) is the DMIS that the AER applies to electricity networks. Like the DMIS, under our proposed NIS:

- the AER would approve projects that qualify for NIS funding before we commence them, having regard to agreed project criteria;
- AGN will be able to apply to the AER for amounts up to $1 million per year to invest in innovation;
- any approved expenditure on innovation is excluded from the operation of the EBSS and CESS; and
- AGN will only recover, through tariffs, amounts we have actually spent on approved projects.

11.5.3.2. Criteria for the Network Innovation Scheme

In order to receive the funding, it is proposed that AGN is required to demonstrate that the use of the innovation funding meets the following criteria (which criteria are similar to that used by Ofgem to administer their equivalent innovation scheme):[117]

- the project must have the potential to have a direct impact on our operations and involve the research, development or demonstration of at least one of the following:
  - a piece of new equipment, such as control and communications systems and software;
  - a novel arrangement or application of existing network infrastructure;
  - a novel operational practice directly related to the operation or safety of the network or improvement in customer service;
  - a novel commercial arrangement; or
  - a reduction to the carbon intensity of the gas distributed by the network;
- the project must have the potential to develop learning that can be applied by other gas distributors in Australia;
- the project must have the potential to deliver net financial benefits and/or improvements in our service to gas customers; and
- any intellectual property developed must be made available to third parties.

The above is not intended to be an assessment of the broader merits, or efficiency of the expenditure. This is because, after-the-fact, it is possible that expenditure on unsuccessful innovations might not otherwise be considered prudent. The criteria is instead intended to govern the ex-ante review by the AER of any proposed innovation expenditure.

Our key focus on innovation will be a consideration of where and how gas will fit into the overall energy mix into the future, including how we can decarbonise natural gas supply. We therefore consider that a greater focus on innovation is key to the long-term future of natural gas supply,

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[117] Ofgem, *Gas Network Innovation Allowance Governance Document*, version 2, 2 April 2015.

including the ongoing efficient utilisation of our network and the ability to recover our efficient costs.

Innovation schemes are commonplace across most industries, including electricity distribution in Australia (through the DMIS) and electricity and gas distribution in the United Kingdom. Benefits of these schemes can include lower energy bills, improved environmental outcomes (our key focus), improved reliability and safety, better quality of service and societal benefits to low income earners. For example:

- the H21 Leeds City Gate project is studying the feasibility of converting a natural gas network to 100% hydrogen, which will completely decarbonise gas supply;[118]
- Geneco, a business owned by Wessex Water, now upgrades biogas produced from anaerobic digestion in the Bristol sewage treatment works and injects it into the gas distribution network;[119]
- the New York Power Authority's 'Digital Avatar' project will yield USD2 billion in savings to customers through predictive analytics and integrated operations, thereby lowering the cost of the network and customer bills;[120] and
- Ofgem has committed £44.6 million in funding toward smart grid pilot projects to boost the reliability of the United Kingdom's gas and electricity networks. [121]

These projects have been facilitated by a form of innovation allowance (or scheme) provided by the regulator that allows for collaboration between technology inventors, industry and consumers. These projects have changed industry culture and provided benefits to all participants, thereby promoting the long-term interests of consumers. This demonstrates the importance of innovation schemes in facilitating timely responses to changing market conditions and customer values.

11.6. Summary

We consider the incentive arrangements that apply to gas distributors over the next AA period should be strengthened. Also, our proposal seeks to more closely align the incentives that apply to gas distributors with those applying to electricity distributors having consideration for feedback received from our stakeholders. In this Final Plan, we are proposing to:

- *retain the existing EBSS* – which provides continuous incentives to lower opex;
- *re-introduce a CESS* – which provides continuous incentives to lower capex and provides a counterbalancing incentive to the EBSS;
- *make any CESS payments contingent on maintaining network performance* – which address key stakeholder concerns that reductions in capex are not to the detriment of network performance; and
- *introduce a network innovation scheme* – which will facilitate improved investment in network innovation and contribute to ensuring the ongoing viability of natural gas supply.

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[118] For more information see: http://www.northerngasnetworks.co.uk/document/h21-leeds-city-gate/.

[119] This is a natural process in which micro-organisms breakdown biodegradable waste and convert it to gas. For more information see: http://www.geneco.uk.com/Our_services/Biomethane/.

[120] Predictive analytics used techniques from data mining, statistics, modeling, machine learning and artificial intelligence to analyse data and make predictions about possible future events providing in this case failure scenarios and preventative maintenance plans which can be factored into operational planning i.e. integrated operations. For more information see: https://www.greentechmedia.com/articles/read/behind-new-york-power-authoritys-digital-avatar-project-with-ge?utm_source=Daily&utm_medium=Newsletter&utm_campaign=GTMDaily.

[121] For more information see: https://www.metering.com/news/uk-ofgem-grid-funding-nic/.

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12. Network Revenue

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12. Network Revenue

12.1. Introduction

Our Final Plan has described the services we will provide (Chapter 6) and the cost of providing those services (Chapters 7 to 10). Our costs are referred to as 'building blocks' and are summed to determine total revenue (referred to as building block total revenue) in each year of the next (2018 to 2022) AA period. We recover this revenue through the prices (or tariffs) that we charge retailers for providing Ancillary Reference Services (ARS) and Haulage Reference Services (HRS).

This chapter sets out the total revenue and the proposed prices to apply over the next AA period.

12.2. Regulatory Framework

We are required to determine total revenue for each year of the next AA period as the sum of our forecast operating expenditure (opex) (Chapter 7), return on our capital base (Chapters 8, 9 and 10), regulatory depreciation (Chapter 9) and a forecast of the cost of tax (Chapter 10). Our total revenue can also increase or decrease depending on our performance against the Efficiency Benefit Sharing Scheme (EBSS) that applied in the current (2013 to 2017) AA period.

12.3. Stakeholder Engagement

We have reflected the outcomes of our stakeholder engagement program throughout this Final Plan, including across all aspects that input into determining building block total revenue. We also engaged on:

- our proposed price path, including by providing customers a view on the likely price movements over the next AA period; and on
- whether explicit consideration should be given to whether building block revenue provides sufficient cash flow to maintain the credit rating assumed by the Australian Energy Regulator (AER) in setting the cost of debt.

Key stakeholder feedback on these matters is set out in Table 12.1.

Table 12.1: Consideration of Stakeholder Feedback on our Revenue and Price Proposal

Draft Plan Stakeholder Question	Stakeholder Feedback[122]	Our Response to Feedback on the Draft Plan
Do you support our objectives of maintaining stable credit metrics and aligning revenue with underlying costs in setting our proposed price path? Would you prefer an alternate price path, and if so, on what basis?	While supportive of our proposed price path, some stakeholders questioned whether we could consider alternative options to satisfy the stated objectives of supporting credit metrics and ensuring prices equal underlying costs at the end of the next AA period.	We have reduced the price changes that apply from 1 January 2019 from 3.0% proposed in the Draft Plan to 2.5%, which more closely aligns with the growth in our asset base.
Do you consider that explicit consideration should be given as to whether a pricing proposal provides sufficient cash flow to maintain the credit rating assumed by the AER in setting the cost of debt? If so, how do you think this assessment should be done – for example, by considering the credit metrics against levels assumed by ratings agencies? If an adjustment to prices is required, how should this be undertaken – for example, through changes in capitalisation or depreciation?	Stakeholders considered that a consideration of financeability was reasonable, with adjustments only provided where a business was clearly below the required credit metrics over the AA period.	We have assessed the key credit metrics associated with our Final Plan and do not consider they are clearly below required thresholds throughout the next AA period. We therefore have not applied an explicit adjustment to our cash flows to support the financeability of the business.

Note: In this 'traffic light' table, green shading represents no change from the Draft Plan, orange shading represents a modification of the position outlined in the Draft Plan and red shading represents change from the Draft Plan.

12.4. Building Block Total Revenue

Building block total revenue includes revenue from providing ARS and HRS. As discussed in Chapter 14 we charge different prices in respect of ARS and HRS. We therefore need to determine the proportion of building block total revenue that applies to ARS and HRS, which we do by determining building block total revenue inclusive and exclusive of ARS.

As explained in Chapter 6, ARS are those services that are specifically requested by users. The forecast volume of ARS to be provided over the next AA period is explained in Chapter 13 while the derivation of the ARS prices is explained in Chapter 14. Table 12.2 sets out the ARS building block total revenue, which is determined by multiplying the forecast volume by the price of providing ARS in each year.

[122] Deloitte, *Stakeholder and Customer Feedback Report*, December 2016. Provided as Attachment 5.10 to this Final Plan.

Table 12.2: Forecast Revenue from Ancillary Reference Services, 2018 to 2022 ($nominal, million)

	2018	2019	2020	2021	2022
Meter Gas and Installation Test	0.01	0.01	0.01	0.01	0.01
Disconnection	0.83	0.85	0.88	0.91	0.94
Reconnection	0.43	0.44	0.45	0.47	0.48
Meter Removal	0.17	0.17	0.18	0.18	0.19
Meter Reinstallation	0.68	0.70	0.72	0.75	0.77
Special Meter Read – Metropolitan	1.37	1.41	1.45	1.50	1.55
Special Meter Read – Non Metropolitan	0.56	0.57	0.59	0.61	0.63
Total	**4.05**	**4.17**	**4.30**	**4.44**	**4.59**

Note: Totals may not add due to rounding.

Our Final Plan has set out the derivation of all the building blocks that are used to determine the building block total revenue, aside from the return on capital building block. This is determined by multiplying the rate of return (or weighted average cost of capital) of 5.28% (Chapter 10) by the opening capital base in each year of the next AA period (Chapter 9). The building block total revenue, inclusive and exclusive of ARS, is set out in Table 12.3.

Table 12.3: Building Block Total Revenue, 2018 to 2022 ($nominal, million)

	2018	2019	2020	2021	2022
Return on Capital	85.4	89.4	94.2	98.9	102.7
Return of Capital (Regulatory Depreciation)	41.5	47.6	50.7	45.2	49.9
Opex	68.8	71.2	73.8	76.5	79.5
Incentive Mechanism	13.8	7.1	5.5	-0.4	-
Cost of Tax	12.7	12.6	12.1	9.6	10.3
Building Block Total Revenue (including ARS)	**222.1**	**227.9**	**236.2**	**229.8**	**242.4**
Less ARS	4.1	4.2	4.3	4.4	4.6
Building Block Total Revenue (excluding ARS)	**218.1**	**223.7**	**231.9**	**225.4**	**237.8**

Note: Totals may not add due to rounding.

We recover the building block total revenue through the prices we charge customers for providing services. We are required to set our prices such that the total revenue we recover through prices is the same as the building block total revenue (put differently, so that we are no better or worse off if we recover the building block revenue or the actual revenue we recover from our prices). There are a series of percentage changes (or X factors) calculated to balance the net present value (NPV) of building block revenue and price revenue to ensure this objective is achieved, referred to as the price path.

The building block total revenue, price revenue and required percentage changes in prices are set out in Table 12.4. We have developed our price path in order to:

- provide for revenue growth that, to the extent possible, matches the growth in our capital base over the next AA period to ensure our revenue grows in line with our underlying costs; and
- to the extent possible given the first issue, to equate revenue with our underlying costs in 2022 (the last year of the next AA period) to limit any one-off adjustment to prices (either positive or negative) required from 1 January 2023 to equate price revenue with costs.

The first point is also consistent with assisting the business maintain/achieve stable credit metrics at levels assumed by the AER in setting the return on debt (see Section 12.4).

Table 12.4: Proposed Price Path, 2018 to 2022 ($nominal, million)

	2018	2019	2020	2021	2022
Building Block Revenue	222.1	227.9	236.2	229.8	242.4
Price Revenue	205.4	216.1	227.6	239.5	252.1
Real Price Path	**11.49%**	**2.45%**	**2.45%**	**2.45%**	**2.45%**

Note: The price path has been calculated as 2017 Tariffs x (1 + [Consumer Price Index]) x (1-X), which means a negative value corresponds to a price increase and vice versa for a positive value. This price path equates the present value of the building block revenue with the price revenue using the regulatory rate of return of 5.28%.

12.5. Financeability of a Pricing Decision

The AER assumes a certain credit rating (of BBB+/Baa1) when it sets the return on debt (as the assumed credit rating directly impacts borrowing costs/rates). We therefore consider that it is good regulatory practice to consider the overall outcome of a proposal/decision in light of this important assumption. We note that this type of analysis is undertaken by other regulatory bodies, including by the Office of Gas and Electricity Markets in the United Kingdom.

Specifically, we believe that we (and the AER) should consider whether our proposal (or in the case of the AER, its decision) provides sufficient revenue/cash flow for a business to achieve the assumed credit rating. To this end, stakeholders at our workshops on the Draft Plan believed:

> *"… a consideration of financeability during the regulatory review process to be reasonable, with adjustments only provided where a business was clearly below the required credit metrics over the regulatory period."* [123]

The credit rating agencies focus on the following two key ratios in making a decision on an appropriate credit rating for a business:

- *Funds from Operations (FFO) to debt* – which is defined as FFO divided by debt (and which measures the availability of cash flow to repay the balance of outstanding debt); and
- *FFO to interest* – which is defined as FFO plus interest divided by interest (and which measures the availability of cash flow to pay interest).

[123] Deloitte, *Stakeholder and Customer Feedback Report*, December 2016. Provided as Attachment 5.10 to this Final Plan.

FFO is calculated as total revenue less interest, opex and tax. Our conservative view is that the ratings agencies require a sustained FFO-to-debt ratio of at least 9% and a FFO-to-interest cover above 2.5. We also consider that the key focus of the credit rating agencies is on the FFO to debt ratio given the prevailing very low interest rate environment (making interest coverage a far easier constraint to achieve).

We have assessed the key credit ratios delivered by our Final Plan (see Table 12.5). This shows an average FFO to debt of 8.1% and FFO-to-interest of 2.8 over the next AA period. While average FFO to debt is below the 9% threshold required for a BBB+/Baa1 rating, the ratio is increasing over the next AA period. This reflects and supports our proposed price path explained in Section 12.4.

Table 12.5: Final Plan Key Credit Ratios, 2018 to 2022

	2018	2019	2020	2021	2022	Average
FFO to Debt	6.5%	7.5%	8.0%	9.1%	9.3%	8.1%
FFO to Interest Cover	2.5	2.7	2.8	3.0	3.1	2.8

Consistent with stakeholder feedback, we have not made an explicit adjustment to our cash flow as we do not consider this to be required (or at least the evidence wasn't clear as per feedback at the stakeholder workshops).

The credit ratios are, however, marginal, and as such, should be monitored closely as part of the decision-making process. Any such adjustment that might be required could include to[124]:

- vary the inflation adjustment that is applied to our capital base, with the lower inflation adjustment provided through increased revenue (and hence cash flow) in the next AA period; or
- shift the classification of capex to opex, which again increases the cash flow given that opex is recovered in the year it is incurred while capex is recovered over the longer term (up to 60 years).

Importantly, any such adjustment alters the timing of cash flow rather than the total amount of cash flow recovered by our business (that is, consumers are no better or worse off as a result of the adjustment over the medium to longer term).[125]

12.6. Summary

We recover our costs, or building block revenue, through the prices that we charge for providing network services. We have proposed to cut our network prices in Victoria and Albury by 11% (before inflation) on 1 January 2018 and increase prices thereafter in line with the growth in our capital base. This price path materially improves our ability to maintain stable credit metrics close to the levels assumed by the AER in setting our cost of debt allowance.

[124] This matter was discussed in more detail in Attachment 9.5 provided to the AER as part of our SA AA review process, which can be found here: http://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/australian-gas-networks-sa-access-arrangement-2016-21/revised-proposal.

[125] As part of the South Australian AA review process, we provided the AER with a report prepared by Incenta in response to the AER's Draft Decision. This report described the issue of financeability in greater detail and described how a financeability adjustment could be made. The report can be found at: http://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/australian-gas-networks-sa-access-arrangement-2016-21/revised-proposal (Attachment 9.7).

We consider that it is good regulatory practice to assess our plan (and subsequent AER decisions) to ensure that it delivers sufficient cash flows to maintain the BBB+/Baa1 credit rating assumed by the AER in setting the return on debt. We have done this and consider that there is some risk that the cash flows under this Final Plan are not sufficient to maintain the assumed credit rating. We have not made an adjustment as, consistent with stakeholder feedback, we are not clearly below required credit metrics.

We consider this analysis needs to be updated through the review of our AA proposal to ensure the financeability of the final decision, including to reflect any updates once the uncertainty from current legal reviews undertaken by other network businesses and the AER is resolved

13. Demand Forecasts

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13. Demand Forecasts

13.1. Introduction

This section outlines our forecasts of gas consumption and customer numbers (collectively referred to our demand forecasts) for the following customer groups:

- *Residential* – who are those customers that use gas for residential purposes;
- *Commercial* – who are our business customers who use less than 10 terajoules of gas each year (which equates to an annual retail gas bill of around $200,000 or less); and
- *Industrial* – who are our largest business customers.

Our gas demand forecasts are a key input into determining our growth capex and opex forecasts (the associated costs of connecting new customers to our network) as well as determining our prices (or Reference Tariffs), which are determined by dividing total revenue by the demand forecasts.

We have engaged an independent expert (Core Energy) to develop forecasts of gas consumption and customer numbers over the next (2018 to 2022) Access Arrangement (AA) period. The methodology applied to develop our demand forecasts is consistent with that recently approved by the Australian Energy Regulator (AER) for our South Australian network. This includes a consideration of key forecasting principles applied by the Australian Energy Market Operator (AEMO) to forecast gas demand.

13.2. Regulatory Framework

Our demand forecasts must be arrived at on a reasonable basis and must represent the best forecast or estimate possible in the circumstances.

13.3. Stakeholder Engagement

We engaged with stakeholders in respect of our demand forecasts; in particular, explaining the forecasting methodology applied and the key drivers of future demand. Stakeholders understood our approach to forecasting demand and acknowledged the same forecasting approach had been applied and accepted by the AER for our South Australian network. Stakeholders also sought transparency as to the key assumptions driving the forecast of demand, which assumptions are explained in this chapter and the report and supporting models by Core Energy (see Attachments 13.1 through 13.5).

The key stakeholder feedback received and our response to that feedback is set out in Table 13.1.

Table 13.1: Consideration of Stakeholder Feedback on our Demand Forecasts

Draft Plan Stakeholder Question	Stakeholder Feedback[126]	Our Response to Feedback on the Draft Plan
Do you consider our approach to forecasting demand to be reasonable?	There was general stakeholder support for the approach taken to demand forecasting, noting that it was consistent with the approach recently endorsed by the AER for our South Australian network. Stakeholders, however, questioned if history was a reliable indicator of future demand. It was discussed whether, instead of relying on past trends, the demand forecast should be broken down into its component drivers and forecast based on expectations of changes in these drivers over the next AA period. Examples provided included forecast changes in consumer preferences, behaviour, appliance efficiency, price and policy more generally. Stakeholders agreed with the approach of adjusting the historic trend for forecast changes in gas and electricity prices. Stakeholders were seeking confirmation that all assumptions would be transparent in our proposal.	The approach to forecasting demand has the flexibility to capture the impact of drivers of future demand that are not present in the historic demand data. In this regard we note that our forecasts reflect the future expectations of gas and electricity prices. Further, the forecasting approach has the flexibility to capture changes in policy or customer behaviour. However our expectations are that, over the forecast period to 2022, this will not significantly deviate from the consumer preferences and energy policies reflected in the historic data. We confirm that assumptions used to forecast demand will be transparent and identifiable in either this Final Plan or the report from Core Energy, which report comprises Attachment 13.1.

Note: In this 'traffic light' table, green shading represents no change from the Draft Plan, orange shading represents a modification of the position outlined in the Draft Plan and red shading represents change from the Draft Plan.

13.4. Forecasting Approach

Core Energy were engaged to develop gas consumption and customer number forecasts for residential, commercial and industrial customers for each tariff zone in Victoria and Albury. The approach to developing the forecast is consistent with that approved recently for our South Australian network. This includes a consideration of key forecasting principles applied by the AEMO to forecast gas demand.

Further detail on the approach to residential and commercial forecasts is provided in Section 13.4.1 and industrial in Section 13.4.2. Section 13.4.3 provides an overview of the key assumptions underpinning the forecasts.

126 Deloitte, *Stakeholder and Customer Feedback Report*, December 2016. Provided as Attachment 5.10 to this Final Plan.

13.4.1. Residential and Commercial Customers

There are around 650,000 residential and commercial customers that are currently connected to our network, which account for over 95% of the total revenue recovered. The forecast of gas demand for our residential and commercial customers is based on the following steps:

- remove the impact of weather and energy price movements from the historical consumption per connection of each customer group, which is then used to determine the base (or normalised) trend change in consumption per connection;
- adjust the historical trend consumption per connection for any new drivers or change in existing drivers that are not included in this historic trend, such as forecast movements in energy prices (gas and electricity);
- forecast the number of net customer connections, which is based primarily on the expected growth in new dwellings for residential customers and trend growth for commercial customers;
- multiply consumption per connection by connection numbers to forecast total demand for each customer group; and
- adjust for the impact of our marketing program to apply over the next AA period and for the removal of zero consuming meters.

We have prepared separate forecasts of the residential and commercial sectors as each customer group responds differently to the above drivers of demand.

13.4.2. Industrial Customers

While there are only around 300 industrial customers, they account for over half of the total gas demand on our network. Their demand is largely driven by prevailing economic conditions, with negligible sensitivity to variations in weather. Our industrial customers are charged on a capacity basis, and as such, we forecast capacity measured as the maximum amount of gas expected to be used within a single hour (referred to as gigajoules (GJ) of Maximum Hourly Quantity (GJ MHQ)).

The key steps taken to forecast capacity for our industrial customers include:

- identifying any known new connections, disconnections and expansions/contractions of capacity of existing customers, including through the use of surveys;
- survey industrial customers to learn their future intended gas demand; of the 300 industrial customers, ten responded to the survey;
- for those customers who did not respond to the survey, determine which customers historic demand was observed to have a statistically significant relationship with economic activity and apply an adjustment based on forecast economic growth;
- for the remaining industrial customers apply an adjustment based on historic trend changes in demand; and
- consolidate the above outputs to determine the industrial gas demand forecast.

13.4.3. Key Assumptions

Stakeholders considered it important that we are transparent in detailing the key assumptions used to prepare our demand forecasts. We agree with stakeholders, and to this point, present the following key assumptions and inputs used to forecast gas demand:

- our weather adjustment;

- forecasts of new dwelling construction (for the residential sector);
- the sensitivity of demand to movements in energy prices (referred to as the price elasticity of demand);
- the impact of our proposed marketing program; and
- the removal of zero consuming meters.

13.4.3.1. Weather Adjustment

Gas demand for our residential and commercial customers is materially impacted by weather. This reflects that our customers use relatively more gas when it is colder to heat their homes and businesses (and vice versa in times of warmer weather). It is therefore necessary to adjust the historic residential and commercial demand for weather to ensure the forecast starting point and historic trends relied upon to forecast gas demand are not unduly impacted by abnormal weather.

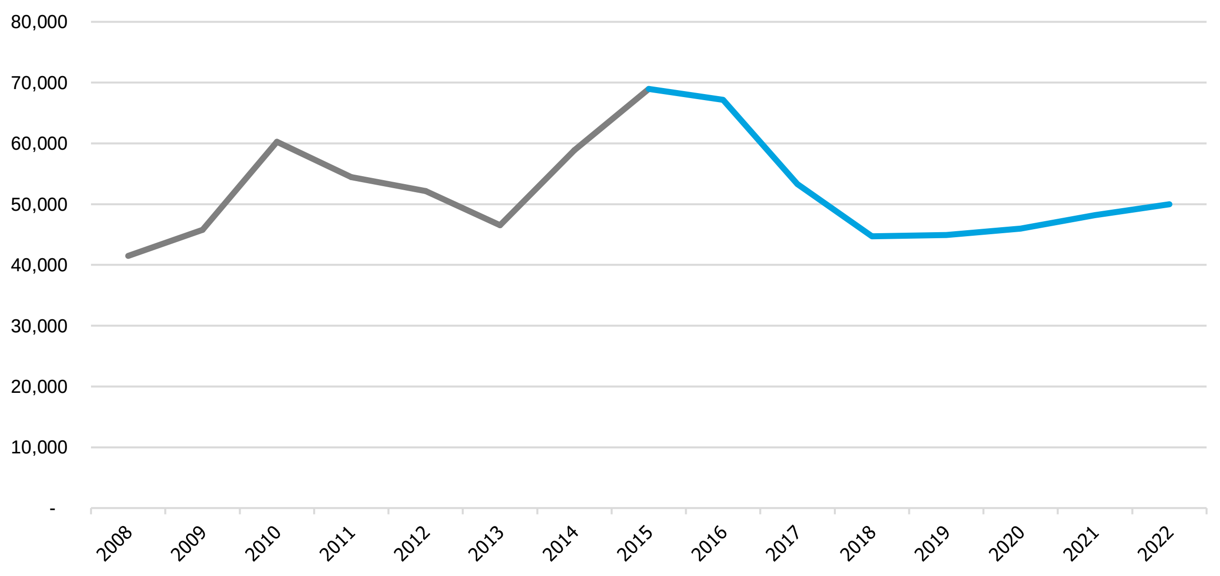
We have applied the same approach to adjust for weather as that used by AEMO, referred to as its Effective Degree Day (EDD312) weather standard, which approach enables us to determine the volume impact attributable to annual variances to weather relative to the EDD baseline. This volume impact is then removed from the historic consumption per connection trend to derive a weather normalised trend that is used for forecasting purposes.

13.4.3.2. Forecast New Dwelling Growth

The number of new residential connections expected over the next AA period is directly related to the forecast number of new dwellings in Victoria. This forecast has relied on independent forecasts of new dwelling commencements from the Housing Industry Association (HIA) as a basis for projecting new gas connections in Victoria. As dwelling forecasts were not available for the zone of Albury, connection growth was projected using historic trends in customer numbers.

In respect of Victoria, the HIA new dwelling forecast is strong currently, followed by a slowing of construction activity through to 2019 and then recovery towards to the end of the forecast period 2022. Figure 13.1 below shows the HIA forecast of dwelling construction.

Figure 13.1: Actual and Forecast Dwelling Commencements – Victoria



13.4.3.3. Future Prices and Price Elasticity

Stakeholders considered it appropriate that our demand forecasts incorporate the effect of future energy price changes. In this regard, Core Energy has projected retail gas and electricity prices over the next AA period (see Attachment 13.1). The key driver of retail gas prices in Victoria and Albury is the ongoing impact of the Liquid Natural Gas export facilities in Queensland, which facilities are yet to reach full export capacity.

Projected retail gas and electricity prices impact on gas demand through application of a measure of own-price elasticity and cross-price elasticity respectively, which are explained as follows:

- *Own-price elasticity* – which captures how changes in retail gas prices impacts consumption per connection, accounting for not only the current year impact but also the impact of price changes on consumption up to four years back (reflecting that customers will continue to respond to changes in gas prices in the years following the initial price change); and
- *Cross-price elasticity* – which captures how changes in retail electricity prices impacts consumption per connection, which is relevant given that gas can be substituted for electricity for all residential and most commercial applications.

In terms of the elasticity values, the forecast assumes those used in our recent South Australian AA review process, which values are:

- a lagged long-term-own-price elasticity of -0.3 for residential customers and -0.35 for commercial customers (which means a 1% increase in retail gas prices will result in a 0.3% and 0.35% decrease in average gas consumption per connection for residential and commercial customers respectively); and
- a long-term-cross-price elasticity of 0.1 (which means a 1% increase in retail electricity prices will result in a 0.1% increase in average gas consumption per connection).

The elasticities are reflected in the demand forecast as an adjustment to the historic trend decline in consumption per connection for the residential and commercial segments. The elasticities are also consistent with those used by AEMO in developing the gas forecast for the National Gas Forecasting Report (NGFR)[127] published in March 2016.

13.4.3.4. Impact of Marketing

As part of this Final Plan we are proposing an expanded marketing program (see Section 7.6.2.2 for more details on the proposed program). The expanded marketing program will result in new customers connecting to the network for the first time as well as existing customers connecting additional gas appliances. We have therefore made a post model adjustment to the connections and demand forecast to reflect the increases expected from the program.

13.4.3.5. Zero Consuming Meters

There are meters on our network for which there is no associated consumption. This situation may occur if a property is vacant or if a customer has ceased using gas. As at 30 June 2016, there were approximately 11,000 zero consuming meters on the Victorian and Albury networks, the majority of which around 85% are residential meters. Retailers are seeking to have these meters removed from the network to avoid network connection charges.[128]

We have therefore assumed all zero consuming meters are removed from the network by the close of 2018. This assumption impacts the total connection forecasts, incorporated as a post-

[127] AEMO, *National Gas Forecasting Report* March 2016, *NGFR Forecasting Methodology Information Paper,* pages 35-36.

[128] Retailers are required to pay supply charge for each metered site.

model adjustment to customer connections and consumption per connection forecasts, as total consumption remains constant, but the number of connections reduces thereby resulting in an increase in consumption per connection.

13.5. Residential Forecasts

As noted, our forecasts of residential gas demand are based on forecast customer numbers multiplied by forecast consumption per connection.

13.5.1. Residential Customer Growth

Residential net customer growth is forecast to be 2.0% per year, which is lower than the historic growth rate of 2.4%. This is due to a slowing of new dwelling construction in Victoria and Albury over the next AA period as forecast by the HIA.

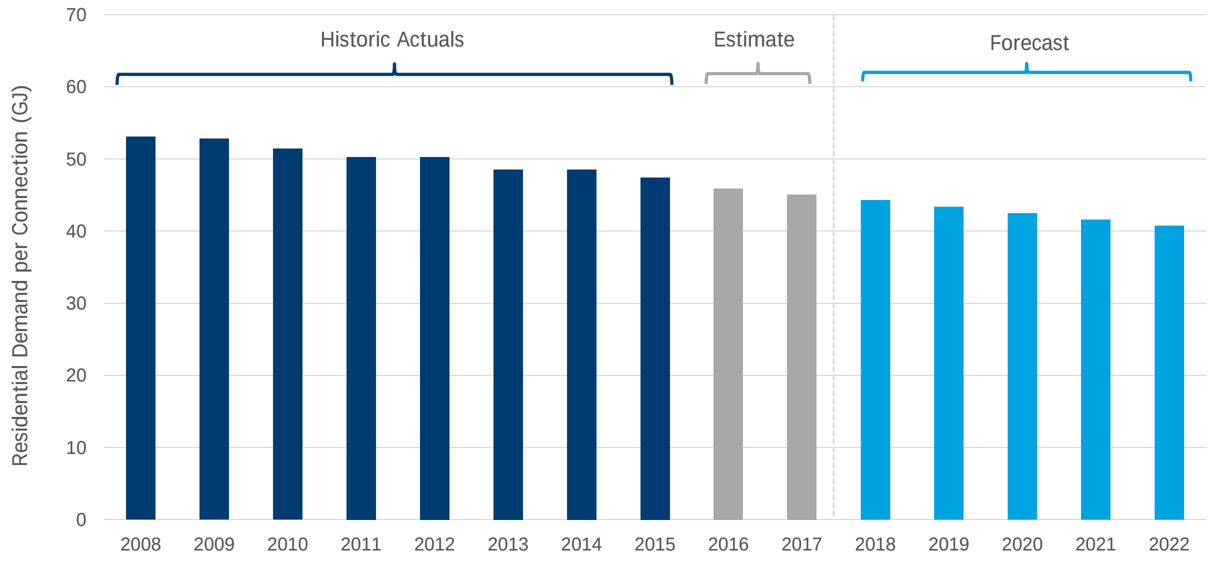
13.5.2. Residential Consumption per Connection

There has been a long-term decline in average residential consumption per connection across all of our networks, including in Victoria and Albury where consumption per connection has fallen from around 53 GJ per connection in 2008 to 47 GJ in 2015 (a decline of 1.5% per year). The key drivers of this decline include improved appliance and dwelling efficiency and the substitution of gas appliances for their electric equivalent (for example, substituting gas heating for electric reverse cycle air-conditioning).

The historic trend rate of decline in consumption per connection is forecast to increase to 2.2% per year, resulting in a demand per connection in the final year of the next AA period of just over 40 GJ per year. The decline in consumption per connection is in part due to the forecast increase to wholesale gas costs (see Attachment 13.1, Section A2). Importantly, the decline in consumption per connection is offset by the positive impact of our expanded marketing program.

The forecast decline is less than our expectations for our South Australian network. In its recent review of the South Australian network, and consistent with our own expectations, the AER estimated a rate of decline of 3.5% per year in consumption per connection, which also largely reflected the impact of increases to wholesale gas costs. While the decline in Victoria and Albury is less than in South Australia, the decline is a consistent theme across all of our networks in Australia.

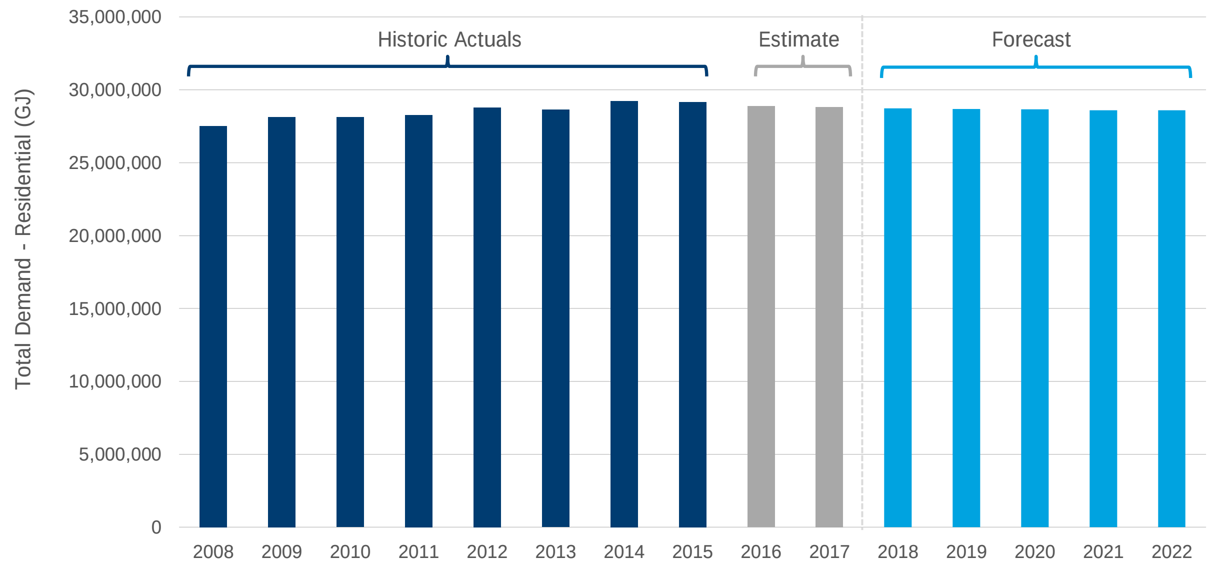
Figure 13.2: Residential Consumption per Connection (GJ)



13.5.3. Residential Demand Forecasts

Overall, residential gas demand is forecast to be relatively flat over the next AA period, with reductions in consumption per connection offset by net customer growth. Total residential gas demand is forecast to decrease by around 0.2% per year over the next AA period. We note that our demand forecast is conservative relative to AEMO's forecast decline in annual demand for Victoria of 0.7% per year.[129] Figure 13.3 shows the total gas demand from 2008 to 2022 (the final year of the next AA period).

Figure 13.3: Residential Demand (GJ)



[129] AEMO, *National Gas Forecasting Report,* March 2016 page 40.

The residential gas demand forecasts are shown in Table 13.2, including customer numbers, consumption per connection and total demand.

Table 13.2: Residential Demand Forecast

	2018	2019	2020	2021	2022
Net Customer Numbers	648,388	661,344	674,447	687,772	701,320
Consumption per Connection (GJ)	44.3	43.4	42.5	41.6	40.8
Demand (TJ)	**28,732**	**28,680**	**28,667**	**28,605**	**28,587**

Note: Totals may not add due to rounding.

13.6. Commercial Forecasts

Like residential, forecasts of commercial gas demand are based on forecast customer growth multiplied by forecast consumption per connection.

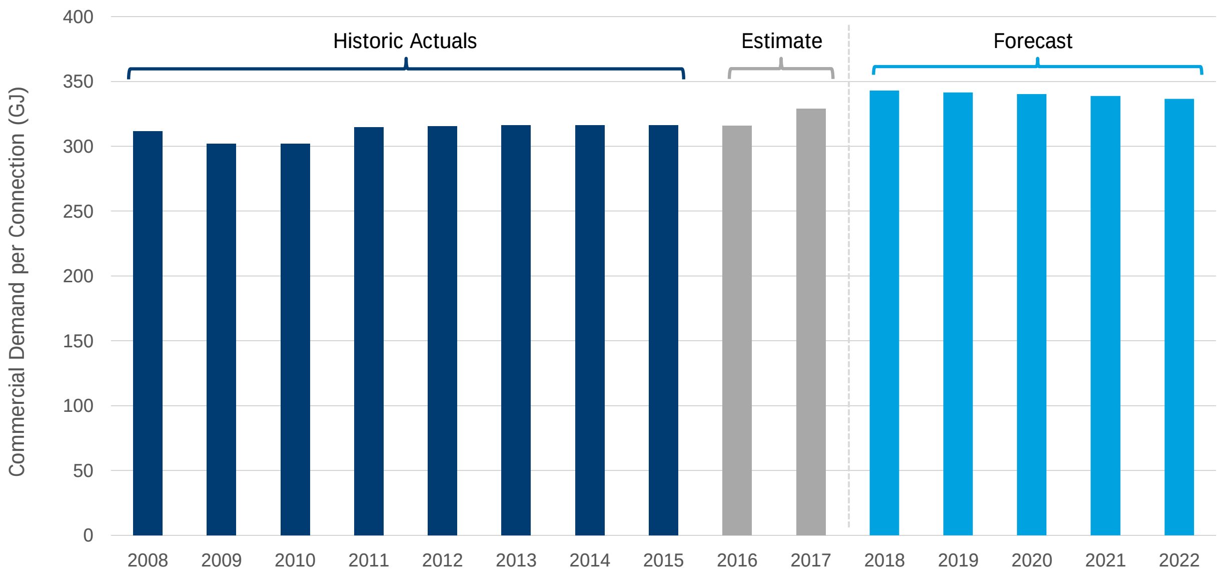
13.6.1. Commercial Customer Growth

Commercial net customer growth is forecast to be 0.6% per year over the next AA period, which is the same growth rate that has occurred over the past five years.

13.6.2. Commercial Consumption per Connection

The consumption per connection of commercial customers has increased by an average of 0.2% per year between 2008 and 2015. As with residential, forecast consumption per connection will be impacted by the future price of wholesale gas, which price increase will result in consumption per connection falling to negative 0.5% per year. This is shown in Figure 13.4.

Figure 13.4: Commercial Consumption per Connection (GJ)



13.6.3. Commercial Demand Forecasts

We are forecasting total commercial demand to increase by 0.2% per year over the next AA period. The growth in demand is largely attributable to commercial connection growth of 0.7% per year, offset by consumption per connection falling by 0.5% per year. Figure 13.5 shows the total demand from 2008 to 2022 incorporating customer numbers, consumption per connection and total gas demand.

Figure 13.5: Commercial Demand (GJ)

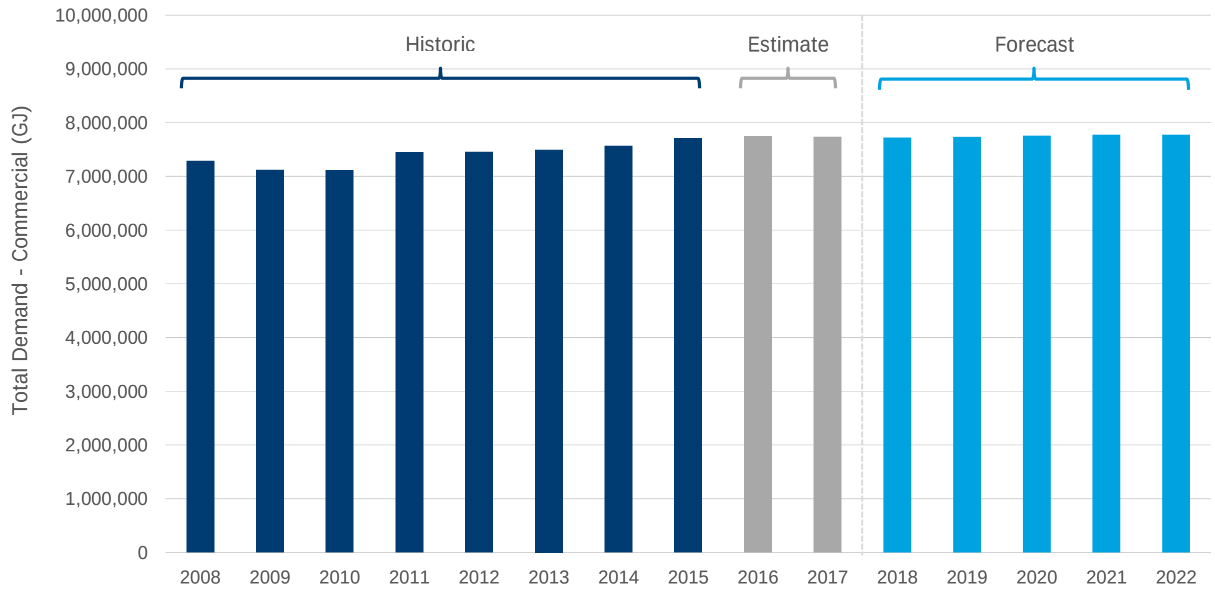


Table 13.3: Commercial Demand Forecast

	2018	2019	2020	2021	2022
Net Customer Numbers	22,511	22,658	22,806	22,954	23,103
Demand per Connection (GJ)	343.0	341.5	340.3	338.9	336.7
Demand (TJ)	**7,722**	**7,737**	**7,760**	**7,779**	**7,778**

Note: Totals may not add due to rounding.

13.7. Industrial Forecasts

Industrial demand is forecast to marginally increase by 0.1% per year over the next AA period, reflecting survey information received from industrial customers on their future demand expectations, forecasts of economic activity[130] as well as the continuation of existing historic trends. This is less than the historic eight-year trend decline of -1.7% per year.

The primary reason for the increase from the historic trend decline is the fact the historic trend for the total industrial segment was driven by the closure of two of our largest customers in 2012 and

[130] See Table 7.13 of the Core Energy Gas Demand Forecast Report provided as Attachment 13.1.

2013, which customers accounted for nearly 20% of our industrial load. Core Energy have reviewed our remaining largest customers and do not expect the same shutdowns to occur.

The industrial demand history and forecast is shown in Figure 13.6 and Table 13.4 below.

Figure 13.6: Industrial GJ MHQ

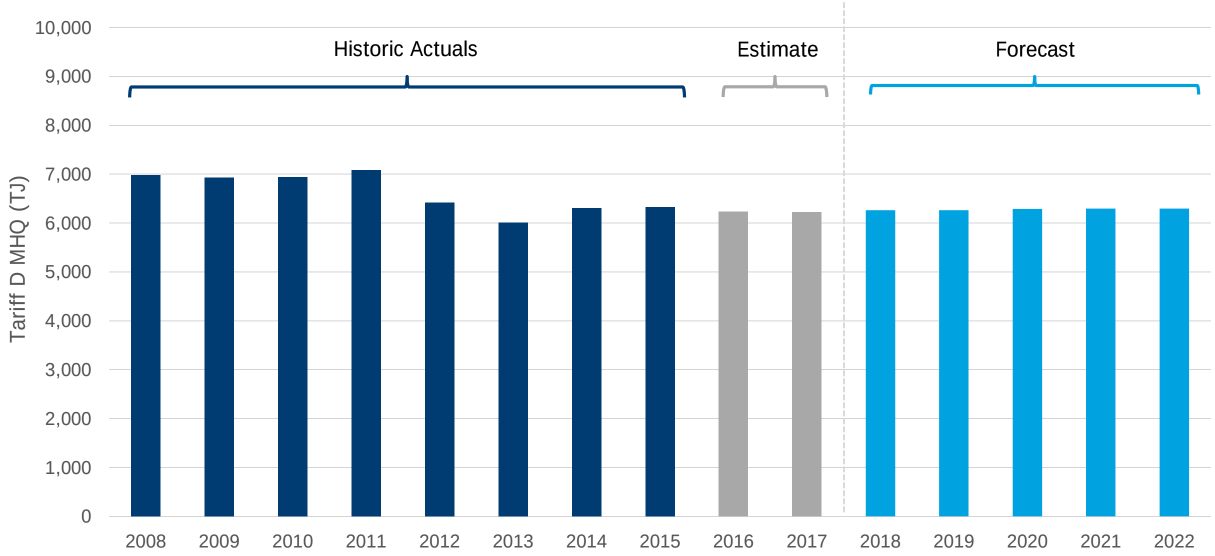


Table 13.4: Industrial GJ MHQ Forecast

	2018	2019	2020	2021	2022
GJ MHQ	6,260	6,261	6,291	6,293	6,295

13.8. AEMO Forecasts

AEMO produces annual forecasts of gas demand for the east coast gas market of Australia in the National Gas Forecasting Report (NGFR), the most recent report published in March 2016. While the forecast includes expectations of Liquefied Natural Gas (LNG) exports and gas required for electricity generation, sectors not relevant to a gas distribution network, AEMO also produces forecasts for the less-than-10 terajoule segment (i.e. our residential and commercial segment) as well as the industrial segment.

The methodology used to develop the forecasts is consistent with that adopted by Core Energy, each method taking into account the impact on gas demand of future retail price expectations[131]. Both AEMO and our forecasts are predicting a decline in total demand for the residential and commercial segment, with AEMO predicting a sharper decline of 0.7% per year compared to Core Energy's more conservative 0.2% per year.

We consider the similarity of our forecasts relative to the AEMO expectation of future gas demand over the next AA period supports the reasonableness of our estimates of future gas consumption across our network.

[131] Core Energy's retail forecast is for the geographic area covered by our networks, while AEMO necessarily use a Victorian wide forecast. Otherwise the retail gas price forecasts are on a consistent basis.

13.9. Ancillary Reference Services

Ancillary Reference Services (ARS) comprise services we provide for special meter reads, disconnections, reconnections, meter and gas installation tests, meter removal and meter reinstallation. These forecasts are based on an estimate of those incurred in 2016 and are escalated in line with our operating expenditure (opex) forecast over the next AA period, noting that our ARS form part of the 2016 base year opex.

Table 13.5: Ancillary Reference Service Forecasts

	2018	2019	2020	2021	2022
Meter and Gas Installation Test	61	61	62	62	63
Disconnection	11,638	11,696	11,763	11,846	11,949
Reconnection	5,134	5,160	5,189	5,226	5,271
Meter Removal	1,653	1,661	1,671	1,682	1,697
Meter Reinstallation	6,692	6,725	6,763	6,811	6,870
Special Meter Read – Metropolitan	150,016	150,765	151,627	152,698	154,022
Special Meter Read – Non-Metropolitan	45,107	45,332	45,591	45,913	46,311

13.10. Summary

Our gas demand forecasts have been developed using a methodology consistent with that used by the AER for our South Australian network. The residential forecasts are driven by expected new dwellings growth in Victoria and Albury, as provided by the Housing Industry Association. Both residential and commercial forecasts are also impacted by the increase in wholesale gas costs driven by the ongoing development of the gas export industry in east coast Australia.

Our industrial forecasts are largely based on the historical trend exclusive of the closure of our largest customer over the current AA period.

We have also assessed our forecasts against those prepared separately by AEMO for the NGFR. Both our forecasts and the NGFR have similar expectations of future gas demand, with our forecast decline in residential and commercial gas demand of 0.2% per year being more conservative than the decline expected by AEMO of 0.7% per annum.

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14. Network Pricing

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14. Network Pricing

14.1. Introduction

Chapter 12 set out the revenue that we are proposing to recover over the next (2018 to 2022) Access Arrangement (AA) period. We recover this revenue through the prices (or tariffs) that we charge retailers for providing reference services (see Chapter 6). This chapter sets out the proposed prices to apply over the next AA period and how those prices are proposed to be adjusted during the AA period.

We are not proposing any significant change to the prices that have applied over the current (2013 to 2017) AA period.

14.2. Regulatory Framework

Our prices are required to reflect the underlying cost of providing services to our customers. Our prices are also required to lie between the avoidable and stand-alone cost of providing services, take into account transaction costs and provide efficient price signals.

14.3. Current Pricing Structure

The current pricing structures have been in place since 2013 and are shown in Table 14.1. There are four different pricing zones in Victoria (Central, Northern, Murray Valley and Bairnsdale) and one pricing zone in Albury (which we are required to maintain).[132] Each zone comprises residential, commercial and industrial prices.

Prices for residential and commercial customers consist of a number of volumetric (or consumption) based charging parameters (in dollars per GJ per day) and a fixed supply charge (in dollars per day). Prices for our industrial customers are capacity based and consist of a number of banded charging parameters (in dollars per GJ of Maximum Hourly Quantity (MHQ)). All prices decline as usage increases to promote better network utilisation.

Table 14.1: Charging Parameters by Customer Type

Residential (Tariff R)	Commercial (Tariff C)	Industrial (Tariff D)
Fixed Charge	Fixed Charge	0 – 10 GJ MHQ
0 – 10 GJ	0 – 18 GJ	Next 40 GJ MHQ
10 – 18 GJ	18 – 201 GJ	Additional GJ MHQ
>18 GJ	201 – 500 GJ	
	>500 GJ	

[132] In November 2015, AGN applied to consolidate the Victorian and Albury Access Arrangements and on 23 March 2016 the Australian Energy Regulator (AER) directed Australian Gas Networks Limited to do so. As a condition of this consolidation, the AER specified that Albury remain a separate tariff zone under the combined AA for the next AA period.

14.4. Stakeholder Engagement

We sought feedback on the structure of our prices through our stakeholder engagement program. We initially consulted our customers and our Retailer Reference Group (RRG), who provided the following feedback:

- *Customers* – who indicated a preference for a greater reliance on prices that varied with usage (rather than prices that remained relatively fixed regardless of usage); and
- *RRG* – who indicated a preference for simplifying and consolidating prices in order to avoid unnecessary transaction costs.

We reflected this feedback in our Draft Plan, where we proposed to maintain our current variable pricing structures and sought to align prices across our three largest pricing zones in Victoria.[133] Our analysis on price alignment showed that prices in one of the Victorian zones would slightly increase despite our proposed 11% average price cut to apply from 1 January 2018.

We did not receive any feedback on our proposal to maintain the current variable price structures. At our stakeholder workshops, concern was raised that one group of customers would not receive the benefit of our proposed price cut and it was questioned whether this was justified by lower transaction costs. We agree with this feedback and have decided not to proceed with this proposal.

To simplify prices, the RRG also indicated a preference to remove the declining pricing bands in favour of a single pricing band. We did not support this initiative in our Draft Plan on the basis that the existing declining pricing bands aligned with our obligation to promote efficient use of the network. We did not receive any direct feedback on this matter in response to the Draft Plan.

Table 14.2 summarises the stakeholder feedback received on our prices and how we have responded to this feedback.

133 The Albury tariff zone could not be considered for alignment because one of the conditions of the consolidation of the Victoria and Albury AA is that Albury must be kept as a separate tariff zone.

Table 14.2: Consideration of Stakeholder Feedback on our Prices

Draft Plan Stakeholder Question	Stakeholder Feedback[134]	Our Response to Feedback on the Draft Plan
Do you agree with our proposed pricing structures, including our decision to align prices across the three Victorian zones of Central, Northern and Murray Valley and our decision not to consolidate price bands?	Stakeholders questioned whether it was appropriate to provide price decreases to all customers aside from those in the northern region. Stakeholders questioned certain aspects of our reasoning for aligning tariffs, including the expected reduction in transaction costs. Support for this initiative was not strong among stakeholders. We did not receive any feedback in response to our decision not to consolidate pricing bands.	We have decided not to align pricing zones from 1 January 2018 in response to stakeholder feedback. We will further consider this initiative, and if pursued, seek alignment over a longer time period. We have also maintained our decision not to consolidate pricing bands.
Do you consider that there is an appropriate split between our fixed and variable charges?	Stakeholders questioned whether, despite the preferences stated by our customers, a greater proportion of cost recovery should come from fixed charges. This reflected the largely fixed cost nature of providing reference services.	We have maintained our decision in the Draft that the declining price bands better align with our obligation to set efficient price structures relative to a single price band. This decision was supported by our customers in our second round of customer workshops.

Note: In this 'traffic light' table, green shading represents no change from the Draft Plan, orange shading represents a modification of the position outlined in the Draft Plan and red shading represents change from the Draft Plan.

14.5. Allocation of Total Revenue

As described in Chapter 6, we provide both Haulage Reference Services (HRS) and Ancillary Reference Services (ARS). ARS relates to specific services requested by a retailer, such as to undertake an additional (or special) meter read or to remove a meter from a customer site. Prices are charged to the retailer that requested the ARS.

The HRS accounts for the majority (98%) of our revenue/costs (see Chapter 12). The two HRS we are proposing to provide include:

- *Volume Haulage Service* – this service provides for the delivery of gas to those customers using less than 10 terajoules (TJ) of gas per annum and includes the reading of meters every two months. There is a separate price for residential customers and commercial customers (see Table 14.1);
- *Demand Haulage Service* – this service provides for the delivery of gas to those customers using more than 10 TJ per annum and includes reading the meter every month (see Table 14.1).

We have developed a cost allocation model (CAM) to allocate costs to the above HRS (see Attachment 14.1). The CAM allocates the HRS building block revenue set out in Chapter 12 to each pricing category on the basis of a number of different cost allocators, which include allocators based on asset values, customer numbers and consumption. The allocators selected

[134] Deloitte, *Stakeholder and Customer Feedback Report*, December 2016. Provided as Attachment 5.10 to this Final Plan.

reflect the best estimate of the cost to Australian Gas Networks Limited (AGN) of servicing each HRS.

We have not changed the approach to allocating costs to HRS for the next AA period relative to the approach approved by the Australian Energy Regulator (AER) for the current AA period.

14.6. Proposed Prices for Haulage Reference Services

We are proposing to maintain the existing price categories and structures over the next AA period. We consider that our current price categories and structures are consistent with our obligations to minimise transaction costs and to provide efficient price signals to network users. This section discusses the number of tariff classes that we propose and the structure of those tariff classes. A further assessment of our prices against our obligations is provided in Attachment 14.2.

14.6.1. Pricing Categories

Consistent with our obligations, we consider our current pricing categories group together customers on an economically efficient basis.[135] In particular, our pricing categories have been developed to ensure that customers with similar characteristics (and therefore cost drivers) are allocated to the same pricing category. In doing so, we have considered the following key characteristics:

- the need to group together customers with similar usage profiles; and
- the location of the customers on the distribution network.

With regard to the first point, and as shown in Table 14.1, we consider that the key customer types on our network are residential (Tariff R), commercial (Tariff C) and industrial (Tariff D). We have grouped these customers based on where they are located on the network. The tariff zones in Victoria and Albury are as follows:

- *Central Zone* – encompasses the city of Melbourne, the inner to outer north western suburbs of Melbourne, as well as the outer south eastern suburbs of Melbourne to Longford in the Gippsland;
- *Northern Zone* – is adjacent to the northern parts of the Central Zone and extends to the southern edge of the Murray Valley (Victoria) and Albury zones; it includes the towns of Echuca, Shepparton, Wangaratta and Wodonga;
- *Murray Valley (Victoria) Zone* – which covers the towns of Chiltern, Rutherglen, Yarrawonga and Strathmerton on the Victorian side of the Murray River;
- *Bairnsdale Zone* – which covers the towns of Bairnsdale and Paynseville located in south-eastern Victoria; and
- *Albury Zone* – which is centered on Albury on the New South Wales side of the Murray River.

There are separate residential and commercial prices for each of the above tariff zones. This is also the case for industrial prices, although the central and northern tariff zones are combined. In addition, there is a tariff zone for Albury that applies to residential, commercial and industrial customers. In total, there are 14 different pricing categories on our networks (see Table 14.3).

[135] Rule 94(2)(a), as detailed in Attachment 1.1 to this Final Plan.

Table 14.3: Victoria and Albury Price Categories

Price Category	Residential (Tariff R)	Commercial (Tariff C)	Industrial (Tariff D)
Tariff Zone	Central	Central	Northern and Central
	Northern	Northern	Murray Valley
	Murray Valley	Murray Valley	Bairnsdale
	Bairnsdale	Bairnsdale	Albury
	Albury	Albury	

As noted earlier, our RRG questioned whether we could reduce the number of prices that apply across Victoria and Albury. Specifically, the RRG asked whether we could make the current prices simpler by aligning prices in the Central, Northern, Murray Valley and Bairnsdale zones into a single price. In our Draft Plan we assessed the impact of aligning prices in all zones aside from in Bairnsdale, as these prices were recently approved on the basis that a premium apply. We noted:

> *"The effect of applying the same price, which includes our proposed overall price cut of 11%, is that our network charge will fall in all zones aside from customers in the Northern zone. The increase for customers in the Northern zone is however small, at $1.00 and $17.70 per year for residential and commercial customers respectively."* [136]

We supported the proposal by the RRG to align prices across the three Victorian zones on the basis that this would be simpler and would therefore reduce transaction costs (although we didn't assess this). Feedback from our stakeholder workshops on the Draft Plan did not consider it to be fair that all customers would benefit from our proposed price reduction aside from those located in the Northern zone:

> *"Stakeholders questioned whether it was appropriate to provide price decreases to all customers aside from those in the northern region. Stakeholders questioned certain aspects of the reasoning provided by AGN for aligning its tariffs, including the unsupported reduction in transaction costs. There was not strong support from stakeholders with respect to tariff alignment."* [137]

Having consideration of the above feedback, we have decided against aligning pricing zones from 1 January 2018, but will instead maintain the current pricing zones. This decision was supported by our customers in our secondary customer workshops held just prior to developing this Final Plan.[138]

14.6.2. Pricing Structures

This section discusses the proposed price structures set out in Table 14.1. In short, we are not proposing any change to our existing price structures.

[136] Our Draft Plan is provided as Attachment 1.2 to this Final Plan (see page 86).

[137] Deloitte, *Stakeholder and Customer Feedback Report,* December 2016. Provided as Attachment 5.10 to this Final Plan.

[138] As described in Chapter 5, in October 2016, we went back to customers originally consulted in March 2016 to describe what we heard from them initially and how their feedback had been incorporated into our Plans. Deloitte was engaged to facilitate and report on this engagement, its report is provided as Attachment 5.10 to this Final Plan.

14.6.2.1. Residential and Commercial Customers

Both the residential and commercial pricing bands (or components) decrease as customer usage increases (often referred to as declining block tariffs). This pricing structure:

- reflects the relatively low marginal cost associated with increasing the supply of gas to a customer; and
- encourages greater network utilisation, which is part of the package of measures that we use to address the observed long-term decline in demand per connection (see Chapter 13).

This pricing approach incentivises efficient utilisation of our networks and helps us remain price competitive with electricity.

The volumetric price bands account for around 73% and 90% of the average residential and commercial distribution charge respectively. We believe that the level of cost recovery from the variable bands is consistent with feedback from our customer workshops, where 74% of participants supported a high to very high degree of variability in their gas bill in line with their gas usage.[139]

Consistent with seeking simpler pricing structures, our RRG indicated a preference to remove the declining pricing bands in favour of a single pricing band. We did not adopt this proposal in our Draft Plan on the basis that we consider the declining pricing bands are more consistent with our obligations to promote the efficient use of the network (as declining price bands encourage greater network utilisation).

Whilst we do not consider the number of bands to be overly complex, we did consider consolidating the first two commercial price bands to simplify the tariff structure. We have, however, also decided against this option on the basis that this would result in a significant difference in network charges between residential and commercial users of the same size, which is not consistent with our underlying costs.

14.6.2.2. Industrial Customers

The prices for our industrial customers are based on the maximum usage of that customer at any point in time measured typically over the past year (referred to as capacity based prices). Capacity based prices encourage industry customers to have a smooth (or flat) usage profile as opposed to a ‘peaky’ profile. A flatter usage profile will lower gas network costs and improve network utilisation as the size (or capacity) of the network does not have to accommodate short-term increases in usage.

Like residential and commercial customers, the industrial pricing band decreases as capacity increases, which is again designed to encourage greater network utilisation (thereby lowering average costs to all customers).

14.6.3. Customer Impact

As explained in Chapter 12, we are proposing an 11% average price cut (before inflation) on 1 January 2018 across all customers. We have also explained in this chapter that we are proposing to maintain the same allocation of costs and pricing structures to all customers. This therefore means that all customers will receive, on average, an 11% reduction in their distribution charge.

In its submission to our Draft Plan, Jemena Gas Networks noted:

[139] Further information on our stakeholder engagement program is provided in Chapter 5.

> *"We found customers had strong interest in safety and reliability, but were also keen to understand what the plan meant for their bills. We note that AGN has provided a headline figure of an 11% cut in prices on 1 January 2018. We found that customers are aware that they are not homogenous and valued understanding price breakdowns by individual cohort (residential, commercial and industrial). We think there would be value in providing price impacts broken down by these cohorts as part of AGN's 1 January 2017 proposal."* [140]

The average fall in distribution charges on 1 January 2018 for each tariff zone is outlined in Table 14.4. The weighted average decrease for our residential, commercial and industrial gas distribution charges is $40, $185, and $3,698 respectively. Attachment 14.2 and our AA Document sets out the proposed prices to apply from 1 January 2018.[141]

Table 14.4: Average Decrease in the Annual Charge to Customers from 1 January 2018 ($nominal)

Average Customer Saving	2017 Average Annual Charge ($)	2018 Average Annual Charge ($)	Saving ($)	Saving (%)
Residential				
Central	364.4	322.5	41.9	11.5%
Northern	319.7	283.0	36.7	11.5%
Murray Valley	286.9	253.9	33.0	11.5%
Bairnsdale	468.5	414.7	53.8	11.5%
Albury	293.0	259.3	33.7	11.5%
Commercial				
Central	1,350.7	1,195.5	155.2	11.5%
Northern	1,005.4	889.8	115.5	11.5%
Murray Valley	932.6	825.4	107.2	11.5%
Bairnsdale	3,759.5	3,327.6	432.0	11.5%
Albury	1,005.3	889.8	115.5	11.5%
Industrial				
Central	23,243.6	20,572.9	2,670.7	11.5%
Northern	30,387.9	26,896.4	3,491.6	11.5%
Murray Valley	49,038.7	43,404.1	5,634.5	11.5%
Bairnsdale	18,922.2	16,748.0	2,174.2	11.5%
Albury	39,316.9	34,799.4	4,517.5	11.5%

140 Jemena Gas Networks, *Australian Gas Networks Draft Plan – Jemena Submission*, 16 August 2016. Provided at Attachment 5.8 to this Final Plan.

141 These annual charges have been calculated based on the average annual consumption in 2015 for each of the tariff zones and classes. More specifically the average consumption for residential commercial and industrial customers (MHQ) respectively are Central: 51GJ, 335GJ and 20GJ; Northern: 47GJ, 253GJ and 28GJ; Murray Valley: 37GJ, 199GJ and 40GJ; Bairnsdale: 30GJ, 813GJ and 8GJ; and Albury: 45GJ, 302GJ and 45GJ.

14.7. Proposed Prices for Ancillary Reference Services

We propose to maintain the number, structure and level (in real terms) of the prices charges in respect of ARS (see Table 14.5).

Table 14.5: Forecast Tariffs for Ancillary Reference Services ($nominal)

Ancillary Reference Service	Tariff
Disconnection	$71.0
Reconnection	$82.0
Meter Gas and Installation Test	$214.0
Meter Removal	$100.0
Meter Reinstallation	$100.0
Special Meter Read – Metropolitan	$9.00
Special Meter Read – Non Metropolitan	$12.3

14.8. Price Variation Mechanisms

We are allowed to vary our prices over the next AA period in accordance with procedures approved in our AA Document (referred to as approved price or tariff variation mechanisms). We are proposing price variation mechanisms in the next AA period that are similar to that applying in the current AA period. In particular, we are proposing:

- to maintain the current annual price variation mechanism, including the form of price control;
- to introduce the adjustment factor formula, to include the licence fee factor and pass through adjustment factor formulae;
- to increase the current rebalancing control constraint and method;
- to introduce the annual update to the return on debt, which implements the annual update to the return on debt building block required as a result of the adoption of a trailing average approach to determining the cost of debt;
- to maintain administrative processes for the approval of variations to prices;
- to provide scope to introduce new tariffs during the next AA period; and
- to maintain the same ability to adjust prices in response to certain defined (and unexpected) events (referred to as Cost-Pass-Through events).

These matters are discussed in the remainder of this chapter.

14.8.1. Form of Price Control

We are proposing to maintain the same form of control in respect of HRS that applies in the current AA period. This control places a constraint on the overall average movement in prices from one year to the next (referred to as a weighted average price cap, or WAPC).[142] The constraint allows average prices to increase by the annual change in the Consumer Price Index (CPI) less the X-factor (as determined in Chapter 12) plus an adjustment factor (see Section 14.8.2).[143]

This price cap form of price control is therefore applied to average prices rather than the total revenue that we can recover. This provides a stronger incentive on the business to increase customer connections and usage relative to a revenue cap. This is because our revenue will increase as the number of customers connected to our network and/or usage increases, whereas the revenue recovered under a revenue cap does not vary with increased usage.

We consider the incentive to increase usage under a price cap is consistent with the growth incentive that applies to a gas distribution network more generally. This reflects that gas is a fuel of choice for most applications (all applications in the case of residential customers). The price cap form of control therefore complements our:

- pricing structures discussed earlier in this chapter, particularly our declining price bands that are aimed at encouraging greater network usage/utilisation; and
- marketing initiatives that are aimed at increasing customer connections and network usage (see Chapter 7).

Both initiatives, by encouraging greater network usage, will lower prices to existing customers. This is because prices are determined by dividing building block total revenue (as derived in Chapter 12) by total network usage (as derived in Chapter 13). This means that prices will fall as usage increases.

The price control formula forms part of Annexure D of the AA Document and is described in more detail in Attachment 14.2.

14.8.2. Adjustment Factor

The adjustment factor is used in both the price control formula (as described in the previous section) and the rebalancing control formula (as described in the following section). This factor allows for the following pass through adjustment amounts to be recovered from or returned to our customers:

- the annual licence fees charged to AGN by the Victorian government and the New South Wales government;
- the Energy Safe Victoria (ESV) levy charged to AGN by the Victorian government;
- any pass through amount approved by the AER;
- any costs incurred by AGN in connection with a carbon emission scheme (such as the Carbon Safeguard Mechanism under the National Greenhouse Energy Reporting Act 2007; and
- any network innovation allowance expenditure approved by the AER.

Historically, the licence fee was allowed for in the Licence Fee Factor and the pass through amount was recovered by the Pass Through Adjustment Factor. We propose to consolidate the adjustments to the reference tariff to one formula to simplify the tariff variation mechanism. This formula is provided in Attachment 14.2 and also forms part of Annexure D of the AA Document.

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142 The WAPC is a form of tariff basket control, and as such, is consistent with Rule 97(2)(b) of the NGR.

143 Consistent with the current AA period, we are proposing to increase ARS by the CPI only.

14.8.3. Rebalancing Control Mechanism

The rebalancing control provides greater flexibility to adjust prices from one year to the next than allowed for by the price control on its own. The rebalancing control allows average prices for each of the 14 pricing categories set out in Table 14.3 to change by a fixed percentage above that allowed for by the price control.

The current rebalancing control is set at 2% (before inflation). We are proposing that the rebalancing control is changed to allow for the additional movement (beyond the CPI, the X factor and Licence Fee factors) for each pricing category to 5% (before inflation). We note that this will provide greater flexibility to address matters as they arise during the AA period, such as the potential alignment of prices discussed in Section 14.6 should this be required over the next AA period.

The rebalancing control formula forms part of Annexure D of the AA Document and is explained in more detail in Attachment 14.2.

14.8.4. Price Variation Process

We are proposing a consistent approach to that applying in the current AA period to varying prices in respect of the annual price adjustments that are to be made over the next AA period. These annual price adjustments are required to account for the annual change in inflation and the applicable X-factor for each year and enables us to recover our allowed building block revenues (as determined in Chapter 12).

In summary, we will notify the AER in respect of any variations to our prices at least 50 business days before those prices are proposed to come into effect. The notification to the AER will continue to provide an explanation of how the proposed variations comply with the price control and rebalancing control. We will also continue to publish our prices, including our pricing proposals, on our website.

14.8.5. Introducing New Prices

We are keen to allow for the ability to introduce new prices, should this be required, over the next AA period. We consider that it is important that we have the ability to respond to the changing needs of both our customers and energy markets more generally particularly given that gas is a fuel of choice and given the uncertainty over how energy markets will evolve.

We are currently considering a new price for those customers that live in high-rise apartments, particularly given the large number of apartments being constructed across our Victorian network. There is typically a single commercial meter for each apartment (regardless of the number of residents) that measures usage, which charge is then shared across all residents.

We would need to demonstrate to the AER that the introduction of any new price complied with our obligations, including better promoting the long-term interests of our customers, and that we were no better or worse off as a result of the introduction of this new price. We have specified the conditions for the introduction of a new price in our AA Document.

14.8.6. Cost-Pass-Through Events

We are allowed to adjust our prices during an AA period:

- to reflect changes in our costs that are not within our control; and/or

- where it is unreasonable to accurately determine the impact of costs; and/or
- where the occurrence of the event is uncertain.

We are only allowed to recover these costs where the cost is considered to be material, which is defined by the AER as an event that has an impact of 1.0% of forecast revenue in the year(s) the event occurs. Any Cost-Pass-Through event must first be approved by the AER before being passed through to customers.

The proposed Cost-Pass-Through Events are consistent with those that applied in the current AA period and those recently approved by the AER for our South Australian network, with the exception of the removal of the Mains Replacement Volume Event, which is no longer required and we have maintained the Network User Failure Events and National Energy Customer Framework (NECF) as the National Energy Retail Law does not yet apply in either our Victorian or Albury networks.

The proposed Cost-Pass-Through Events are set out below.

'Regulatory Change Event' means:

A change in a regulatory obligation or requirement that:

a. falls within no other category of Cost-Pass-Through Event; and
b. occurs during the course of an AA period; and
c. affects the manner in which AGN provides Reference Services; and
d. materially increases or materially decreases the costs of providing those services.

'Service Standard Event' means:

A legislative or administrative act or decision that:

a. has the effect of:
   i. substantially varying, during the course of an AA period, the manner in which AGN is required to provide a Reference Service; or
   ii. imposing, removing or varying, during the course of an AA period, minimum service standards applicable to Reference Services; or
   iii. altering, during the course of an AA period, the nature or scope of the Reference Services, provided by AGN; and
b. materially increases or materially decreases the costs to AGN of providing Reference Services.

'Tax Change Event' occurs:

A tax change even occurs if any of the following occurs during the course of an AA period for AGN:

a. a change in a Relevant Tax, in the application or official interpretation of a Relevant Tax, in the rate of a Relevant Tax, or in the way a Relevant Tax is calculated;
b. the removal of a Relevant Tax;
c. the imposition of a Relevant Tax; and

in consequence, the costs to AGN of providing prescribed reference services are materially increased or decreased.

'Terrorism Event' means:

An act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of, or in connection with, any organisation or government), which:

a from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear); and

b increases the costs to AGN of providing the Reference Service.

Note for the avoidance of doubt, in making a determination on a Terrorism Event, the AER will have regard to, amongst other things:

  i whether AGN has insurance against the event;

  ii the level of insurance that an efficient and prudent service provider would obtain in respect of the event; and

  iii whether a declaration has been made by a relevant government authority that an act of terrorism has occurred.

'Network User Failure Event' means:

A Network user Failure Event means the occurrence of an event whereby an existing network user because insolvent or is unable to continue to supply gas to its customers and those customers are transferred to another network user, which materially increases the cost to AGN of providing the Reference Service.

'Insurer Credit Risk Event' means:

An event where:

a an insurer of AGN becomes insolvent; and

b as a result, in respect of an existing, or potential, claim for a risk that was insured by the insolvent insurer, AGN:

  i is subject to a higher or lower claim limit or a higher or lower deductible than would have otherwise applied under the insolvent insurer's policy; or

  ii incurs additional costs associated with self-funding an insurance claim, which would otherwise have been covered by the insolvent insurer.

Note for the avoidance of doubt, in making a determination on an Insurer Credit Risk Event, the AER will have regard to, amongst other things:

a AGN's attempts to mitigate and prevent the event from occurring by reviewing and considering the insurer's track record, size, credit rating and reputation; and

b in the event that a claim would have been made after the insurance provider became insolvent, whether AGN had reasonable opportunity to insure the risk with a different insurer.

'Insurance Cap Event' means:

An event where:

a AGN makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy;

b AGN incurs costs beyond the relevant policy limit; and

c the costs beyond the relevant policy limit increase the costs to AGN of providing the Reference Service.

For this Insurance Cap Event:

d a relevant insurance policy is an insurance policy held during the AA period or a previous period in which access to the pipeline services was regulated; and

e AGN will be deemed to have made a claim on a relevant insurance policy if the claim is made by a related party of AGN in relation to any aspect of the network of AGN's business.

Note for the avoidance of doubt, in making a determination on an Insurance Cap Event, the AER will have regard to, amongst other things:

i the insurance policy for the event;

ii the level of insurance that an efficient and prudent service provider would obtain in respect of the event; and

iii any assessment by the AER of AGN's insurance in approving the access arrangement for the Victorian and Albury gas distribution networks for the relevant period.

'Natural Disaster Event' means:

Any natural disaster including but not limited to fire, flood or earthquake that occurs during the Access Arrangement Period that increases the cost to the Service Provider in providing the Reference Service, provided the fire, flood or other event was not a consequence of the acts or omissions of AGN.

Note for the avoidance of doubt, in making a determination on a Natural Disaster Event, the AER will have regard to, amongst other things:

i whether AGN has insurance against the event; and

ii the level of insurance that an efficient and prudent service provider would obtain in respect of the event.

'National Energy Customer Framework Event' means:

A legislative act or decision that:

a occurs during the AA period;

b has the effect of implementing in Victoria, either in part or in its entirety, the National Energy Customer Framework (NECF); and

c increases the costs to AGN of providing Reference Services.

For the purposes of this pass through event, the NECF means any legislation, regulations or rules, that give effect in Victoria to any or all of the Schedule to the National Energy Retail Law (South Australia) Act 2011, the National Energy Retail Regulations (South Australia) and the National

Energy Retail Rules (South Australia) as amended from time to time, including any amendment, withdrawal or introduction of any associated Victorian legislation, regulations or rules of Victoria or New South Wales.

14.9. Summary

We are proposing to apply the same pricing structures in the next AA period to that currently applying. This approach has been informed by our stakeholder engagement program and reflects a balancing of views provided by our customers and different stakeholder groups. We are also proposing the same price control to apply to our prices and the same process to vary prices over the next AA period.

We have proposed greater flexibility in the extent that prices can be adjusted and to be allowed to introduce new tariffs during the next AA period should this be required. We consider these initiatives are important given gas is a fuel of choice, providing the ability for the business to respond to customers where this is required.

15. Network Access

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15. Network Access

15.1. Introduction

A key part of our relationship with network users is a contractual agreement between the parties that governs the conditions (or terms) of access to our networks, which agreement is commonly referred to as a 'Haulage Agreement'. [144] The terms and conditions of the Haulage Agreement typically reflect the Australian Energy Regulator (AER) approved terms that are set out in our Access Arrangement (AA) Document[145], unless otherwise agreed by the parties.

This chapter discusses the process that we have followed to develop the proposed terms of access to our Victorian and Albury gas distribution networks over the next (2018 to 2022) AA period. We also describe the key changes made to the terms and conditions from those in place during the current (2013 to 2017) AA period. The terms and conditions are set out in our AA Document, which is provided alongside this Final Plan.

15.2. Regulatory Framework

We are required to specify the terms and conditions on which each reference service will be provided in our Final Plan.[146]

15.3. Stakeholder Engagement

Our terms and conditions have been subject to considerable stakeholder consultation through a number of successive AA review processes, and consequently, have been amended over time to take into account feedback we have received from stakeholders and decisions made by the AER. We have continued to apply previous AER decisions as a base for setting the proposed terms to apply to our networks over the next AA period.

We have engaged further with retailers on the proposed terms to apply to our Victorian and Albury networks leading into developing our Final Plan. This engagement has occurred primarily through our Retailer Reference Group (RRG), which comprises representatives from retailers that operate in our Victorian and Albury natural gas distribution markets (see Section 5.3 for a description of our RRG).

We provided our RRG with our proposed terms and conditions prior to finalising our plans. We received feedback from our RRG on these draft terms and on our Draft Plan. Attachment 15.1 sets out in detail our engagement with the RRG leading up to developing this Final Plan, including how we have incorporated their feedback into our proposed terms and conditions. Table 15.1 summaries the key changes to the proposed terms as a result of feedback from our RRG.

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[144] Network users are primarily gas retailers or self-contracting users of our networks.

[145] The AA Document has been submitted by Australian Gas Networks Limited (AGN) to the AER as part of this Final Plan. Further information on the components of our Final Plan is available in Chapter 1.

[146] Consistent with Rule 48(d)(ii) of the NGR, as outlined in Attachment 1.1 to this Final Plan.

Table 15.1: Consideration of RRG Feedback on Terms and Conditions

Retail Reference Group Feedback	Our Response to Feedback on Terms and Conditions
Members of the RRG requested amendments of the following clauses in respect to referencing: • clarify the reference to the National Energy Retail Law (NERL) and National Energy Retail Rules (NERR) (20.2 (b)); and • update the reference to the latest version of the Retail Market Procedures for Victoria (39.2).	We have amended the clauses in response to the RRG feedback as follows: • clarified that the NERL and NERR apply once they are adopted in the relevant jurisdiction (20.2(b)); and • updated the reference to the version dated 27 September 2016 (39.2).
Members of the RRG sought clarification on to the following terms: • 'reasonable test' in authorized conveyance (12.8); • legislative obligations that apply in New South Wales and Victoria authorized conveyance (12.8); • 'should become known' in time limits for adjustments of Distribution Service Charges (22.3); • 'expected to be delivered' in the basis for determination (24.1); and • 'assignment' in assignment of rights and obligations under the agreement (39.3).	We provided further clarification on all aspects sought by the RRG. We also amended the wording of the following clauses to assist the RRG members: • clarify the legislative requirements in clause 12.8; and • defined 'should become known' in new additional clause (22.3 (c)).
Members of the RRG discussed issues with the following clauses: • liable for network charges where there is no shared customer (20.2); • time limits for adjustments of Distribution Service Charges (22.3); • limitation period on claims (29.5); and • removal of insurance requirement by AGN (34.7).	We provided further clarification on all aspects sought by the RRG. The amendments were made to ensure consistency with our recently approved South Australian terms (see Sections 15.4.1 and 15.4.3).
A member believes the failure to provide access (35.5) could be amended or removed as they should not be responsible for AGN's inability to access its own assets.	As noted by the AER in the South Australian Draft Decision there are valid reasons for differences in the terms as the Victorian network is not presently subject to the National Energy Customer Framework (NECF) while the South Australian network is.[147] We have therefore maintained the clause as it provides that AGN will not be liable for any failure to perform the Agreement if the failure is because it could not obtain safe, reasonable, and unhindered access to any premises. The AER in the current Victorian final decision approved clause 35.5(a) as they considered the amendment consistent with the National Gas Objective.[148] We believe that if this clause was removed we would be liable for a failure to provide services where we made reasonable endeavours to gain safe, reasonable and unhindered access to premise but was unable to do so. In effect, this would impose an obligation on AGN to provide services in circumstances where we could only gain access which was unsafe, unreasonable or hindered. As NECF, the NERL and NERR do not apply in Victoria we are proposing to maintain the clause 35.5. We have amended the clause to clarify if the NERL applies in our network the clause will not apply.

Note: In this 'traffic light' table, green shading represents no change from the Draft Plan, orange shading represents a modification of the position outlined in the Draft Plan and red shading represents change from the Draft Plan.

[147] AER, *Attachment 12 – Non-tariff components | Draft decision: Australian Gas Networks Access Arrangement 2016-21*, November 2015, pages 12-10.

[148] AER, *Access arrangement final decision Envestra Ltd 2013-17, Part 2: Attachments*, March 2013, page 276.

Attachment 15.2 provides a marked-up version of our proposed terms and conditions. This clearly sets out all the amendments proposed to our terms and conditions, including those as a result of the feedback from our RRG. We again appreciate the commitment shown by the RRG to actively engage with us to develop our revised terms. We intend to continue to engage with our RRG through the AER review process and over the course of the next AA period.

15.4. Terms and Conditions

15.4.1. Approach

Our terms and conditions set out in our revised AA Document describe our relationship with users, including setting out each party's obligations and liabilities.

As noted in Chapter 2, we have networks in most Australian states and territories. One benefit of national regulation for a business such as ours has been to standardise our terms across all jurisdictions where we have networks. This process of standardisation commenced in 2012 during the last Victorian and Albury AA review process, where significant amendments were made to our terms to align with the South Australian and Queensland terms approved by the AER in 2011.

We are continuing with the process of standardising terms across our networks for the next AA period. We consider this process promotes greater efficiency (through lower transaction costs) across the industry by eliminating, to the extent possible, differences in the terms that apply between jurisdictions (noting that, like AGN, many retailers operate across more than one jurisdiction).

Our proposed terms are substantially the same as those that are currently in place. Some adjustments to the current (AER approved) Victorian and Albury terms are, however, necessary to take into account:

- feedback received from our RRG in the period leading up to developing our Final Plan (see Section 15.3);
- the creation of a common set of terms and conditions applicable to both the Victorian and Albury networks (see Section 15.4.2);
- the stakeholder comments and subsequent AER decision made for our South Australian network, which decision was made in May 2016 (see Section 15.4.3); and
- certain other minor changes, including to reflect the change in our name from Envestra to Australian Gas Networks Limited (AGN) (see Section 15.4.4).

The Victorian and Albury terms were last reviewed by the AER in 2013, at which time they were revised to take account of certain changes requested by our stakeholders. The final terms were then approved by the AER in April 2013 and have applied to our networks over the current AA period. We note that there have been no major areas of dispute or disagreement with users over the terms that currently apply to our networks.

We believe that our approach of using consistent terms across our networks has ongoing advantages of improving efficiency and lowering transaction cost by:

- streamlining the contracting process with retailers and other users across the multiple jurisdictions where we have networks;
- reducing the costs related to entering into a Haulage Agreement and the costs of administering the agreement over the AA period;

- enabling AGN and retailers to develop and utilise consistent internal procedures and processes across multiple jurisdictions;
- streamlining our response to changes in national laws; and
- streamlining regulatory review processes.

We have therefore taken a national approach to contracting on our networks, taking into consideration that jurisdictional differences will always contribute to some variation. We believe that our national approach to developing and implementing the terms across our networks best meets our obligations and is consistent with achieving lowest sustainable costs for our customers.

15.4.2. Consolidation of Victorian and Albury Terms and Conditions

There have been separate AA Documents applying to our Victorian and Albury networks over the current AA period. As described in Section 1.1, in November 2015 we applied to the AER to consolidate the two AA Documents into a single AA Document with a view to reducing administrative costs and improving stakeholder engagement. The AER approved our application to consolidate the Victorian and Albury AAs subject to certain conditions being met.

One of the implications of this decision is that we need to develop a single set of terms for both Victoria and Albury. The changes required to facilitate this have been of a minor nature and relate primarily to either ensuring that a particular term refers to both Victoria and Albury or is otherwise stated in generic terms. The minor nature of these changes to facilitate consolidation reflects that the terms were already consistent as a result of the standardised process referred to earlier.

15.4.3. Harmonisation with South Australian Terms and Conditions

As part of our overarching objective of submitting a plan that delivers for our customers, is underpinned by effective stakeholder engagement and is capable of being accepted by the AER, we have adopted all of the amendments required by the AER in its recent decision for our South Australian network. Table 15.2 sets out the clauses that have been amended in the proposed Victorian and Albury terms as a result of the AER decision for our South Australian network.

Table 15.2: Harmonisation of Victorian and Albury Terms and Conditions with South Australian Terms and Conditions

Clause	Proposed Victorian and Albury Terms and Conditions
3.3	Deleted "*whether or not there is any Shared Customer in respect of that User DP [Delivery Point])*" as required by the AER's Draft Decision for South Australia.[149] The AER received no submissions on this clause as a result of the Draft Decision or AGN's Revised AA Proposal and approved the amendment in the Final Decision.[150]
20.2	Incorporated changes as proposed by AGN in response to the AER's Draft Decision for South Australia.[151] These changes included the deletion of "*subject to sub-clause 22.1*" and "*the Network User is liable for those Distribution Service Charges whether or not the Shared Customer pays those Distribution Service Charges or any other amount to the Network User*".

[149] AER, *Attachment 12 – Non-tariff components | Draft decision: Australian Gas Networks Access Arrangement 2016-21*, November 2015, page 12-31.

[150] AER, *Attachment 12 – Non-tariff components | Final decision: Australian Gas Networks Access Arrangement 2016-21*, May 2016, page 12-11.

[151] AER, *Attachment 12 – Non-tariff components | Draft decision: Australian Gas Networks Access Arrangement 2016-21*, November 2015, page 12-31.

	Addition of: "(*a) the Network User is liable for any component of the Distribution Service Charges which accrues in relation to a User DP whilst there is no Shared Customer in respect of that User DP;* *(b) if there is a Shared Customer in respect of a User DP and the Network User is not permitted to recover Distribution Service Charges from that Shared Customer under the NERL [National Electricity Retail Law] or NERR [National Electricity Retail Rules] (once they are adopted in the relevant jurisdiction), clause 22.1 applies and AGN is not permitted to recover those Distribution Service Charges from the Network User; and* *(c) unless clause 22.1 applies, if there is a Shared Customer in respect of a User DP, the Network User is liable for those Distribution Services Charges which accrue in respect of that User DP, even if the Shared Customer has not paid, or does not pay, those Distribution Service Charges to the Network User.*" The AER accepted the further provision added by AGN in the Final Decision for South Australia.[152]
28.2 (a)	Addition of "*subject to clause 28.4, AGN*" as required by the AER's Draft Decision for South Australia.[153] The AER received no submissions on this clause as a result of the Draft Decision or AGN's revised AA Proposal and approved the amendment in the Final Decision.[154]
28.4	Incorporated the changes made in the South Australian General Terms for the 2016/17 to 2020/21 period as required by the AER's Draft Decision for South Australia.[155] Added New Clause 28.4 Disputed Right of Termination: *"AGN may not give notice of termination under clause 28.2(a) or 28.2(b) for an alleged breach of an obligation by the Network User if the Network User, in good faith, disputes the alleged breach and gives AGN notice of that dispute in accordance with clause 37 within 14 days after the Network User receives notice of the alleged breach. This clause will not apply in any case where it has been determined that the Network User is in breach of an obligation (either by the Independent Expert appointed to resolve the dispute or by a court of law).* *The Network User may not give notice of termination under clause 28.3(a) for an alleged breach of an obligation by AGN if AGN, in good faith, disputes the alleged breach and gives the Network User notice of that dispute in accordance with clause 37 within 14 days after AGN receives notice of the alleged breach. This clause will not apply in any case where it has been determined that AGN is in breach of an obligation (either by the Independent Expert appointed to resolve the dispute or by a court of law)."* The AER received no submissions on this clause as a result of the Draft Decision or AGN's Revised AA Proposal and approved the amendment in the Final Decision.[156]
35.4	Deleted "*use reasonable endeavours*" and addition of "*give reasonable assistance*" as required by the AER's Draft Decision for South Australia.[157] The AER received no submissions on this clause as a result of the Draft Decision or AGN's Revised AA Proposal and approved the amendment in the Final Decision.[158]

[152] AER, *Attachment 12 – Non-tariff components | Final decision: Australian Gas Networks Access Arrangement 2016-21*, May 2016, page 12-7 and pages 12-10 to 12-12.

[153] AER, *Attachment 12 – Non-tariff components | Draft decision: Australian Gas Networks Access Arrangement 2016-21*, November 2015, pages 12-16 to 12-17.

[154] AER, *Attachment 12 – Non-tariff components | Final decision: Australian Gas Networks Access Arrangement 2016-21*, May 2016, page 12-8.

[155] AER, *Attachment 12 – Non-tariff components | Draft decision: Australian Gas Networks Access Arrangement 2016-21*, November 2015, pages 12-16 to 12-17.

[156] AER, *Attachment 12 – Non-tariff components | Final decision: Australian Gas Networks Access Arrangement 2016-21*, May 2016, page 12-8.

[157] AER, *Attachment 12 – Non-tariff components | Draft decision: Australian Gas Networks Access Arrangement 2016-21*, November 2015, pages 12-31 to 12-32.

[158] AER, *Attachment 12 – Non-tariff components | Final decision: Australian Gas Networks Access Arrangement 2016-21*, May 2016, page 12-9.

15.4.4. Other Amendments to the Terms and Conditions

We have also made the following minor changes to the terms:

- throughout the terms Envestra has been replaced with AGN to reflect the change in our name;
- clause 3.4 – insertion of *"... shared"* – this simply corrects an error in the terms and conditions; and
- clause 17.3 (a) –"*any*" changed to "*those*" to improve language.

15.5. Summary of the AA Document

As noted earlier, the AA Document sets out the proposed prices and terms and conditions under which we offer access to our networks. The format of the proposed AA Document remains largely unchanged from the current period AA Document. Attachment 15.2 provides a summary of the changes to the proposed AA Document. To aid in the understanding of the AA Document and the proposed terms and conditions we have developed a summary of their contents in Table 15.3.

Table 15.3: Structure of the AA Document

Section	Overview
Introduction	Purpose, commencement date, and contact details for the AA.
Services	A description of the services AGN will provide over the next AA period.
Reference Tariffs	An overview of our reference tariffs over the next AA period.
Reference Tariff Policy – General	A description of how the reference tariffs are determined, how Network Users are assigned tariffs and the basis for their annual adjustment through the Reference Tariff Control Formulae and the Cost-Pass-Through Event Adjustments over the next AA period. As part of our standardisation we have adopted a number of the amendments required by the AER in its recent (2016) decision for our South Australian network in respect of the Cost-Pass-Through Events (see Section 14.8.6).
Reference Tariff Policy – Incentive Mechanisms	A description of how the incentive arrangements (operating expenditure, capital expenditure sharing scheme and network innovation scheme) will apply over the next AA period (see Section 11.6).
Terms and Conditions	An overview of our proposed terms and condition and the conditions that a Prospective Network User must satisfy prior to entering into an agreement.
Capacity Trading	A description of the capacity trading and queuing requirements for our networks over the next AA period. This section also details the processes for changes to Delivery Points.
Network Extension and Expansions	A description of the regulatory treatment of network extensions and expansion over the next AA period.
Speculative Capital Expenditure	A description of how non-conforming capital expenditure will be treated by AGN in the next AA period. This is a new clause and is included to detail the existing treatment under the NGR.
Review of the Access Arrangement	The date the next revised AA will be provided to the AER and the commencement date of the next AA Document.
Glossary	A description of the meaning of words or phrases for the AA Document and Final Plan.
Annexure A – Our Networks	A description of the geographical area of our Victorian and Albury networks.
Annexure B – Tariff Schedule 2018	A description of the proposed reference tariffs for 2018.
Annexure C – Calculation of Charges for Delivery Points	A description of how the Distribution Service Charges are calculated over the next AA period.
Annexure D – Reference Control Formulae	Details the proposed Reference Tariff Control Formulae over the next AA period. The four Reference Tariff Control Formulae have been amended as detailed in Attachment 15.2.
Annexure E – Specific Terms and Conditions	This allows for the details pertaining to the specific circumstances of the parties entering into an agreement other than the General Terms and Conditions.
Annexure F – General Terms and Conditions	Sets out the proposed terms that are to apply, as a minimum, to the provision of each Haulage and Ancillary Reference Services for our networks.
Annexure G – Asset Performance Index	Sets out the proposed asset performance index as a result of the introduction of the capital expenditure sharing scheme in Incentive Mechanisms.

15.5.1. Capacity Trading Requirements

Capacity trading allows a user to transfer by the way of a subcontract all or any of the users' contracted capacity to another user. It is a requirement of the National Gas Rules that the AA sets out the capacity trading requirements.[159] We have not proposed any changes to the capacity trading section of the AA Document.

15.5.2. Network Extensions Requirements

A significant extension is one that does not routinely occur within the business and is not factored into the allowed capital and operating expenditure. These provisions require AGN to apply to the AER to determine whether any proposed significant extension is to be taken to form part of the covered network. We have proposed a number of changes to the network extensions section of the AA Document to align with the other Victorian gas distributors.

15.5.3. Speculative Capital Expenditure

This is a new clause added to the AA and explains how we may recover the cost of non-conforming capital expenditure if it becomes conforming.[160] The wording of this clause is consistent with that contained in the Jemena Gas Networks Access Arrangement for its New South Wales gas distribution network, which was approved by the AER in 2015.

15.6. Summary

The terms and conditions are a key part of our relationship with users. The proposed terms are the basis that users gain access to our networks and generally form the basis for the contractual agreement entered into between the parties. Our proposed terms have gone through considerable consultation with stakeholders over the past six years, including:

- in 2011 as part of the South Australian and Queensland AA review process;
- in 2012 as part of the Victorian and Albury AA review process, which is when we first commenced the process of standardising terms across all of our networks;
- in 2016 as part of the recent South Australian review process; and
- in 2016 with our RRG as part of the process of developing the revised terms to apply to our Victorian and Albury networks from 1 January 2018.

We consider that this process of standardising our terms across our networks is consistent with achieving lowest sustainable costs for our customers.

[159] Consistent with Rule 48(f) of the NGR, as outlined in Attachment 1.1 to this Final Plan.

[160] Conforming capex is capex that satisfies the requirements of Rule 79 of the NGR, as outlined in Attachment 1.1 to this Final Plan.

Acronyms and Abbreviations

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List of Acronyms and Abbreviations

Term	Meaning
AA	Access Arrangement
AAI	Access Arrangement Information (also known as Final Plan)
AA Proposal	AGN's submission to the AER, consisting of a revised AA proposal, AAI and other supporting documents
ACT	Australian Competition Tribunal
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGN	Australian Gas Networks Limited
AGN Qld	Australian Gas Networks Limited Queensland
AGN SA	Australian Gas Networks Limited South Australia
AGN Vic	Australian Gas Networks Limited Victoria
Ai Group	Australian Industry Group
AMP	Asset Management Plan
APA	APA Asset Management/APA Group
ARORO	Allowed Rate of Return Objective
ARS	Ancillary Reference Services
ASX	Australian Securities Exchange
AS 4645	Australian Standard 4645
ATO	Australian Tax Office
BEE	Benchmark Efficient Entity
CAM	Cost Allocation Model
CAPM	Capital Asset Pricing Model
Capex	Capital expenditure
CBD	Central Business District
CCP	Consumer Challenge Panel
CEO	Chief Executive Officer
CESS	Capital Expenditure Sharing Scheme
CGS	Commonwealth Government Securities

CI	Cast iron
COSBOA	Council of Small Business Australia
COTA	Council of the Ageing
CPI	Consumer Price Index
CTM	Custody Transfer Metering
current AA period	The current 1 January 2013 to 31 December 2017 Access Arrangement Period
CUAC	Consumer Utilities Action Centre
DBYD	Dial Before You Dig
DGM	Dividend Growth Model
DMIS	Demand Management Incentive Scheme
DMSIP	Distribution Mains and Services Integrity Plan
DRP	Debt Risk Premium
EAM	Enterprise Asset Management
EBSS	Efficiency Benefit Sharing Scheme
ECA	Energy Consumers Australia
EDD312	Effective Degree Day
ENA	Energy Networks Association
ESV	Energy Safe Victoria
EUAA	Energy Users Association of Australia
EWOV	Energy & Water Ombudsman Victoria
FFO	Funds from Operations
Final Plan	Plan, also known as Access Arrangement Information (AAI)
FSC	Farrier Swier Consulting
GFC	Global Financial Crisis
GIS	Geospatial Information System
GJ	Gigajoule
GSL	Guaranteed Service Level
HDICS	High Density Inner City Suburbs
HDPE	High Density Polyethylene
HIA	Housing Industry Association
HRS	Haulage Reference Services

IT	Information Technology
JGN	Jemena Gas Networks
KPIs	Key Performance Indicators
LDS	Low Density Suburbs
LTIFR	Lost Time Injury Frequency Rate
MHQ	Maximum Hourly Quantity
MRP	Market Risk Premium
MTFP	Multilateral Total Factor Productivity
NECF	National Energy Customer Framework
NERL	National Energy Retail Law
NERR	National Energy Retail Rules
next AA period	The next 1 January 2018 to 31 December 2022 Access Arrangement Period
NGL	National Gas Law
NGO	National Gas Objective
NIS	Network Innovation Scheme
NMF	Network Management Fee
NGR	National Gas Rules
NSP	Network Service Providers
OE	Origin Energy
Ofgem	Office of Gas and Electricity Markets
OMA	Operating and Management Agreement
Opex	Operating expenditure
PMCs	Periodical Meter Change
PIAC	Public Interest Advocacy Centre
previous AA period	The previous 1 January 2008 to 31 December 2012
PTRM	Post-tax Revenue Model
PVC	Polyvinyl Chloride
RAB	Regulatory Asset Base
RBA	Reserve Bank of Australia
RIN	Regulatory Information Notice
RoLR	Retailer of Last Resort

RRG	Retailer Reference Group
SAIDI	System Average Interruption Duration Index
SCADA	Supervisory Control and Data Acquisition
SL CAPM	Sharpe-Lintner Capital Asset Pricing Model
SoMP	Statement of Monetary Policy
STPIS	Service Target Performance Incentive Scheme
subsequent AA period	The 1 January 2023 to 31 December 2027 Access Arrangement Period
TAB	Tax Asset Base
Tariff C	Tariff paid by commercial (also known as Non-Residential) customers
Tariff D	Tariff paid by industrial (also known as Demand) customers
Tariff R	Tariff paid by residential customers
TFP	Total Factor Productivity
TJ	Terajoule
the networks	The Victorian and Albury natural gas distribution networks
the Vision	Australian Gas Networks Limited's Vision Statement
TSD	Thermal Safety Devices
UPS	Unprotected Steel
VARG	Victoria/Albury Reference Group
VEF	Victorian Energy Forum
WACC	Weighted Average Cost of Capital (also known as rate of return)
WAPC	Weighted Average Price Cap

List of Attachments

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List of Attachments

1.1 Relevant Regulatory Framework – December 2016

1.2 Australian Gas Networks Draft Plan – 5 July 2016

1.3 CEO Statutory Declaration – 21 December 2016

1.4 Regulatory Information Notice Index – December 2016

1.5 Victoria Regulatory Information Notice – December 2016

1.6 Albury Regulatory Information Notice – December 2016

1.7 Victoria Roll Forward Model – December 2016

1.8 Albury Roll Forward Model – December 2016

1.9 Victoria and Albury Post Tax Revenue Model – December 2016

1.10 KPMG – Support for Population of Regulatory Models (Victoria and Albury) – 16 December 2016

1.11 Submission Document Map – 21 December 2016

1.12 Confidentiality Claims – 21 December 2016

2.1 Australian Gas Networks 2015 Annual Review – 24 June 2016

3.1 Economic Insights – The Productivity Performance of Victorian Gas Distribution Businesses – 15 June 2016

3.2 Economic Insights – Benchmarking Vic Gas Distribution Business Operating and Capital Costs Using Partial Performance Indicators – 15 June 2016

5.1 Log of Documents on the Australian Gas Networks Stakeholder Website – 21 December 2016

5.2 Australian Gas Networks Victoria and Albury Stakeholder Engagement Scoping Paper – January 2016

5.3 Australian Gas Networks Overarching Stakeholder Engagement Strategy – March 2016

5.4 Australian Gas Networks Victoria and Albury Stakeholder Engagement Strategy – March 2016

5.5 Customer Workshop Fact Sheets – March 2016

5.6 Customer Workshop Presentation – March 2016

5.7 Deloitte – Australian Gas Networks Customer Insights Report – May 2016

5.8 Written Stakeholder Submissions on the Australian Gas Networks Draft Plan – August 2016

5.9 Australian Gas Networks Draft Plan Stakeholder Workshop Presentations – August 2016

5.10 Deloitte – Australian Gas Networks Stakeholder and Customer Feedback Report – December 2016

5.11 Australian Gas Networks Draft Plan Customer Workshop Presentation – October 2016

5.12 Australian Gas Networks Stakeholder Engagement Program Feedback Forms – December 2016

7.1 Axiom Economics – Consistency of the Victorian Gas Distribution Businesses' Joint Marketing Campaign with Rule 91 of the NGR – December 2016

7.2 BIS Shrapnel – Utilities Sector and Construction Industry Wage Forecasts to 2022 – Australia and Victoria – October 2016

7.3 ACIL Allen – Opex Partial Productivity Analysis – December 2016

7.4 Operating Expenditure Forecasting Model – December 2016

8.1 Asset Management Plan – December 2016

8.2 Distribution Mains and Services Integrity Plan – December 2016

8.3 Meter Replacement Plan – December 2016

8.4 Unit Rates Forecast – December 2016

8.5 Information Technology Investment Plan – December 2016

8.6 Business Cases – December 2016

8.7 KPMG – IT Expenditure Benchmarking, Australian Gas Networks Limited Victoria and Albury – December 2016

8.8 Capital Expenditure Forecasting Model – December 2016

8.9 ESV – Australian Gas Networks Distribution Mains and Services Integrity Plan, September 2016 – 20 December 2016

8.10 AEMO – Letter Regarding Sale Minimum Connection Pressure – 21 November 2016

9.1 Incenta – Low Pressure Mains and Services Depreciation – December 2016

9.2 Inflation – December 2016

9.3 PWC – Breakeven Inflation Liquidity Support – December 2016

9.4 CEG – Best Estimate of Expected Inflation – September 2016

9.5 CEG – Inflation Compensation – Addendum to September Report – 14 December 2016

10.1 Financing Costs – December 2016

10.2 CEG – Replication and Extension of Henry's Beta Analysis – September 2016

10.3 Frontier Economics – The Market Risk Premium – September 2016

10.4 CEG – The AER's Current Interpretation of the ARORO – September 2016

10.5 Frontier Economics – An Updated Dividend Drop-off Estimate of Theta – September 2016

10.6 Frontier Economics – Issues in the Estimation of Gamma – September 2016

10.7 Frontier Economics – Perspectives for the Estimation of Gamma – December 2016

10.8 Averaging Periods – Confidential

11.1 Farrier Swier Consulting – Issues Paper, Incentive Mechanisms for the Victorian Gas Distribution Businesses, 2018 to 2022 Gas Access Arrangement Review – 10 June 2016

11.2 Farrier Swier Consulting – Presentation, Overview of Incentive Frameworks – 11 July 2016

11.3 Farrier Swier Consulting – Findings Report, Victorian Gas Distribution Businesses Consultation on Incentive Mechanisms – 23 September 2016

11.4 Written Stakeholder Submissions on Incentives Issues Paper and Workshop – July/August 2016

11.5 Overview of Incentive Frameworks Workshop Feedback Forms – July 2016

11.6 Farrier Swier Consulting – Gas Services Incentives in Victoria and Albury – 15 December 2016

13.1 Core Energy Group – Gas Demand Forecasts – December 2016

13.2 Core Energy Group – Gas Demand Forecast Model – Victoria – December 2016 – Confidential

13.3 Core Energy Group – Gas Demand Forecast Model – Albury – December 2016 – Confidential

13.4 Core Energy Group – Weather Normalisation Model – Victoria – December 2016 – Confidential

13.5 Core Energy Group – Weather Normalisation Model – Albury – December 2016 – Confidential

14.1 Cost Allocation Model – December 2016

14.2 Network Pricing, Formulae and Efficiency – December 2016

15.1 Engagement with the Australian Gas Networks Retailer Reference Group on the Proposed Terms and Conditions – December 2016

15.2 Summary of Changes to the Access Arrangement Document Including the Terms and Conditions – December 2016

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