Australian Gas Networks

Five year plan for our South Australian network

July 2021 - June 2026

Final Plan
July 2020

Contents

We are Australian Gas Networks. We deliver gas safely and reliably to more than 460,000 South Australian homes and businesses every year.

Our vision is to be the leading gas infrastructure business in Australia by delivering for customers, being a good employer and being sustainably cost efficient.

We serve residential, commercial and industrial customers in Adelaide (from Two Wells to Aldinga) and regional centres in the upper north, Barossa, Riverland and South East of the state. We have a strong track record of service to customers in South Australia, dating back more than 150 years.

We understand that affordability, reliability and sustainability of energy services are important to South Australians, both now and in the future.

With this in mind, our Final Plan has been developed by listening and responding to the interests of our customers.

We are pleased to present our Final Plan for the South Australian gas distribution network for the 2021/22 to 2025/26 Access Arrangement (AA) period.

This document sets out our plan for the next AA period and our commitment to deliver for customers by providing safe, affordable and reliable services to our customers.

Australian Gas Networks (AGN) is part of Australian Gas Infrastructure Group (AGIG), one of Australia's largest energy infrastructure businesses. Our South Australian distribution network plays a crucial role in the economy and community more broadly in serving the energy needs of households, small businesses and industry in Adelaide and the regions.

We want customers to be at the centre of our plans. This will ensure that we deliver for our customers now and into the future. Our plan outlines what we have delivered for our customers in the current AA period (2016/17 to 2020/21) and what we will deliver in the next AA period (2021/22 to 2025/26).

In the current AA period we have delivered for our customers, including:

- our highest ever customer satisfaction rating: 8.5 out of 10 so far in 2020;
- strong public safety performance: responding to 99% of publicly reported leaks within 2 hours;
- significant cost reductions from the AGIG merger;
- very high reliability: one hour off supply every 40 years on average; and
- 1,000 km of mains replaced since 2016: future proofing our network.

Our Final Plan outlines how we will continue to deliver on these expectations. It is informed by an extensive engagement program with our customers and stakeholders. We worked closely with more than 120 customers, holding 22 workshops over 3 phases during the development of this Final Plan including residential and business, metropolitan and regional, and culturally and linguistically diverse customers and communities. The engagement program activities have included a series of workshops, ongoing engagement with our stakeholder reference groups, and co-design workshops.

We also held co-design workshops on how to better support vulnerable customers, which have led to our proposed Vulnerable Customer Assistance Program (VCAP).

More than 90% of customers and stakeholders told us our program was inclusive, transparent, well run and of a high standard. 98% of customers felt they had an opportunity to have their say.

Price and affordability remain our customers' top priorities – a concern made all the more important given the economic impact of the COVID-19 pandemic on many customers. The pandemic has had a significant economic and social impact for many South Australians and therefore it was more important than ever, that our Final Plan deliver network price relief.

Our Final Plan delivers an upfront price cut of 7% (after inflation) from 1 July 2021 and follows on from a 21% (after inflation) cut to our prices five years earlier. Our prices will grow in real terms within the next period to match our asset base, but these cuts mean that customers will be paying more than 20% less in 2025/26 (before inflation) than what customers paid in 2015/16.

In the engagement program 96% of customers supported or strongly supported our Draft Plan, including our proposed price cut.

Delivering for customers is a key part of our vision, and by locking in cost savings resulting from our merger and maintaining our expenditure at current levels and delivering a price reduction, customers can have one less thing to worry about.

Our Final Plan also delivers on a range of initiatives supported by our customers and stakeholders. These include:

- investment to improve our customer communications through a range of digital channels;
- investing in a vulnerable customer assistance program; and
- proposing a network innovation scheme.

Customers also overwhelmingly support action to respond to climate change with 87% suggesting that finding ways to lower emissions was very or extremely important to them.

Given this level of concern, our Final Plan proposes to offset up to 20% of our unaccounted for gas (UAFG) with renewable gas, which 84% of customers supported.

This proposal builds on our existing activities to decarbonise the gas distribution network – including at Hydrogen Park South Australia where we will begin delivering a renewable hydrogen/natural gas blend to 700 homes in Mitchell Park later in 2020.

These and other activities create options for the gas network as the energy sector is transformed – helping to ensure that we can deliver safe, reliable and affordable energy with zero emissions in the future.

Meanwhile, our Final Plan delivers on other customer and stakeholder priorities. We will maintain our safety and reliability record. We will replace around 860 km of mains, which will see the removal of all of our old cast iron mains, a significant safety milestone for our customers and our business.

We may also shortly begin extending the network to Mount Barker. Customers in Mount Barker would then be able to share in the benefits of natural gas and our pathway to zero emissions gas.

In developing the Final Plan our objectives are to develop a plan that delivers for current and future customers, is underpinned by effective stakeholder engagement, and is capable of being accepted by our customers and stakeholders.

Our Final Plan reflects on the feedback received from customers up to and after the publication of our Draft Plan in February 2020. This helps to ensure that customers remain at the centre of our planning, and is a key part of our no surprises approach.

The Final Plan will now form the basis of a review by the Australian Energy Regulator (AER), which will include a stakeholder consultation process. I strongly encourage our customers and stakeholders to participate in the AER's process.

Ben Wilson

Chief Executive Officer, Australian Gas Infrastructure Group

Final Plan

2021/22 – 2025/26

Customers are at the centre of our planning in South Australia

Our customers and stakeholders value:

- Maintaining a high level of community safety and reliability
- Sustaining our strong track record of customer service
- Keeping costs low, while still investing for the future

Lower prices

7% price cut from 1 July 2021 (after inflation)

Our plan from July 2021

Delivering for customers

39,000 new connections

>8.2 customer satisfaction

public leak reports within **2 hours**

>95% and 100% compliance with Leak Management Plans

A good employer

Top decile employee engagement

>99% mandatory training compliance

Target Zero Harm across our operations

Sustainably cost efficient

Stable operating and capital expenditure

Initial investments to secure the long-term future of the SA distribution network

860 km of mains replacement

completing the replacement of our highest risk mains

New proposals shaped by our customers

During our engagement program customers shaped three new proposals which they felt were in their long-term interests. We also support the delivery of these initiatives which will improve service quality and accessibility and create future options for the network as we transition to zero emissions.

Renewable Unaccounted for Gas (UAFG)

UAFG is the gas lost in our network that may arise as a result of leaks, metering inaccuracies and/or gas theft. In addition to being a key part of our operating expenditure it is also the largest source of direct greenhouse gas emissions from operating the South Australian distribution network.

Addressing UAFG emissions can serve as a stepping stone to developing low and zero carbon options for the wider network, helping to create options for the future of the network.

During our engagement program 87% of customers considered it very important or extremely important that we consider ways to lower carbon emissions. In response we worked with customers to shape a proposal to offset a portion of our UAFG with renewable gases.

When we explored potential new initiatives with our customers at our customer workshops, this was the highest ranked option. 84% of customers supported or strongly supported investment in renewable gas for UAFG at a cost of between $1.50 – $5.50 on the average annual bill.

"We as customers need to be accountable for emissions"

We have therefore incorporated this proposal in our Final Plan.

See Section 7.4.4.

Vulnerable Customer Assistance Program (VCAP)

Traditionally, the provision of assistance to vulnerable customers has been the domain of retailers, not-for-profit organisations and governments. Through our stakeholder engagement process, the development of the Energy Charter (which AGIG is a signatory to), and the COVID-19 pandemic, it has become clear that we have a larger role to play in supporting our vulnerable customers.

This is reflected in the feedback provided through our customer workshops, with 77% of our customers actively supporting a vulnerable customer assistance program at a cost of between $1 - $2 p.a. on their bill. A further 19% of our customers were slightly to moderately supportive of such a program.

We prioritised the elements of the VCAP during a series of three co-design workshops with stakeholders from the social and community services sector.

Following the co-design workshops we have included the VCAP in our Final Plan which proposes to:

- establish a dedicated vulnerable customer service role within AGN to work directly with vulnerable customers to resolve complaints, liaise with community organisations, develop referral programs and contribute to the setting of an appropriate policy framework;
- develop a priority services register using an upgraded Customer Relationship Management (CRM) system; and
- provide for our vulnerable customers gas appliance safety checks and emergency repairs and rebates to help access more efficient appliances.

The program will improve the customer experience for our vulnerable customers and will reduce the financial barriers that some vulnerable customers may face in terms of utilising gas more efficiently and/or ensuring their appliances are operating in a safe and reliable manner.

"This is very important for older Australians, and people who are struggling financially"

See Section 7.4.2.

Innovation allowance

The current regulatory framework makes it difficult to invest in innovation because of a lag between the investment and the benefits it can deliver.

A network innovation allowance, as adopted for gas networks in the UK for example, would provide a clear framework (including rules and requirements) for funding of innovative projects.

During our customer and stakeholder engagement program almost 8 in 10 customers were either supportive or strongly supportive of investment in innovation (through an Innovation Allowance). Based on this customer support, and our own view on the importance of innovation, we are proposing to introduce a network innovation allowance of $2.5-5 million in the next AA period.

We intend to continue to engage with our customers and stakeholders, the AER and the wider industry over the coming months to define the scope and form of this scheme in time for the AER's Draft Decision in November 2020.

"Australia is a clever country, so with this fund there would be an incentive to put theory into practice"

See Section 11.5.

1 Plan Highlights

IN THIS CHAPTER:

We have a strong track record of safety, reliability and customer service in the current period.

An upfront price cut for the next AA period of 7% (after inflation) builds on the price cut of 21% delivered at the beginning of the current AA period.

Our Final Plan outlines the activities and investments we propose to undertake for the 2021/22 to 2025/26 period and the resulting price change for our customers.

Our intention is that customers are at the centre of our plans. Our Final Plan has been informed by an extensive customer and stakeholder engagement program involving more than 120 customers.

This section highlights how we have developed our Final Plan, our achievements for the current period and the key elements of our proposal for the next period.

1.1 Developing this plan

We engaged extensively with a diverse range of customers and stakeholders to understand their values, needs and expectations for the services we provide.

Across a series of 22 dedicated customer workshops spanning five locations and a total of 319 participants, we listened to customers to inform our Final Plan. We also published a Draft Plan in February 2020, providing an opportunity for customers and stakeholders to consider and respond to detailed proposals. Our customer and stakeholder engagement has been fundamental in informing this Final Plan.

More than 90% of customers and stakeholders told us our program was inclusive, transparent, well run and of a high standard. 98% of customers felt they had an opportunity to have their say. 96% of customers support our plans including our proposed price cut.

The plan will now be considered by the AER including its own consultation process.

1.2 Our track record

Over the current period we have met the high expectations of our customers and stakeholders, including meeting key safety, reliability and customer service standards set for our business.

Our vision is to continue to deliver quality services that our customers value, to be recognised as a good employer and to remain sustainably cost efficient. During the current period we have delivered on that vision, and we aim to continue our progress during the next AA period.

Our key achievements during the current AA period so far are summarised below.

Delivering for customers

- A 21% price cut (after inflation) to our customers on 1 July 2016.
- Our customer satisfaction scores have continued to increase, to 8.5 out of 10 so far in 2020, our highest score ever.
- Excellent public safety performance: responding to 99% of publicly reported leaks within 2 hours.
- Very high reliability: one hour off supply every 40 years on average per customer.
- We will have connected over 30,000 customers this period, bringing our total customer base to over 460,000.

- 93% of Emergency calls have been answered within 30 seconds, with an average time to answer calls of 8.4 seconds.

A good employer

- The Total Recordable Injury Frequency Rate (TRIFR) has averaged 10.6 across AGN in 2018 and 2019.
- Employee engagement scores have remained within or near the top decile for our industry, averaging 76%.
- 99% of compliance training has been completed within the required timeframes.

Sustainably cost efficient

- We will have replaced over 1,000 km of mains in the current period, consistent with the undertaking we gave to our customers and stakeholders at the beginning of the period.
- The Adelaide CBD mains replacement is on track for completion, which will see all mains classified as high risk in the Adelaide CBD replaced by the end of the current period.
- By the end of the current AA period we expect to complete the gas pipeline to Mount Barker, one of South Australia's fastest growing regions.
- Opex is expected to be 17% below our allowance, the benefits of which are passed onto our customers in our proposals for the next period. These savings reflect one-off benefits from our merger with AGIG in 2017.

1.3 What we will deliver

Our Final Plan for the next period builds on our strong performance over the current period. The activities and expenditure we propose to undertake in the next five years are summarised below.

Delivering for customers

- We will connect around 39,000 new residential, business and industrial customers.
- We will replace around 860 km of mains, completing the replacement of the highest risk mains in our network.
- We will take the first steps to secure the long-term future of the South Australian distribution network such as:
  - offsetting 20% of our unaccounted for gas (UAFG) with renewable gas (biomethane), which is a net carbon neutral gas;
  - investing in a new vulnerable customer assistance program (VCAP) which will establish a dedicated vulnerable customer role within AGN and develop a priority services register for vulnerable customers; and
  - proposing a network innovation scheme, delivering the innovation required for the long-term future of the network and to meet the long-term interests of our customers.

We will invest $31 million on projects and programs to continue to meet the service expectations of our customers, including meter replacement, IT and digital services.

A good employer

- We will continue to target zero harm throughout our operations.
- We will maintain top decile employee engagement scores to ensure we remain customer and safety focussed.

Sustainably cost efficient

- Our combined operating and capital expenditure will be maintained at current levels, while our network continues to grow in size and customer numbers.
- We will make investments that create options for the SA distribution network to play a role as the state works towards net-zero emissions by 2050.

Overall, our Final Plan delivers an upfront price cut of 7% (after inflation), followed by increases of 1.2% per year (plus inflation) thereafter reflecting the real growth in our regulated asset base. This builds on our price cut of 21% delivered at the beginning of the current period, and means that by 2025/26 customers will be paying around 20% less (before inflation) than what customers paid in 2015/16.

The transition underway in the energy sector is not without risks for gas networks – risks over and above those being faced by electricity networks.

We are confident about the future of the network. Our South Australian network represents a significant investment that can deliver safe, reliable and affordable energy with zero emissions in the future.

When these risks are taken into account, the prices we propose represent exceptional value for our customers and for the South Australian economy.

Purpose of this plan

Regulatory framework

The National Gas Law (NGL) and National Gas Rules (NGR) provide the framework for the regulation of certain gas pipelines in Australia. This framework is enacted in South Australia through the National Gas (South Australia) Act 2008.

In South Australia, the Australian Energy Regulator (AER) is responsible for regulation under the NGL and NGR framework, including the approval of AA proposals and revisions every five years.

The AA contains our proposed reference services and the terms and conditions under which a customer can gain access to the South Australian distribution network.

This includes:

- the services offered on the network;
- the price paid for those services; and
- the non-price terms under which access will be provided.

The terms and conditions approved through an AA set a framework around which gas distribution network operators like AGN and shippers (energy retailers and large businesses) can negotiate access. These terms and conditions then form the basis of the network component of residential and small business customers' bills.

More information on the regulatory framework is included in Attachment 1.6, including a table cross-referencing relevant provisions from the NGR with the relevant sections of our Final Plan, attachments and Access Arrangement document.

Our review objectives

Our aim is to develop a plan that:

- delivers for current and future customers;
- is underpinned by effective stakeholder engagement; and
- is capable of being accepted by our customers and stakeholders.

This Final Plan sets out our plans for the South Australian gas distribution network for the five-year period commencing 1 July 2021. The Final Plan presents the proposed revisions for the South Australia AA which we are required to submit to the AER by 1 July 2020. This is in accordance with the review submission date in the current South Australian AA in respect of the current five-year period ending on 30 June 2021.

The Final Plan follows acceptance of our Reference Service Proposal and publication of our Draft Plan in February 2020, the preparation of which was informed by a robust stakeholder engagement program. The Draft Plan provided an opportunity to engage with our customers and stakeholders prior to developing this Final Plan, which forms our submission to the AER.

As part of our "no surprises" approach to running our business, our stakeholder engagement program has enabled our customers and other stakeholders to inform and shape the Final Plan. This program was well received by our customers and stakeholders.

More details on the stakeholder engagement program and our responses to the feedback received are included in Chapter 5 (Stakeholder Engagement).

This Final Plan provides the activities and expenditure we propose to undertake during the next AA period, incorporating feedback received on the Draft Plan and through stakeholder engagement. We also provide an indication of the likely change in prices for our customers (noting prices will be updated to reflect the most recent information available before 1 July 2021).

How to read this plan

The first six chapters of this document provide an overview of our plans, our business, our stakeholders, our pipeline services and the process we have undertaken to develop a plan that delivers for our customers. We also provide an overview of the future of gas and the gas distribution network in South Australia.

Each subsequent chapter then steps through the "regulatory building blocks" that form our required revenue and prices. These are:

Chapter 7 - Operating expenditure (opex)
The expenditure we require to run our business day-to-day.

Chapter 8 - Capital expenditure (capex)
The investment in our assets required to deliver services to our customers.

Chapter 9 - Capital base
The total value of our investment in the South Australian network, which we have not yet recovered from customers and therefore need to finance.

Chapter 10 - Financing costs
The cost of financing our capital base and meeting our tax obligations.

Chapter 11 - Incentive arrangements
Additional rewards and penalties that we consider should be applied to strengthen our efficiency and performance, while promoting the long-term interests of our customers.

Chapter 12 - Demand forecasts
The number of new connections and total amount of energy we forecast to deliver to customers.

Chapter 13 and 14 - Revenue and pricing and Network access
In the last two chapters, we outline how we have calculated the total revenue required, the resulting prices for our services (Chapter 13), and the terms and conditions for access (Chapter 14).

All numbers quoted throughout this Final Plan are dollars of June 2021, unless otherwise labelled.

Next steps

Shortly after receipt of this Final Plan, the AER will commence a formal engagement process. Customers and other stakeholders are encouraged to participate in this process. We will also continue to engage with our customers and stakeholders over this period.

We also welcome any feedback, which can be provided:

- online at gasmatters.agig.com.au
- by mail
- in person

Contact information is provided on the back cover of this document.

2 Our business

IN THIS CHAPTER:

We are one of Australia's largest gas infrastructure businesses.

Our vision and values drive what we do and the way we do it.

We deliver gas safely and reliably to around 460,000 South Australian homes and businesses every year.

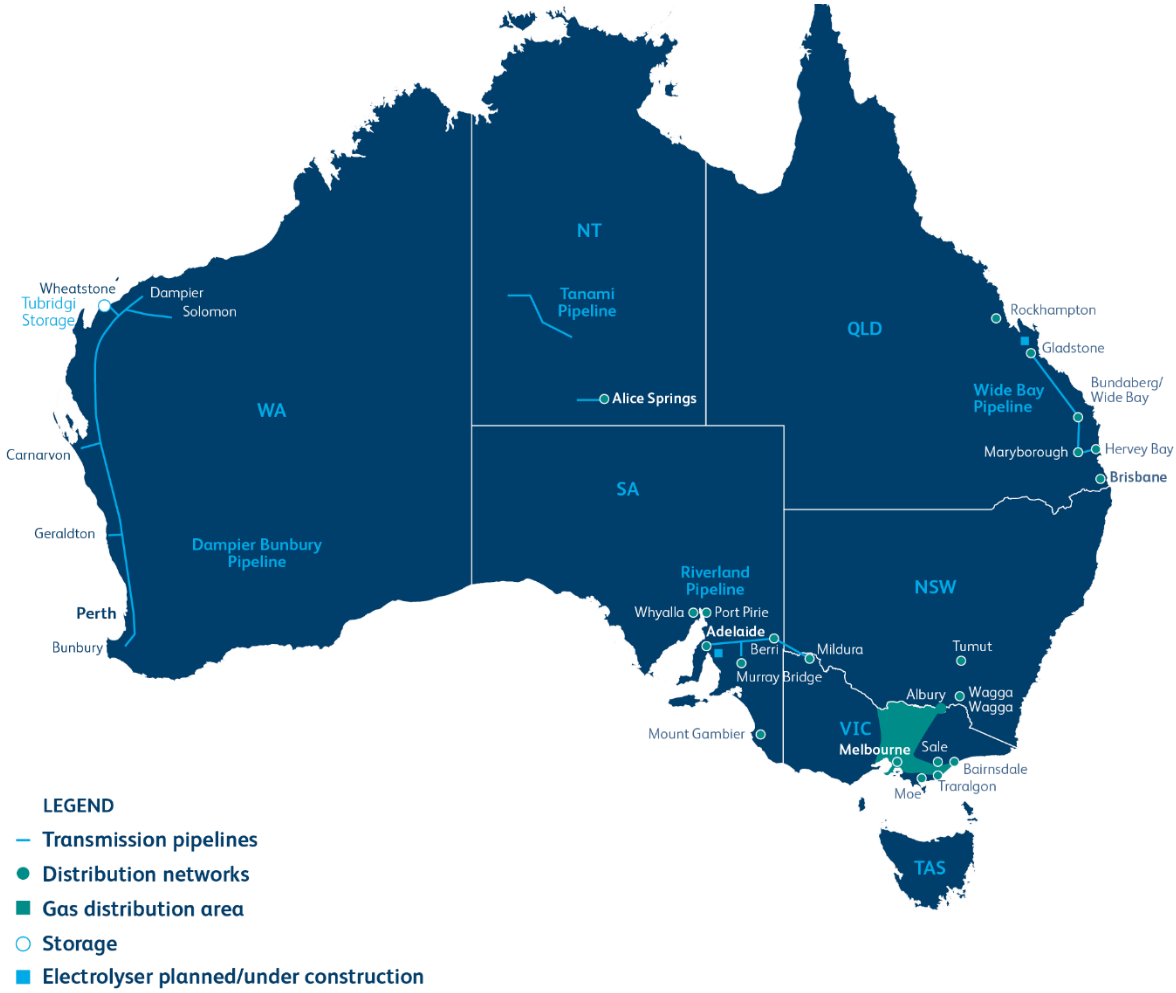
Australian Gas Networks (AGN) is part of the Australian Gas Infrastructure Group (AGIG), one of the largest gas infrastructure businesses in Australia.

2.1 About AGIG

AGIG serves over two million customers across every mainland state and the Northern Territory. Our assets include around 34,600km of distribution networks, over 4,400km of transmission pipelines and 57 petajoules of storage capacity.

In 2017 AGN, Multinet Gas Networks (MGN) and Dampier to Bunbury (DBP) came together to create AGIG. The scale and expertise of AGIG is delivering enhanced benefits to AGN's customers in South Australia in the current AA period as outlined in Chapter 3.

Figure 2.1: AGIG assets



2.2 Our vision

Our vision is to be the leading gas infrastructure business in Australia. Our definition of leading is to achieve top quartile performance across all our key targets compared to other Australian gas infrastructure businesses.

To help achieve this vision, we have set ourselves the following objectives, which we believe are consistent with being the leading gas infrastructure business in Australia.

- *Delivering for customers* – this means ensuring public safety and the provision of high levels of reliability and customer service.
- *A good employer* – this means ensuring the health and safety of our employees and contractors, and having an engaged and skilled workforce.
- *Sustainably cost efficient* – this means getting the work done within benchmark levels by continually looking for ways to improve cost of service, pursuing growth, and ensuring we are environmentally and socially responsible in the way we provide services.

The activities and investments in this Final Plan are designed to achieve these objectives. The chapters that follow will discuss our plans in the context of these objectives alongside the requirements of the NGL and NGR (see Attachment 1.6).

We also publicly report under our Vision, most recently in our 2019 Annual Review (Attachment 2.1).

2.3 Our values

Our values of respect, trust, perform and one team drive our culture, how we behave and how we make decisions. As the owner and operator of critical infrastructure providing essential services to Australians, we must ensure we act with integrity and do the right thing for current and future generations.

Our vision

To be the leading gas infrastructure business in Australia. By achieving top quartile performance on our targets.

Delivering for customers

- Public safety
- Reliability
- Customer service

A good employer

- Health and safety
- Employee engagement
- Skills development

Sustainably cost efficient

- Working within industry benchmarks
- Delivering profitable growth
- Environmentally and socially responsible

Our values

Drive our culture: how we behave and how we make decisions.

Perform

We are accountable to our customers and stakeholders, we are transparent on our performance and we deliver results. We continously improve by bringing fresh ideas and constructive challenge.

Trust

We act with integrity, we do the right thing, we are safe guardians of essential Australian infrastructure. We act in a safe and professional manner.

Respect

We treat our customers and our colleagues the way we would want to be treated, and we embrace and respect diversity.

One Team

We communicate well and support each other, and we are united behind our shared vision.

2.4 Delivering for customers

A central element of AGIG's vision is to deliver for our customers. We know that if we do not deliver for our customers on safety, reliability, customer service, price and sustainability they will pursue other energy solutions.

Furthering our commitment to put customers at the centre of our business, we are proud to be a founding member of the Energy Charter – giving extra visibility and accountability to this commitment. Our CEO is the current Chair of the Energy Charter CEO Forum.

The AGIG Disclosure Report developed under the Energy Charter is available at agig.com.au.

This commitment is consistent with our ongoing practice to engage with customers and stakeholders prior to providing our Final Plans to regulators. In developing this Final Plan, we have engaged with our customers through several activities. This engagement process has enabled customers and other stakeholders to inform and shape our proposals. The outcomes of this process are explained throughout this document, while the stakeholder engagement program is detailed in Chapter 5.

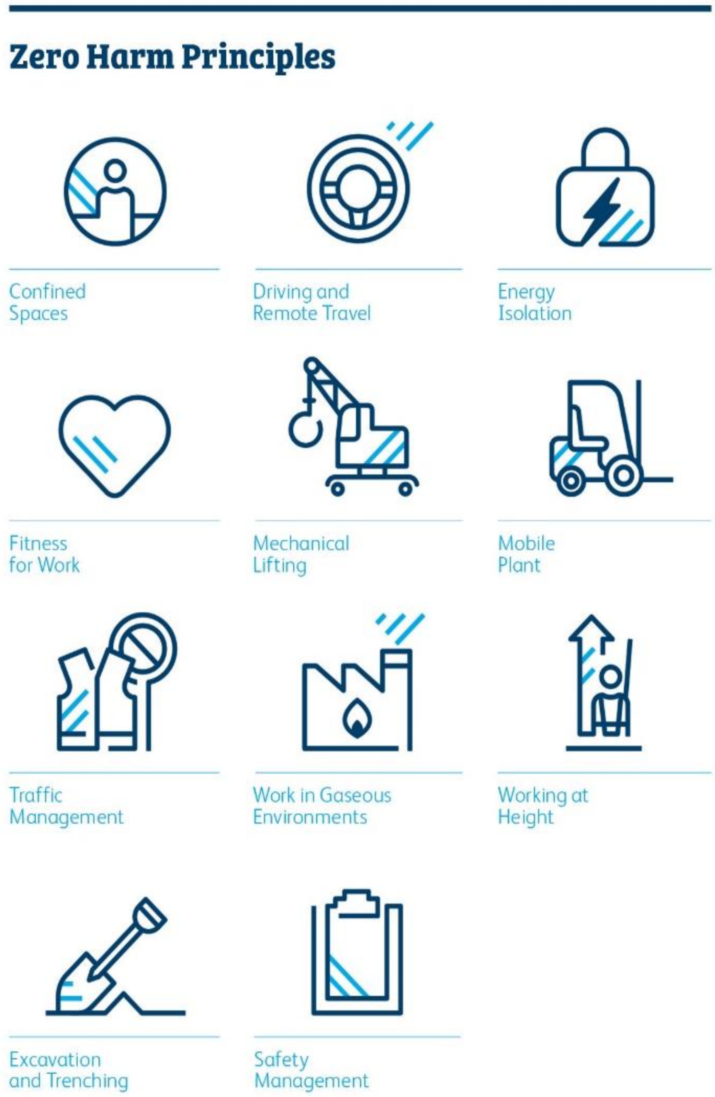
2.5 Zero Harm

Maintaining the safety of our workforce and the public is always front and centre in all of our AGIG activities. When developing our Final Plan and the work programs that underpin it, our aim is to do everything we can to continue to provide services in a safe and reliable manner.

We are continually striving to achieve Zero Harm and have comprehensive health and safety policies, procedures and training that support the delivery of this ambition.

Our Zero Harm Principles (shown in Figure 2.2) highlight areas of risk in our operations where we have non-negotiable rules for our staff and contractors to follow. These rules are essential to keep our workforce and the public safe. They also help us create a strong safety culture where every employee is personally committed to managing health and safety.

Figure 2.2: Our Zero Harm Principles



2.6 The gas supply chain

AGIG owns and operates gas infrastructure, including transmission pipelines, distribution networks and gas storage facilities across Australia. Our assets play an important role in the safe and reliable supply of gas to customers at various parts of the gas supply chain. Key components of the gas supply chain include upstream production and processing, transmission, distribution, storage and downstream consumption.

Our customers purchase gas from retailers, which is delivered directly to them through our South Australian distribution network.

2.7 Our role in South Australia

Natural gas plays a pivotal role in South Australia by providing a reliable source of energy for homes, businesses and for power generation. Gas represents almost 40% of the total energy consumption in the state.

Figure 2.3 shows the location and key features of our South Australian distribution network. The network is more than 8,100 km long, serving residential, commercial and industrial business customers in Adelaide (from Two Wells to Aldinga) and regional centres in the upper north, Barossa, Riverland and south east of the state.

2.8 Renewable gas activities

AGIG is also at the forefront of the emerging hydrogen industry in Australia through our investment in Hydrogen Park South Australia (HyP SA). HyP SA is a key part of our vision to deliver for our customers and employees and to be environmentally and socially responsible. We expect to deliver a 5% green hydrogen gas blend, produced with 100% renewable electricity, to around 700 customers in the suburb of Mitchell Park by late 2020.

Through the Australian Hydrogen Centre (AHC), we are developing feasibility studies to decarbonise gas distribution networks in Victoria and South Australia, including studies for 10% blending and 100% hydrogen networks in each state.

In Queensland, at Hydrogen Park Gladstone, we are building an electrolyser to produce renewable hydrogen for 10% blending with natural gas. This hydrogen blend will supply the entire network of Gladstone, including industry. First production is expected around the end of 2021.

In Western Australia we are also undertaking a feasibility study into blending hydrogen into the Dampier Bunbury Pipeline - the first study in Australia to consider the potential for hydrogen blending in gas transmission pipelines.

This Final Plan includes a more detailed overview of renewable gas activities in *Future of Gas* and Chapter 9.

Our Services

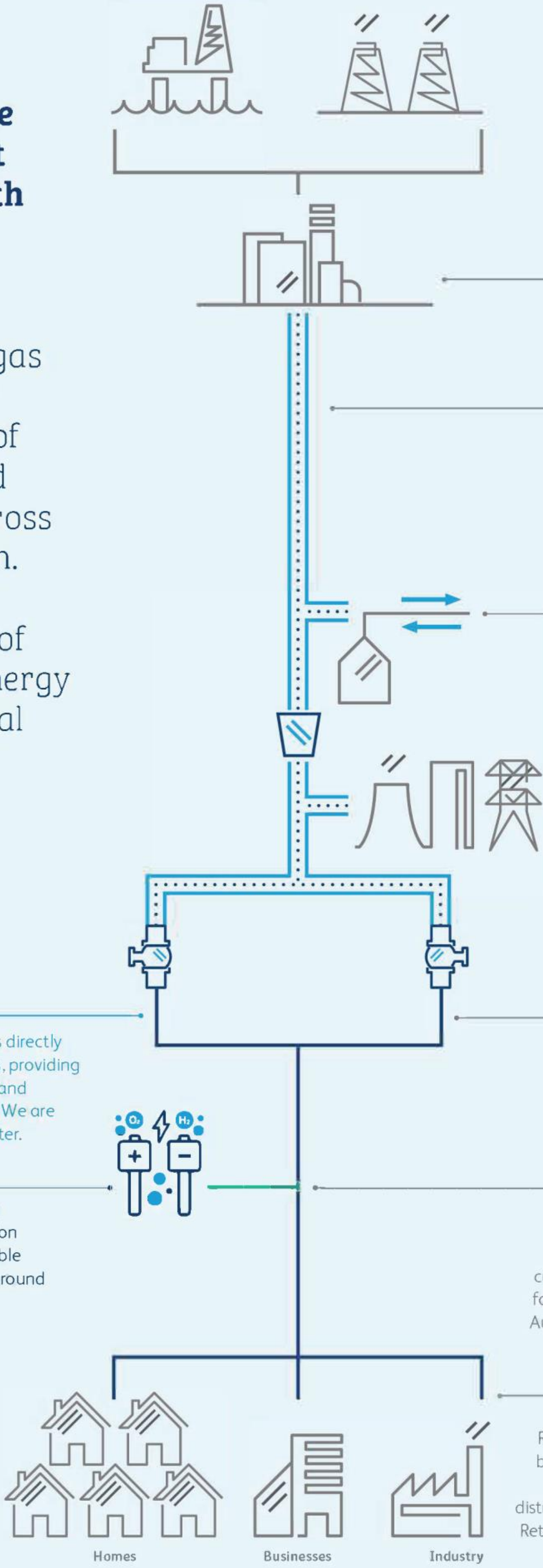
In South Australia we own and operate infrastructure that delivers gas to South Australian homes and businesses.

We do not own the gas in our networks, we deliver it on behalf of energy retailers and large customers across the gas supply chain.

We serve the needs of producers, major energy users, and residential and business users.

The Gas Supply Chain

The process in which gas is produced and used; from the field to users.



Production and processing
Onshore and offshore gas fields are drilled to access gas reserves and gas is processed to specification.

Transmission
Transmission pipelines are large high-pressure pipelines which carry gas from the gas fields/ processing plants to key markets (large users and distribution networks). At the end of transmission pipelines pressure is reduced before it enters the distribution network.

Storage
Gas storage facilities are used to balance fluctuations in gas demand.

Large users and power generation
Most large gas users such as industrial facilities and power generators connect directly to transmission pipelines to source gas for their operations.

Distribution
Low-pressure gas from transmission pipelines is distributed via a network of pipelines in towns and cities to customer sites.

Our **distribution networks** deliver gas directly to homes and small business customers, providing essential energy for hot water, heating and cooking for over two million customers. We are also responsible for reading the gas meter.

Renewable gas
The gas sector's vision for the future includes supplying renewable/carbon-neutral gas to customers. Biomethane or renewable hydrogen facilities are currently under construction across Australia, with first renewable gas injection in to distribution networks expected in 2020.

Our **renewable gas facility** Hydrogen Park South Australia will begin production in mid-2020. We will supply this renewable hydrogen blended with natural gas to around 700 customers.

Retail
Residential, commercial and industrial customers buy gas from retailers. Retailers contract with gas producers, gas transmission pipelines and gas distribution networks to enable supply to customers. Retailer's bill customers for providing these services.

- AGN Services
- Non-AGN Services

Figure 2.3: South Australian Gas Infrastructure Network

3 Our track record

IN THIS CHAPTER:

In 2019 we achieved our highest ever annual customer satisfaction score of 8.4, and have scored 8.5 out of ten so far in 2020.

We will have connected around 8,000 new customers per year in this AA period, bringing our total customer base to over 460,000.

We have completed or are on track to complete major projects including the Adelaide CBD mains replacement.

We expect to extend the network to Mount Barker bringing natural gas to one of South Australia's fastest growing regions.

In the current AA period (2016/17 – 2020/21) we have continued to deliver the strong safety, reliability and service performance expected by our customers.

Our focus in the current AA period has been on maintaining the safety and reliability of the network, improving our customer service, and reducing costs.

In accordance with our vision, our aim is to be the leading gas infrastructure business in Australia by achieving top quartile performance on all of our key targets.

Our activities throughout the current AA period have been guided by our key objectives of delivering for customers, being a good employer and being sustainably cost efficient. Figure 3.1 summarises our performance in the current period to date against our vision.

Overall, we have delivered against our vision, including delivering strong safety, reliability and customer service.

3.1 Delivering for customers

We deliver for customers by maintaining public safety, reliability and customer service standards. In the current period to date we have delivered:

- a 21% price cut to our customers on 1 July 2016;[1]
- strong public safety performance – responding to 99% of publicly reported leaks within 2 hours;
- very high reliability – with our customers experiencing one hour off supply every 40 years on average;
- 94% of emergency calls have been answered within 30 seconds in 2020 so far, with an average time to answer of 8.4 seconds; and
- customer satisfaction scores have continued to increase, to 8.5 so far in 2020, our highest score ever.

3.2 A good employer

To be a good employer we focus on the health, safety, engagement, skills and training of our workforce. In the current period to date:

- the Total Recordable Injury Frequency Rate (TRIFR) has averaged 10.6 across AGN since we began tracking this metric in 2018;
- we have introduced a number of health and safety initiatives, including annual zero harm workshops, a HSE culture model and reporting and HSE recognition awards;
- employee engagement scores have remained at or near the top decile for our industry, averaging 76%; and

[1] NB Price changes and bill impacts in this Chapter are expressed in nominal terms (i.e. after the impact of inflation) in response to stakeholder feedback. For an overview of price changes in real terms please see Chapter 13.

- 99% of compliance training has been completed within the required timeframes.

3.3 Sustainably cost efficient

To be sustainably cost efficient we focus on working within industry benchmarks, delivering profitable growth and being environmentally and socially responsible. In the current period:

- we will deliver over 1,000 km of replacement of our oldest mains, consistent with the volume of replacement expected for this period;
- Adelaide CBD mains replacement is on track for completion, which will see all mains classified as high risk replaced by the end of the current AA period;
- opex is expected to be 17% below our allowance reflecting a one-off change in our business structure as a result of our merger with AGIG in 2017, the benefits of which are passed onto customers in our proposals for 2021/22-2025/26;
- $12 million was invested to upgrade the Southern metro network and to connect McLaren Vale and other new developments;
- we expect to complete the gas pipeline to Mount Barker, bringing natural gas to one of South Australia's fastest growing regions (by the end of the current AA period).

We are also making significant progress in delivering a sustainable future for our South Australian distribution network:

- HyP SA will begin delivering a hydrogen/natural gas blend to 700 customers in Mitchell Park around the end of 2020; and
- the Australian Hydrogen Centre is developing plans for the wider decarbonisation of regional towns and ultimately the whole South Australian network.

These activities lay the foundation for the long-term future of our network as we work to achieve net-zero emissions by 2050 across the whole energy sector.

Figure 3.1: Our performance against our vision in current period (2016/17 to date, with forecast performance to the end of the period where applicable)

Vision

Delivering for customers

Which means

- Public safety
- Reliability
- Customer service

Our performance 2016/17 to date

- 21 % (after inflation) price cut to our customers on 1 July 2016
- Strong public safety performance – responding to 99 % of publicly reported leaks with 2 hours
- Very high reliability – one unplanned outage every 40 years on average
- 94 % of emergency calls answered within 30 seconds
- 100 % of leak survey completed
- Customer satisfaction survey scored an average of 7.4, and 8.5 so far in 2020, our highest score to date
- Around 8,000 new connections per annum, with 99 % complete within the required 20 days
- The proportion of complaints resolved within 2 days has increased to 88 % in 2019

Vision

A good employer

Which means

- Health & Safety
- Employee engagement
- Skills development

Our performance 2016/17 to date

- Total recordable injury frequency rate average of 10.6 in 2018 and 2019
- Employee engagement annual average score of 7.6, remaining within or near the decile every year
- Compliance training 99 % completion

Vision

Sustainably cost efficient

Which means

- Working within industry benchmarks
- Delivering profitable growth
- Environmentally and socially responsible

Our performance 2016/17 to date

- Mains replacement: on track to deliver over 1,000km consistent with the benchmarks set for the current period
- Operated within the opex and capex benchmarks set for the business
- On track for Adelaide CBD mains replacement
- Started the process of delivering a low carbon future with the delivery of HyP SA, the largest renewable hydrogen facility of its type
- Expected delivery of a gas pipeline to serve Mount Barker


Gas Meter
Australian Gas Networks

4 What we will deliver

IN THIS CHAPTER:

We will continue to deliver for customers in the next AA period connecting around 39,000 new customers to the network.

We will replace around 860 km of mains, completing the replacement of the highest risk mains in our network.

We will complete the replacement of all cast iron mains in the network, a significant safety milestone for our customers and our business.

An upfront price cut of 7% (after inflation) builds on price cuts of 21% (after inflation) delivered at the beginning of the current period.[1]

By 2025/26, customers will be paying more than 20% less (before inflation) than what customers paid in 2015/16.

Our Final Plan reflects our vision to be the leading gas infrastructure business in Australia, continuing to deliver on the priorities of our customers – affordable, safe and reliable services now and into the future.

Customers have been at the centre of our planning for the next AA period. Based on their feedback, we will continue to focus on providing high levels of community safety, network reliability and customer service, at a lower price than they pay today.

Our Final Plan provides further reductions in our prices by investing efficiently in our assets and operations. Highlights of what we will deliver are included in Figure 4.1 and are described in more detail in the sections that follow.

Our Final Plan also makes some adjustments, relative to the Draft Plan, in response to the COVID-19 pandemic. The pandemic has particularly had implications for our forecast new connections which are now forecast to be 9% lower than in the Draft Plan. Our plans have been informed by our robust stakeholder engagement program and are based on the best information available to the business.

The pandemic has had a significant economic and social impact for many South Australians and therefore it was more important than ever, that our Final Plan deliver network price relief.

4.1 Delivering for customers

Delivering for our customers means ensuring public safety and high levels of reliability and customer service.

Our customers expect that we maintain the safety and reliability of the network. In the next period we will deliver for customers by:

- responding to public leak reports within 2 hours more than 95% of the time;
- repairing leaks within the timeframes set by our Leak Management Plan 100% of the time;
- achieving customer satisfaction scores at or above 8.2;
- connecting around 39,000 new residential, business and industrial customers;
- replacing a further 860 km of old cast iron, unprotected steel and first-generation plastic pipes. We will replace all of our old cast iron mains by the end of the next period, which is a significant safety milestone for our customers and the business;

[1] NB Price changes and bill impacts in this Chapter are expressed in nominal terms (i.e. after the impact of inflation) in response to stakeholder feedback. For an overview of price changes in real terms please see Chapter 13.

- responding to customer and community expectations to commence the transition to a low carbon gas supply including by providing renewable gas to meet our requirement for unaccounted for gas;
- $31 million on projects and programs to continue to meet the service expectations of our customers, including:
  - our ongoing meter replacement program ($19 million);
  - investment in our IT systems that support our customer service functions ($8 million); and
  - providing more digital services and a greater variety of communication channels ($3 million).

We are also taking forward three new proposals shaped by our customers during our engagement program:

- offsetting up to 20% of our UAFG with renewable gas;
- implementing a Vulnerable Customer Assistance Program (VCAP); and
- introducing an innovation allowance.

4.2 A good employer

Being a good employer means prioritising the health and safety of our employees, focussing on employee engagement and skills development.

Investing in our workforce helps ensure we can continue to deliver services that meet our customers' expectations.

In the next period we will be a good employer by:

- continuing to target zero harm through workshops and embedding our HSE culture model throughout the business;
- continuing our health and safety initiatives, including our various wellbeing initiatives;
- maintaining top decile employee engagement scores to ensure we remain customer and safety focussed.

4.3 Sustainably cost efficient

Being sustainably cost efficient means working within industry benchmarks, delivering profitable growth and being environmentally and socially responsible.

In the next period we will be sustainably cost efficient by:

- delivering an upfront price cut of 7% (after inflation) on 1 July 2021, which builds on price cuts delivered by our business in the current period (see Table 4.1);
- maintaining combined operating and capital expenditure at similar levels, despite our network growing in size and customer numbers;
- taking the first steps to develop options for the long-term future of the South Australian distribution network as the state works towards net-zero emissions by 2050 such as:
  - offsetting up to 20% of our unaccounted for gas (UAFG) with renewable gas (biomethane); and
  - proposing a network innovation scheme, delivering the innovation required for the long-term future of the network and to meet the long-term interests of our customers.

Table 4.1: Savings ($ nominal) when:

- The average residential customer spends $510 on the distribution component of their annual gas bill;
- The average commercial customer spends $5,016 on the distribution component of their annual gas bill;
- The average industrial customer spends $261,315 on the distribution component of their annual gas bill.

	Domestic	Commercial	Industrial
From 1 July 2021 (6.5% price cut)	45	445	23,190
From 1 July 2022 (2.8% price increase)	40	392	20,442
From 1 July 2023 (2.8% price increase)	34	337	17,567
From 1 July 2024 (2.8% price increase)	28	280	14,561
From 1 July 2025 (2.8% price increase)	22	219	11,420
Total Savings for the five-year period July 2021 – June 2026	**$170**	**$1,673**	**$87,181**

Note: Table may not add due to rounding
We have assumed for the purposes of the price comparison that inflation in years 2-5 of the next AA period will be 1.5%

Figure 4.1: Our performance targets for the 2021/22 – 2025/26 period

Vision

Delivering for customers

Which means

- Public safety
- Reliability
- Customer service

Our performance targets for 2021/22 – 2025/26

- 90 % of emergency calls answered within 10 seconds
- >95 % of publicly reported leaks responded to within two hours
- 100 % of priority leaks repaired in timeframes set out in our leak management plan
- 100 % of leak surveys completed on time
- Customer satisfaction survey score above 8.2
- Around 39,000 new connections with more than 98 % complete within the required 20 days
- 80 % of complaints resolved within two days

Vision

A good employer

Which means

- Health & Safety
- Employee engagement
- Skills development

Our performance targets for 2021/22 – 2025/26

- Total Recordable Injury Frequency Rate (TRIFR): <7
- Employee engagement score remaining within or near the top decile every year
- Compliance training 99 % completion

Vision

Sustainably cost efficient

Which means

- Working within industry benchmarks
- Delivering profitable growth
- Environmentally and socially responsible

Our performance targets for 2021/22 – 2025/26

- Providing an initial price cut of 7 % (after inflation) on 1 July 2021 with a 2.8 % increase each year thereafter, building on the 21 % price cut on 1 July 2016
- Around 860km of mains replacement, comprising our low pressure and some early generation HDPE higher pressure mains. This program will see the removal of all of our old cast iron mains, a significant safety milestone for our customers and the business
- Maintaining combined operating and capital expenditure at current levels, while our network continues to grow
- Taking the first steps to secure the long-term future of the South Australian distribution network including
  - offsetting 20 % of our unaccounted for gas (UAFG) with renewable gas (biomethane)
  - investing to support vulnerable customers; and
  - proposing a network innovation scheme.

Figure 4.3: Forecast Average Residential Distribution Charge (bars), compared with CPI increases (dashed line) ($Nominal)

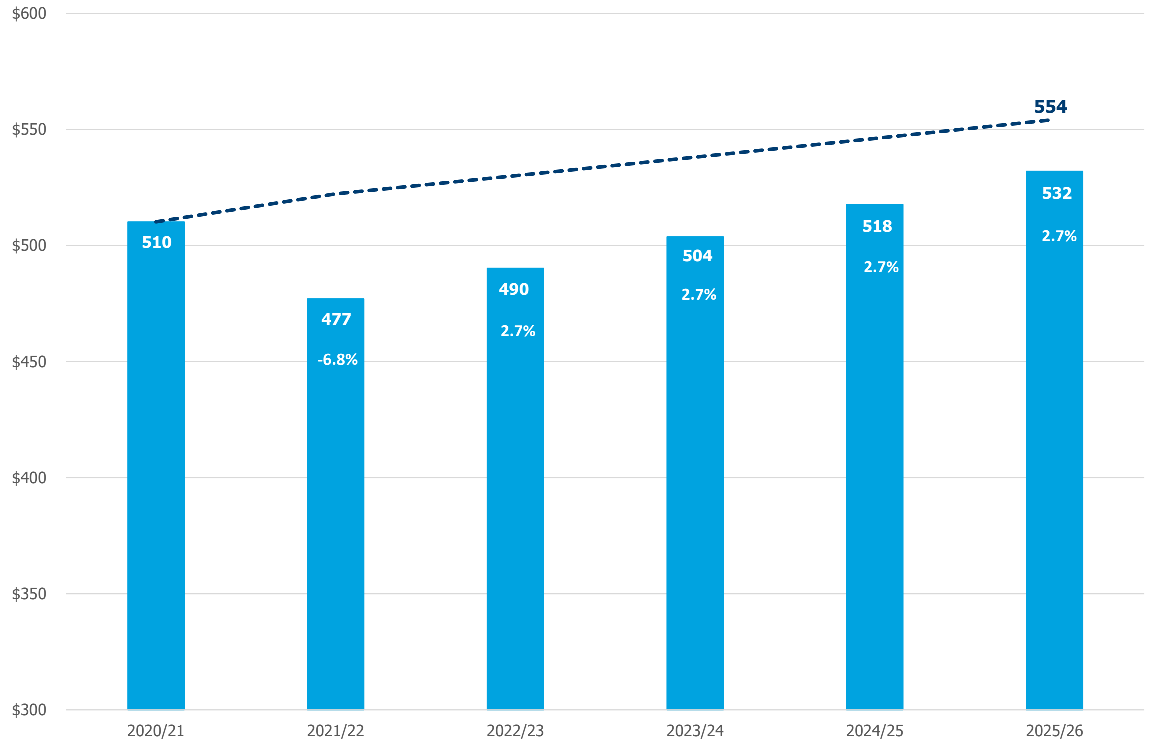


Figure 4.2: Forecast Average Commercial Distribution Charge (bars), compared with CPI increases (dashed line) ($Nominal)

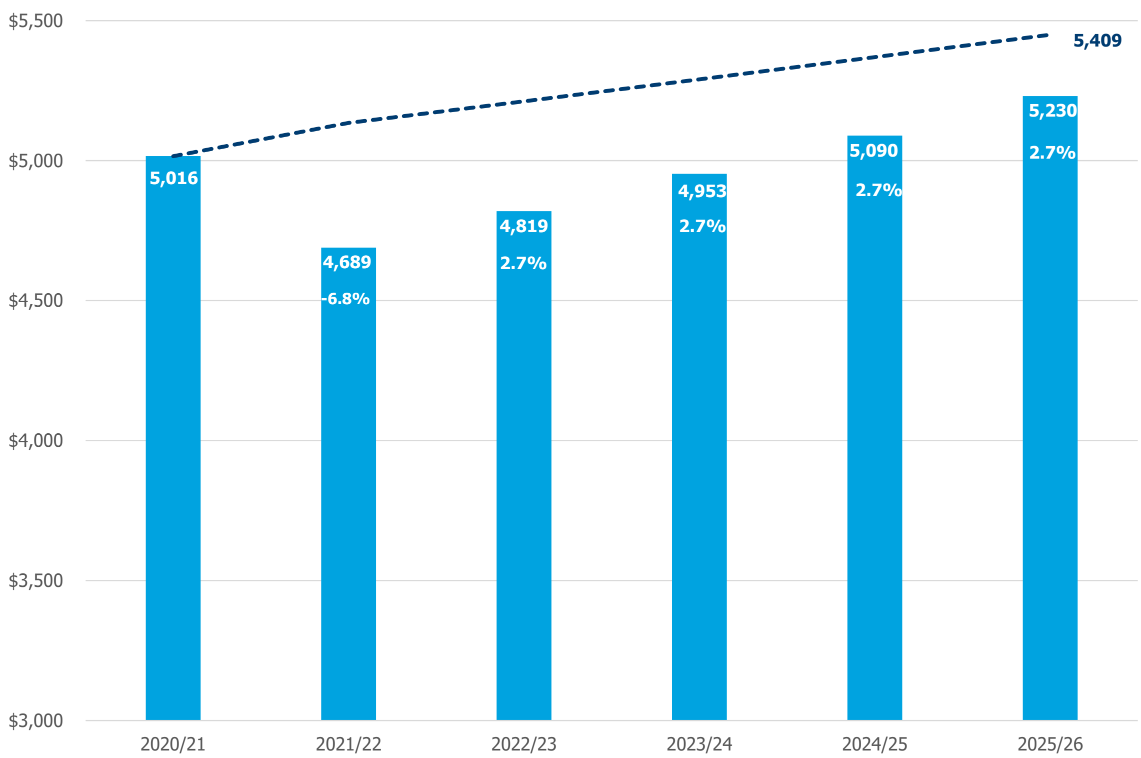
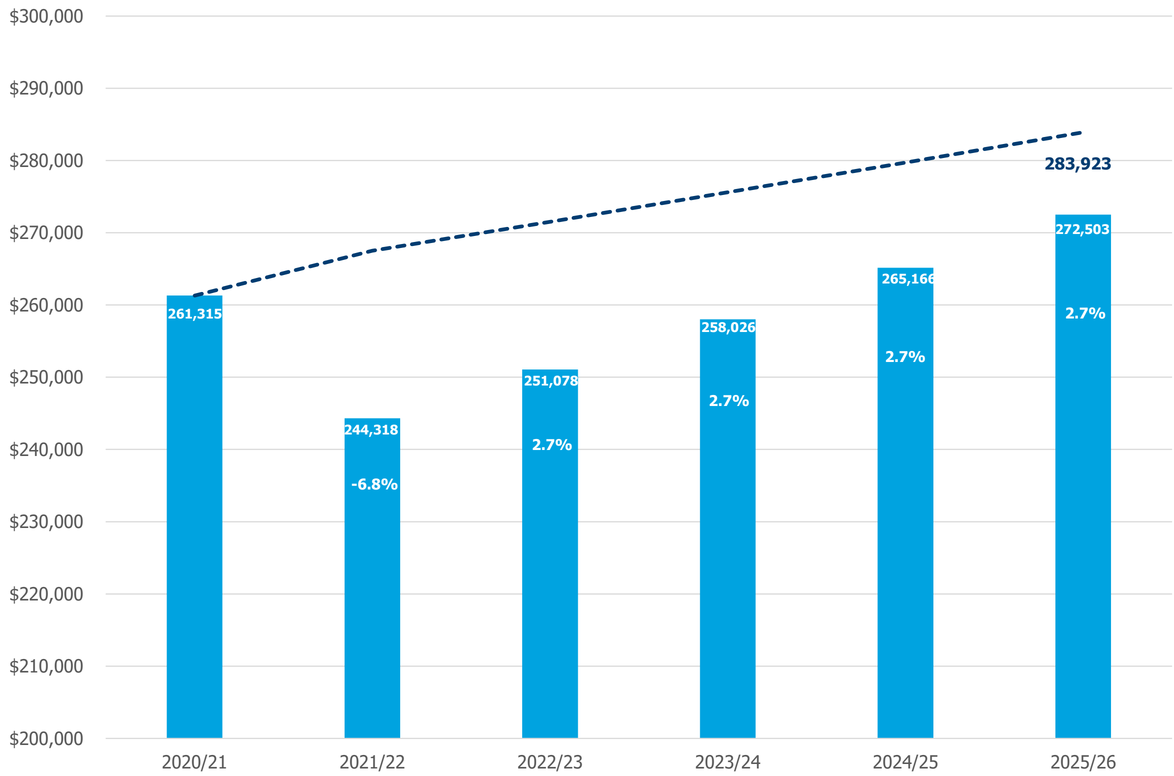


Figure 4.4: Forecast Average Industrial Distribution Charge (bars), compared with CPI increases (dashed line) ($Nominal)



Future of gas

The energy sector is rapidly changing

Since the beginning of the current AA period, there has been significant change in the energy sector with global, national and state commitments to reducing emissions. The period has also seen the widespread deployment of renewable electricity in South Australia – accounting for over 50% of the state's electricity generation in 2019.[1]

There is a growing recognition that cleaner energy sources with zero or net zero emissions need to replace existing sources from fossil fuels by 2050. Natural gas has a particularly important role to play given the prominent role it plays in South Australia's energy sector.

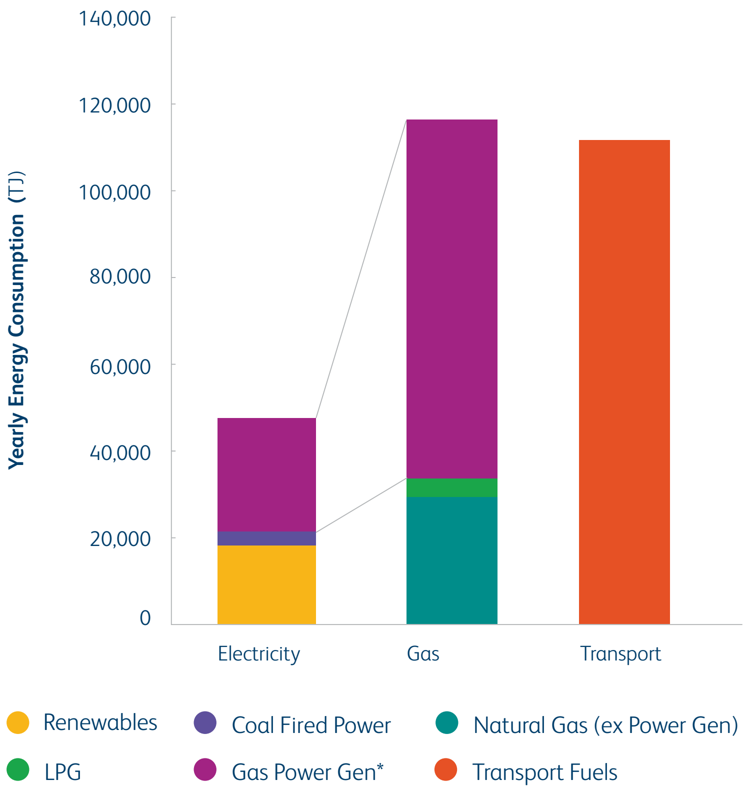
Gas Vision 2050 reflects the ambitions of key organisations which represent Australia's gas sector, including AGN.[2] It shows that gaseous fuels have a pivotal role to play in Australia's low carbon future to 2050 and beyond.

Gas Vision 2050 represents a pathway with several phases of activity, most recently updated in October 2019.[3]

Phase 1 of the pathway is to demonstrate the technical feasibility and safety of blending hydrogen into the network at varying percentages. Phase 1 is set to conclude by around 2022, by which time we should have a clearer idea of the feasibility of the transition to hydrogen, including the policy direction of government.

Our own progress at HyP SA is a demonstration that this first phase is progressing well.

South Australia's Total Yearly Energy Consumption (FY2017/18)



Note: Gas power generation fuels have been included both electricity consumption and in gas consumption in this chart. Transport fuels do not include aviation.

[1] Australian Government, Australian Energy Statistics, Table O Electricity generation by fuel type 2018-19 and 2019

[2] Energy Networks Australia (2018) Gas Vision 2050: reliable, secure energy and cost-effective carbon reduction

[3] Energy Networks Australia (2019), Hydrogen Innovation – Delivering on the Vision

Our network will continue to deliver

We recognise that if South Australia is to meet its emission reduction targets we need to focus on large-scale decarbonisation of our South Australian distribution network. We are actively pursuing these opportunities through hydrogen and biomethane projects. Gas distribution networks provide a ready market and the infrastructure capable of decarbonising residential and industrial heat through the use of renewable gases like hydrogen and biomethane.

We are therefore working closely with partners in government, industry and amongst our stakeholders to make a renewable gas future a reality.

HyP SA and the Australian Hydrogen Centre (see Section 2.8) are laying a foundation for a strong zero emissions future.

Actions for the next AA period

Consistent with Gas Vision 2050, we are including various initiatives to further the transition to renewable gas in the next AA period. These actions have low costs, strong customer support, and strong benefits for customers. Furthermore, these actions can be taken in the next AA period while still delivering a network price cut for our customers.

UAFG

During our engagement program 87% of participants noted that finding ways to lower emissions was very or extremely important to them.

In this light, 84% were supportive or strongly supportive of measures to replace our UAFG with renewable gases like hydrogen or biomethane (see Chapter 5).

We are therefore proposing to use renewable gas for approximately 20% of our UAFG requirements and have provided further detail on this initiative in Chapter 7.

Mains replacement

We are replacing a further 860 km of old cast iron, unprotected steel and first-generation plastic pipes. We will replace all of our old cast iron mains by the end of the next period. While this is a significant safety milestone for our customers and the business, it has the added benefit of helping to make our network hydrogen ready (see Chapter 8).

HyP SA

HyP SA will be integrated with the local network in Mitchell park throughout the next period – delivering a 5% renewable hydrogen blend to around 700 customers. The aim is to demonstrate the technical viability and safety of this important technology (see Section 2.8).

Innovation allowance

We are also proposing an innovation allowance, which was supported by almost 8 in 10 customers in our engagement program. The Innovation Allowance will provide a clear framework (including rules and requirements) for funding of innovative projects over the next AA period, including but not limited to renewable gas projects. More information is available in Chapter 11.

"The development of our hydrogen resources could enhance Australia's energy security, create Australian jobs and build an export industry valued in the billions." [4]

National Hydrogen Strategy

Biomethane

Biomethane is the net-zero emission gaseous fuel recovered from a wide range of renewable sources, such as wastewater, food waste and landfill. Because the gas is recovered from other sources (preventing it from entering the atmosphere), it can be a source of net zero emissions. More importantly, biomethane can be produced to have much the same composition as natural gas today, meaning it can be injected into our networks with no modification to the network or user appliances.

Hydrogen

Hydrogen can be used much like natural gas to heat homes, power vehicles and produce electricity, but importantly when burned it produces only water vapour and energy as heat, with no carbon emissions. If produced from water using electrolysis powered by renewable electricity hydrogen is zero emissions. Blended at low volumes with natural gas, hydrogen is likely to require no need for modification to existing appliances or the network. However, higher volumes of hydrogen will require some modification to account for the different characteristics of hydrogen and methane.

[4] COAG Energy Council, Australia's National Hydrogen Strategy, 2019

Future of gas

When should we act?

The actual future of gas networks will be determined by a combination of government policy, technology developments and the cumulative decisions of millions of customers.

Government policies to achieve net zero emissions will emerge and evolve over time. Technologies will also evolve, lowering in cost and responding to customer needs. Finally, customers will make choices about the types of energy most appropriate for their needs as emissions reduce and the relative prices of different technologies change.

Gas is a fuel of choice today and options are likely to increase in the future - our customers choose to connect because of benefits like affordability, reliability, comfort and convenience. Nonetheless, we can see the potential for more competition in the future (as renewable energy becomes less expensive.

The future presents network businesses and the AER with a challenge – how do we manage this uncertainty while promoting the efficient investment and operation of natural gas services in the long-term interests of customers?

At a high-level we see two possible approaches for assessing the implications of the evolving energy landscape for the South Australian distribution network. One which would prematurely lock-in a definite outcome – a binary approach – and a second that minimises the impacts while leaving options for the future - a risk assessment approach or real options framework.

- Under a binary approach a regulator makes a one-off decision: is there a renewable gas future for the gas network? If the answer is yes, networks continue to invest in network assets, including renewable gas assets, and economic lives of assets are maintained well into the future. If the answer to this question is no, there is an effective end date for the network (whether or not renewable gas is viable); economic lives and new investment are limited by the end date.

  This binary approach fails to appropriately consider the variety of options available in the emerging energy market. It locks in a future despite remaining uncertainty, and becomes a self-fulfilling prophecy with potentially significant negative outcomes for customers whose choices will be limited as a result.

  This approach should only be implemented if there is complete information (or no uncertainty), particularly given the significant (around $1.7 billion) investment already made in the South Australian gas distribution network. Furthermore, substantial additional investment would also be required to augment the electricity distribution system to supply the energy currently delivered by the gas network.

- Under a risk assessment approach (or a real options framework) networks and regulators assess future pathways for technological and policy change, the way the market will evolve in response, and what these pathways mean for demand on the network. Networks and regulators assess the consequences of each scenario and the degree to which proposed actions might create more flexibility in dealing with the future (within the constraints of each scenario). This is known as a “real options” perspective and we believe is well suited to consider the future of gas networks.

  Under this approach depreciation can change to help ensure that investment in assets is recovered and help to create a smooth transition to zero emissions for investors and customers.

We believe a risk assessment framework is appropriate. A particular focus is given to depreciation because this is the building block we think is the best way to deal with future risk. We also believe a risk assessment framework is compatible with the approach to depreciation in the NGR (rule 89) as it enables changes in economic lives to be reflected over time.

A change to depreciation via a change in economic lives needs to be assessed and acted on in a transparent and robust manner. We will never understand exactly what the future holds, and planning will always occur in the face of uncertainty. But a framework which transparently and robustly treats the best information available today serves to enhance customer and investor confidence.

While we have begun to consider possible pathways the energy sector might take and the changes we could start to make now, such changes may have implications across networks and for customers across Australia. Developing the right approach should be subject to wider consultations with the AER, customers, stakeholders and networks as was recommended by CCP24.

For our South Australian network, on a balance of factors we believe it is too early to act to adjust depreciation in the next AA period. As noted above, efforts to decarbonise gas distribution networks are in the early stages. From around 2022 we will be better informed about the progress of hydrogen to make a decision. Furthermore, as outlined in Chapter 9 our early assessment suggests that a case can be made to delay action for the South Australian network until the subsequent AA period (beginning in July 2026).

Finally, the approach adopted reduces potential price volatility between AA periods.

5 Customer and Stakeholder Engagement

Our Final Plan is underpinned by effective customer and stakeholder engagement. With customers at the centre of our planning, our Final Plan responds to customer needs and expectations for services, both now and in the future.

IN THIS CHAPTER:

We held 22 workshops with customers in 5 locations over 3 phases to allow customer input to inform and shape the development of our plan.

We received strong support from our customers, with 96% of customers supporting our plan.

We have worked together with two reference groups of consumer representatives and retailers, who have also inputted into, and have indicated broad support for our plan.

We have engaged extensively with a broad cross section of customers and stakeholders throughout the process of developing our Final Plan.

This input has informed and shaped the development of our Final Plan. It is a plan we developed with an objective of being capable of acceptance by our customers.

Our Final Plan has high levels of customer and stakeholder support.

This chapter explains our customer and stakeholder engagement program, the activities we have undertaken, the feedback we received, and how this feedback has influenced our plans.

5.1 Overview

Our objective is to develop a Final Plan which delivers for current and future customers, is underpinned by effective stakeholder engagement and is capable of being accepted by our customers and stakeholders.

We adopted a four staged approach to our engagement program, which is illustrated in Figure 5.1. We use this framework to report the outcomes against our engagement activities.

In February 2019 we consulted on our draft engagement strategy as part of Stage 1. We believe this a critical step in the process as it ensures our engagement program is fit for purpose and identifies key topics for consultation early in the process.

In July 2019 we published our *Stage 1 Customer and Stakeholder Engagement Report*, (Attachment 5.1) which summarised key insights from our early engagement and documented our final engagement plan.

Our Final Plan objectives:

- ✓ Delivers for current and future customers
- ✓ Is underpinned by effective stakeholder engagement
- ✓ Is capable of being accepted by our customers and stakeholders

Figure 5.1: Our Four Staged Approach to Customer and Stakeholder Engagement

Stage 1
Strategy and research

Feb - May 2019

Purpose
We engaged with stakeholders to better understand customer needs and to consult on our proposed engagement approach.

IAP2 Spectrum
CONSULT/INVOLVE

Engagement Activities
- In April 2019 we published and distributed our Draft Customer and Stakeholder Engagement Plan for consultation
- We expanded our South Australian and Retailer Reference Groups
- We continued to meet regularly with our reference groups, Government agencies and key stakeholders
- We established partnerships with stakeholders for engagement with the broader community and customers.

Key Deliverables
Stage 1 Engagement Report

We published our engagement strategy: Stage 1 Stakeholder Engagement Report.

Stage 2
Developing our Draft Plan

May 2019 - Feb 2020

Purpose
In this stage we ran a series of engagement activities designed to inform the development of our Draft Plan.

IAP2 Spectrum
INVOLVE/COLLABORATE

Engagement Activities
- We held regular meetings with our South Australian and Retailer Reference Groups and key stakeholders
- We launched our online engagement portal Gas Matters
- Stakeholders were kept updated through our website and Gas Matters
- We held information sessions to help stakeholders gain a better understanding of the gas industry and current issues
- We met with and surveyed large industrial customers
- We held iterative workshops with a broad cross section of customers across South Australia
- We held 3 co-design workshops with industry experts to consider how we could further assist vulnerable customers.

Key Deliverables
Stage 2 Engagement Report

We published summary reports of customer and stakeholder input into developing our Draft Plan and outcomes of our co-design workshops.

Stage 3
Consultation on our Draft Plan

Feb - Apr 2020

Purpose
In this stage we focussed on public consultation on our Draft Plan.

IAP2 Spectrum
CONSULT/INVOLVE

Engagement Activities
- We published and distributed our Draft Plan to stakeholders, customers and Government agencies
- We held 3 meetings of our combined SA and Retailer Reference Groups
- Stakeholders were kept updated through our online portal, Gas Matters
- We held 7 seperate Phase 3 customer workshops in metropolitan and across regional South Australia
- We held our fourth meeting of our Co-design stakeholder group

Key Deliverables
Draft Plan

We reported on all customer and stakeholder feedback and how feedback influenced our plans.

Stage 4
Refinement and engagement

Apr - June 2020

Purpose
Consultation feedback from Stage 3 was used to finalise our plan.

IAP2 Spectrum
INFORM/INVOLVE/CONSULT

Engagement Activities
- We held 3 meetings of our South Australian and Retailer Reference Groups to show how feedback was used to inform our Final Plan, and also to provide members with an opportunity to shape the Final Plan
- We published the Draft Plan submissions on Gas Matters

Key Deliverables
- Final Plan to the AER on 1 July 2020
- Final Customer Engagement Report
- Final Plan Customer Overview

Our Customer and Stakeholder Engagement Process

We commenced our customer and stakeholder engagement program around 16 months prior to lodgement of this Final Plan.

We delivered a range of engagement activities with customers and stakeholders to support the development our plans, including:

- ✓ 7 South Australian Reference Group (SARG) Meetings;
- ✓ 5 Retailer Reference Group (RRG) Meetings;
- ✓ 4 combined SARG and RRG workshops and meetings on our Draft Plan proposals;
- ✓ 22 interactive workshops with residential and business customers (conducted over 3 phases);
- ✓ a major (large user) customer survey;
- ✓ 3 co-design workshops with experts from the social service sector on the topic of vulnerable customers; and
- ✓ online engagement on Gas Matters.

Our engagement journey is illustrated in Figure 5.2 and shows our iterative engagement process with customers and stakeholders.

Critical to our program has been the ongoing engagement with our two stakeholder reference groups through a series of meetings and workshops.

Membership of SARG reflects the diversity of our customer base, with organisations representing residential customers, vulnerable customers, older Australians, multicultural communities, business and industrial customers, builders and developers, and local government.

The RRG comprises representatives from gas retailers who operate in national markets which we serve, including South Australia.

Through regular meetings and workshops we consulted with stakeholders on topics including:

- our pipeline services;
- customer experience and flexible solutions;
- our price structure;
- our capex and opex proposals;
- demand forecast;
- rate of return;
- incentives;
- setting our capital base; and
- future of gas

A list of engagement topics discussed at meetings and workshops is shown in Table 5.6, Table 5.7 and Table 5.8 in Section 5.5.3 of this chapter.

Key areas of interest that we worked together with stakeholders were:

- the price path, and how price is communicated more broadly with customers and the community;
- investment to maintain current levels of public safety, reliability of supply and customer service;
- ensuring our approaches to investment are appropriate and that our levels of investment are efficient;
- how we are responding to decarbonisation and the customer and price impacts in this Final Plan and subsequent regulatory processes; and
- ensuring our Final Plan responds to the social and economic impacts of COVID-19.

A full list of feedback from our reference group members across the stages of our engagement program and how we have responded is included in Attachment 5.2.

We also actively engaged and met regularly with members of the AER's Consumer Challenge Panel (CCP24). CCP24 were invited to attend and observe our engagement activities.

The CCP assists the AER to make better regulatory determinations by providing input on issues of importance to consumers. The role of the CCP is to provide input and to challenge the AER on key consumer issues during a network determination. The CCP also advises the AER on the effectiveness of our engagement process.

Key discussion with the CCP and how we have responded in our Final Plan is covered in section 5.5.3 of this chapter.

Regular customer engagement allowed us to develop our plans iteratively

Engaging directly with customers in the development of the Final Plan is an important part of our engagement program to ensure we respond to customer needs and expectations.

Our customer engagement workshops were run in three phases with the same groups of customers, allowing iterative engagement as our plans were developed. We held dedicated workshops for residential, business, metropolitan, regional and culturally and linguistically diverse (CALD) customers.

Repeat engagement with the same groups of customers enables us to:

- ✓ build customer knowledge over time to allow customers to make informed decisions;

- ✓ listen, test and validate our ideas in response to customer feedback as we develop our proposals; and
- ✓ prioritise and explore issues in more detail in response to customer feedback.

Three phases of workshops were held in five locations across South Australia with a total of 127 AGN customers in each phase (319 participants across the three phases and 22 workshops).

Customer workshops were facilitated by an independent third party (KPMG) to capture and report how customer feedback was captured and documented.

Across the three workshops we covered the following topics with customers: price and affordability; reliability of service; public safety; customer service; sustainability; and innovation.

The first phase of workshops were designed to understand customer values, needs and service expectations.

In the following phase of customer workshops we validated customer feedback, explored issues of importance further and tested costed proposals for feedback.

And in the third phase we presented Draft Plan proposals to customers and further explored key issues including innovation, education, sustainability and vulnerable customer assistance. More detail about the information we presented at customer workshops, the questions we asked and their feedback is outlined in section 5.5.1 of this chapter. A full customer engagement report by KPMG is included in Attachment 5.3.

We collaborated with stakeholders to design improved services for vulnerable customers

We are committed to delivering for all customers, including ensuring our services are accessible and safe for those who are most vulnerable in our community.

As part of our Stage 2 engagement activities we included a series of three co-design workshops with stakeholders on the topic: *How might AGN better support vulnerable customers – now and in the future?*

Workshop participants were experts from the social and community services sector including financial hardship, disability, mental health, culturally and linguistically diverse (CALD) people, and older Australians.

Prioritised ideas were captured by KPMG and documented in a Final Report (Attachment 5.3). Feedback from the co-design workshops and how we are responding is addressed in section 5.5.3 of this chapter.

Findings from the customer workshops are summarised as follows:

- ✓ Price and affordability are the most important issues for customers, and customers welcome the proposed price cut
- ✓ 96% of customers support AGN's Draft Plan and investment proposals
- ✓ AGN is trusted for its delivery of safe, reliable gas and customers support investment levels to maintain these standards
- ✓ Customers value current customer service levels but expect digital services to be introduced in a cost effective way
- ✓ Environmental sustainability is a high priority for customers and there is a high level of support for investment in renewable gas to replace unaccounted for gas (UAFG)
- ✓ Customers support AGN investment in innovation
- ✓ Customers support investment in a Vulnerable Customer Assistance Program (VCAP) and consider this responsible business
- ✓ Customers consider education is important, but initiatives considered by AGN must be accessible and funding models need to be further explored

Figure 5.2: Our Customer and Stakeholder Process 2019 - 2020

Australian Gas Networks

2019

Stage 1
Strategy and Research

Jan-April
We expanded membership of our South Australian Reference Group and Retailer Reference Group

April
We published our Draft Customer and Stakeholder Engagement Plan for consultation

We asked stakeholders including our SA Reference Group, our Retailer Reference Group, Government agencies and customers if our engagement activities are appropriate for our customers and stakeholders.

17 April
South Australian Reference Group Meeting

29 April
Retailer Reference Group Meeting

We consulted with reference groups on our reference service proposal and draft terms and conditions.

Stage 2
Developing our Draft Plan

3 June
South Australian Reference Group Meeting

May-June
Meetings with key stakeholders

One-on-one meetings with key stakeholders regarding our proposed approach to engaging with customers.

24 July
Retailer Reference Group Meeting

We presented an overview of draft terms and conditions.

July
Gas Matters on line engagement portal launched

Stage 1 Stakeholder Engagement Report

Meetings with industrial customers

We invited our large industrial customers to provide input into expected demand for natural gas and the services we provide.

July – August
Phase #1 Customer Workshops

Understanding Customer Values - 127 participants including business, residential customer and culturally and linguistically diverse communities in 7 workshops in metropolitan Adelaide and across regional South Australia.


Adelaide Metropolitan


Barossa Valley


Port Pirie

7 August
South Australian Reference Group Meeting

We presented preliminary expenditure proposals

29 August
South Australian Reference Group Meeting

Adelaide Metropolitan

Culturally and linguistically diverse communities

October
Phase #2 Customer Workshops

We validated customer feedback and tested our proposals and ideas in 7 separate workshops across South Australia.

23 October
South Australian Reference Group Meeting

November
Our Reference Services Proposal for South Australia approved by the Australian Energy Retailer (AER)

November
Co-design Workshops

We collaborated with industry experts to inform decision making around how might AGN better support vulnerable customers – now and in the future.


Co-design Workshop

8 November
Retailer Reference Group Meeting

4 December
South Australian Reference Group Meeting

18 December
Retailer Reference Group Meeting

We presented our preliminary expenditure proposals, our early price modelling and information on how prices are determined through the regulatory framework.

2020

Stage 3
Consultation on our Draft Plan

17 February
Our Draft Plan for SA 2021-26

We published our Draft Plan for SA 2021-26. The Draft Plan was sent to stakeholders and customers.

18 February
South Australian Reference Group Meeting

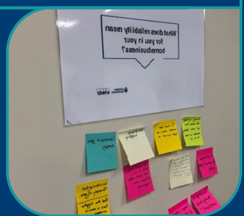
18 February
Retailer Reference Group Meeting

We provided an overview of our Draft Plan, regulatory modelling update and our Stage 3 engagement activities, including our customer workshops and proposed workshops with Reference Group members.

February - March
Phase #3 Customer Workshops

We presented our Draft Plan and proposals for the SA gas network at 7 workshops across metropolitan Adelaide and regional South Australia.


Mount Gambier


Murray Bridge

Stage 4
Refinement and Engagement

13 March
Combined Retailer and South Australian Reference Group Workshop #1

We presented our Draft Plan proposals in detail including:

- Future of Gas
- Capex
- Opex
- Incentives

9 April
Combined Retailer and South Australian Reference Group Workshop #2

We presented our Draft Plan proposals in detail including:

- Pricing
- Terms and Conditions
- Demand
- Rate of Return
- Capital Base
- Future of Gas

28 May
Combined Retailer and South Australian Reference Group Workshop #3

We presented our response to customer and stakeholder feedback on our Draft Plan proposals

17 June
Combined Retailer and South Australian Reference Group

We presented our Final Plan 2021-2026

We consulted widely on our Draft Plan

Publishing and consulting on our Draft Plans is a key step in our engagement program. It allows us to share our expenditure proposals in the context of the overall price outcome and seek feedback to refine our plans.

We published our Draft Plan in February 2020. Open for consultation for an eight week period, we published it online and distributed print copies to customer workshop participants, major customers, retailers, government agencies, reference group members and other stakeholders.

Our third phase of customer workshops was conducted during the Draft Plan consultation, which allowed direct customer feedback on the Draft Plan.

To support consultation with stakeholders on our Draft Plan we ran two deep-dive workshops combining our stakeholder reference group members. We engaged KPMG to facilitate and document feedback for participants.

We received four public submissions on our Draft Plan. We also received two separate submissions from retailers relating specifically to our draft Terms and Conditions. All submissions are included in Attachment 5.5.

Draft Plan feedback and how we have responded is discussed in sections 5.5.1, 5.5.2 and 5.5.3 of this chapter.

How have engagement activities influenced and shaped our plans?

All feedback from regular SARG and RRG meetings, Draft Plan consultation, meetings with stakeholders, customer workshops and government agencies has been captured and used to shape and refine our Final Plan.

A high level summary of how we have responded to customer and stakeholder feedback in this Final Plan is included in Table 5.1.

A complete set of customer and stakeholder feedback in the engagement program is provided in Attachment 5.2.

Each chapter of this Final Plan also includes a section on customer and stakeholder engagement. Feedback tables in each chapter show how we have listened and responded to all feedback received.

Final Plan outcomes are also included in tables to demonstrate how engagement has shaped our proposals, and are illustrated as follows:

	Positive/Green – we have customer/stakeholder support for our proposal
	Neutral/Orange – we do not have full support of all customers/ stakeholders
	Negative/Red – we do not have customer/ stakeholder support for our proposal

All customer and stakeholder engagement resources relating to this Final Plan are publicly available on our online engagement platform, Gas Matters at gasmatters.agig.com.au

Resources include

- ✓ AGN Draft Engagement Strategy
- ✓ AGN Draft Plan
- ✓ AGN Draft Plan submissions
- ✓ Stage 1 and 2 Engagement Reports
- ✓ Co-design workshop Final Report, KPMG
- ✓ Customer Engagement Report, KPMG
- ✓ Stakeholder Engagement Report (Draft Plan consultation workshops), KPMG
- ✓ All agendas, presentations and minutes from stakeholders meetings
- ✓ Customer workshop supporting materials
- ✓ Explainer video: How prices are set
- ✓ Video: Customer workshops in action

Table 5.1: Summary customer and stakeholder feedback - Final Plan

How we have responded to customer and stakeholder feedback - Final Plan outcomes	Ref
Services	
✓ Stakeholders support our proposal to maintain the current set of reference and non-reference services in the next AA period, consistent with our Reference Services Proposal approved by the AER in November 2019.	Chapter 6 Table 6.1.
Operating Expenditure	
✓ Customers and stakeholders support our approach and proposed levels of operating expenditure. ✓ Our proposal delivers against customer expectations that current levels of reliability, safety and customer services are maintained, with the inclusion of improved digital service channels. ✓ We have applied a productivity factor to our opex forecast in response to CCP24 feedback. ✓ Customers and stakeholders support our proposal to invest in a Vulnerable Customer Assistance Program and are keen to continue engaging with us to refine and implement our program. Stakeholders noted the importance of this program in light of the potential social and economic impacts of COVID-19. ✓ Environmental sustainability is a high priority for customers and stakeholders, and they support our proposal to replace UAFG with renewable gas.	Chapter 7 Table 7.2, Table 7.3, Table 7.4
• We received mixed levels of support from customers and stakeholders for investment in a community education centre and have not included this initiative as part of this Final Plan. Customers and stakeholders support our continued focus on community education as part of business as usual.	Att 5.2
Capital Expenditure	
✓ Customers and stakeholders support our approach and proposed levels of capital expenditure. ✓ Our proposal delivers against customer expectations that current levels of reliability and safety are maintained. Customers and stakeholders welcomed the proposed completion of the cast iron mains replacement program and the safety and operational benefits (e.g. hydrogen ready) this will deliver.	Chapter 8 Table 8.2
Capital Base	
✓ With the support of stakeholders we are not at this stage proposing substantive changes to the economic lives of our assets in response to the low carbon energy transition. While there are risks that need to be addressed over time our assessment suggests it is better to wait until the subsequent AA period before acting. ✓ We have applied the same approach as approved by the AER for our Victorian and Albury network whereby mains that have been replaced are depreciated from the asset base by the end of the next AA Period. ✓ Stakeholders support our proposed approach to depreciation, to review asset lives in the subsequent AA period and remove replaced mains while delivering a price cut.	Chapter 9 Table 9.1
Financing Costs	
✓ We have applied the AER's Rate of Return Instrument in this Final Plan, and this approach is supported by customers and stakeholders. The rate of return applied in this Final Plan is 4.40%.	Chapter 10 Table 10.1
Incentives	
✓ We are proposing the continuation of the opex incentive mechanism (EBSS) that currently applies for our South Australian network, as well as a new capex incentive mechanism (CESS) consistent with that approved by the AER for our Victorian gas network. ✓ Stakeholders and customers (8 out of 10) strongly support investment in an innovation incentive scheme. The design of the scheme will be developed through ongoing engagement with stakeholders.	Chapter 11 Table 11.1
Demand	
✓ We have applied demand forecasting methodologies accepted by the AER for our most recent South Australian and Victorian reviews and this is supported by stakeholders. ✓ We have updated the growth in the number of residential customers to reflect the Housing Industry Association's (HIA) most recent projection of housing starts, including the HIA's view of the impact of COVID-19 on housing starts, which stakeholders were keen to ensure we considered.	Chapter 12 Table 12.1
Revenue and Pricing	
✓ We are proposing an upfront price cut of 7% (after inflation) which builds on price cuts of 21% delivered at the beginning of the current period. ✓ Customers and stakeholders support our proposed price path and revenue.	Chapter 13 Table 13.1
Network	
✓ We have continued engaging with stakeholders on standardising our terms and conditions for our networks across Australia.	Chapter 14 Table 14.1

5.2 Our Stakeholders

We have identified a number of stakeholder groups with an interest in how we plan, manage and operate our South Australian gas distribution network.

In Stage 1 we released our Draft Engagement Report for consultation with key stakeholders and sought feedback to ensure we are engaging with all relevant stakeholders.

Our SARG and our RRG represent a cross-section of our customers, energy retailers, government agencies and other businesses in the gas supply chain.

Our key stakeholder groups are illustrated in Figure 5.3.

Figure 5.3: Our Stakeholders

5.3 Our Engagement Principles and Approach

Our objective is to develop a Final Plan which delivers for current and future customers, is underpinned by effective stakeholder engagement and is capable of being accepted by our customers and stakeholders.

We have adopted a series of engagement principles as shown in Figure 5.4. These principles guide how we engage with our customers and stakeholders. As part of Stage 1 engagement we consulted on these principles, and they were endorsed by all stakeholders.

In designing our engagement strategy and approach for this Final Plan we considered our recent Victorian and Albury 2018 – 2022 AA review and sought further views of our stakeholders.

Our approach for this engagement program was to:

- ✓ continue with our four staged approach, which was considered a solid foundation by our stakeholders;
- ✓ seek opportunities to further collaborate with customers where there was an opportunity to co-design;
- ✓ deliver a new online engagement platform to support our face to face engagement activities;
- ✓ engage more broadly with diverse segments of the community (e.g. CALD); and
- ✓ allow for more iteration of our plans to be developed over time with customers

As part of our engagement strategy we set KPIs. Our performance against these KPIs is illustrated in Table 5.2.

Figure 5.4: Our Engagement Principles

Genuine and committed

We listen and respond to the needs of our customers and stakeholders, driving a culture of delivering value for our customers.

- Engagement is led from the top
- Stakeholder engagement is embedded in our business planning
- We are always looking for ways to improve

Clear, accurate and timely communication

We provide information that is clear, accurate, relevant and timely.

- Online and print fact sheets
- Briefings and information forums
- Publication of the Draft Plan

Accessible and inclusive

We involve customers and stakeholders on an ongoing basis in a meaningful way, to ensure that our plans deliver for our customers.

- Stakeholder meetings
- Roundtables and workshops
- Customer forums and information sessions
- Online engagement

Transparent

We clearly identify and explain the role of customers and stakeholders in the engagement process, and consult with customers and stakeholders on information and feedback processes.

- Publication and consultation of our proposed engagement approach
- Online public reporting
- We publish and consult on our reports
- We clearly report how we used customer and stakeholder insights to inform our plans

Measurable

We measure the success, or otherwise, of our engagement activities.

- Seek stakeholder feedback at all key stages of our engagement
- Report on feedback
- Identify ways we can improve our approach

Table 5.2 Our Performance against Engagement KPIs

Theme	Key Performance Indicators	Our Performance
Clear, accurate and timely communication	• Educational materials used during customer workshops • The process for engagement (how clearly materials were presented) • Measured by a 70% or above satisfaction score,	✓ 73% of customers were very satisfied with the education materials provided during customer workshops. A further 22% were satisfied with the materials. ✓ 98% of customers very satisfied/satisfied that there were opportunities to have a say. ✓ 73% of customers were very satisfied and a further 26% were satisfied with the presentations and facilitators. ✓ 67% of stakeholders were highly satisfied and 33% were satisfied the meeting and workshop materials were useful and clearly presented and meetings were well organised. ✓ 55% of stakeholders highly satisfied the topics presented were relevant and appropriate for the SA network. 45% were satisfied.
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 • Customer satisfaction of the overall engagement process, as measured by 70% or above score on workshop feedback	✓ The stakeholder map was developed in consultation with SARG and RRG members. ✓ Overall, 99% very satisfied/satisfied with the customer workshops. ✓ 73% of stakeholders were highly satisfied and 27% were satisfied that the engagement process was inclusive. ✓ 73% of stakeholders were highly satisfied that our reference groups and workshops provided a useful format to engage with AGN. 27% were satisfied. ✓ 100% of stakeholders were satisfied with our engagement program, with 64% of stakeholders highly satisfied. ✓ 90% of stakeholders rated our engagement program as a high standard.
Our engagement activities	• Public disclosure of details about engagement activities on website • Attendance by CEO at one or more workshops • Publish Draft Plan, open for stakeholder comment	✓ All engagement resources and materials available on Gas Matters. ✓ 90% CEO and 100% executive attendance at SARG and RRG Meetings. ✓ More than 55% CEO attendance and 100% executive attendance at customer workshops. ✓ Draft Plan open for six week consultation period. ✓ 73% of stakeholders were highly satisfied AGN delivered a 'no-surprises' engagement approach. A further 27% were satisfied. ✓ 91% of stakeholders were highly satisfied our engagement process was transparent. ✓ 70% of stakeholders were highly satisfied there were opportunities to ask questions and seek further information and that feedback was well responded to. 30% were satisfied.

*Customer Workshop Feedback forms (March 2020)
**Stakeholder Feedback survey (June 2019)

Our staff were actively involved in our customer and stakeholder engagement program.

Throughout the program engagement has been led from the top, with Chief Executive Officer attendance at 90% of all stakeholder meetings and more than half the customer workshops.

"Good representation of management, it always feels that we're a part of change"

All customer engagement sessions were attended by at least one executive team member and around 20 AGN staff actively participated in the sessions.

High levels of staff involvement allowed customers to interact with subject matter experts, and allowing staff to learn directlty from customers and their experiences.

"The conduct of AGN staff – they took things seriously, listened and tried to understand, they were respectful"

We received positive feedback about our engagement program and process from customers who attended our workshops.

"Everything explained in detail so you know you're not missing any information"

We also received positive feedback from our stakeholders in relation to the quality of our materials, how we ran our engagement activities and that we responded to all feedback we received.

"In general, AGIG did a good job in its engagement process – giving stakeholders ample opportunity to discuss any issues etc." (Business SA)

"We have been happy with the process and there have been no surprises" (Property Council of South Australia)

"The best engagement process in thirty years as either an individual or representing a group I have ever had the pleasure to attending. Excellent presentation, well run, best organised and very inclusive to all members involved in the engagement process."(SAFRRA Inc).

Further feedback about our engagement program can be found in Attachment 5.3.

5.4 Strategy & Research

The aim of Stage 1 was to better understand customer and stakeholder needs and expectations. It included consultation on our proposed engagement strategy.

This is an important step in our four staged approach to ensure we were engaging with the relevant key stakeholders and they were comfortable with proposed engagement activities.

We sought to understand what is important to our customers and stakeholders – and what topics they wanted to be engaged on.

In May 2019, we held one-on-one consultation meetings with 15 SARG members and two government agencies to discuss our proposed approach and explore key issues.

During stakeholder meetings we facilitated discussion around three consultation questions:

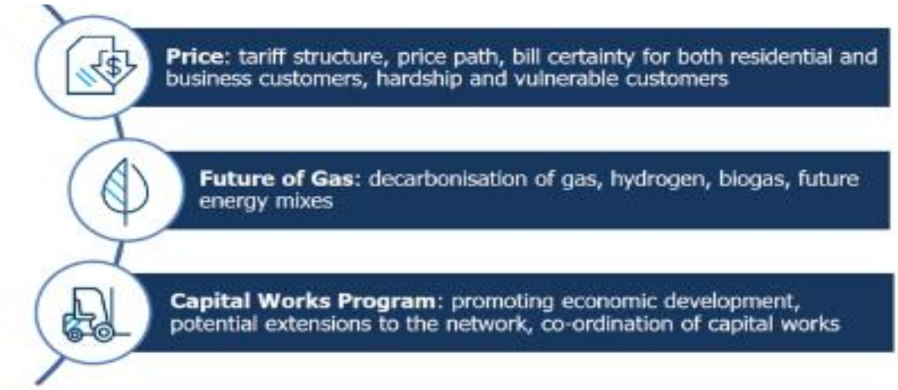
- *What are the most important aspects of our services?*
- *What issues should we be considering in our future planning for the pipeline?*
- *What aspects of our future plans would you like to engage on?*

As shown in Figure 5.5 the key areas of interest were price, future of gas and our capital works program.

Stakeholders told us that the cost of utilities (broadly) and affordability are important issues for business and residential customers and that they sought price certainty.

Many stakeholders noted the rapid changes taking place in the energy industry, and were interested in the future of gas and potential opportunities for renewable gas,

Figure 5.5: Key Issues of Importance for Stakeholders



including hydrogen blended into the gas distribution network.

Stakeholders place value on reliability and maintaining current service levels and noted that for many customers gas is a critical input into their business operations.

Other topics of interest included our capital program and opportunities to raise community awareness of the gas supply chain.

We also sought feedback on our proposed engagement strategy, including our proposed approach to stakeholder engagement, identification of key stakeholders, proposed engagement activities and the timeline.

Feedback from stakeholders was used to inform our final engagement strategy – ensuring our activities were appropriate and allowed for meaningful engagement.

Upon concluding Stage 1 we released a report summarising customer and stakeholder feedback, and our final engagement strategy.

A copy of our Stage 1 Stakeholder Engagement Report is provded in Attachment 5.1

A summary table of all feedback and how we responded in Stage 1 is illustrated in Table 5.3.

Table 5.3: Stage 1 Stakeholder Feedback

Topic	Stakeholder feedback	Our response
Our approach and principles	• Stakeholders noted Stage 1 engagement activities were important to clearly define our customers and stakeholders, the broad areas for engagement and timing. • Stakeholders supported the Energy Charter, our principles of engagement, our 'no surprises' approach and our focus on our customers. • Reference Group Members mentioned the high quality of meeting materials and presenters. The information was well structured and the objectives clear. • Stakeholders supported our staged approach to developing our plans, particularly the release of and engagement on our Draft Plan. • Transparency and accessibility was highlighted by stakeholders as critical as we develop our plans • Reference Group Members were keen to ensure the agenda and objectives of each meeting were clear • Reference Group Members may consider opportunities to co-share responsibilities and attendance depending on agenda items. • Stakeholders indicated they would like to maintain the relationship with AGN post engagement around future planning.	• We confirmed our four stage approach to develop our Final Plan. • We confirmed our commitment to our engagement principles and 'no surprises' approach. • We committed to ensuring a strong customer focus, including clearly explaining how our plans are in the long-term interests of our customers. • We committed to continue to engage with our stakeholders and SA Reference Group members on key issues as part of our business as usual activities.
Our stakeholders	• Stakeholders were of the view the SARG and RRG comprises a broad spread and cross-section of the community. • Stakeholders noted environmental representation should be considered. • Stakeholders were positive that senior levels of AGN staff were present at the meetings. • Stakeholders expressed interest that the stakeholder map identified the broader community as a stakeholder	• We considered opportunities to engage environmental representation. • We revised our stakeholder map.
Our activities	• In relation to SA Reference Group meetings, stakeholders suggested that: meeting objectives be clear and agendas sent promptly, we consider having separate business and residential meetings (for specific issues), and that there could be benefit in members meeting together • Members are of the view the quality of meeting materials is satisfactory • Members may look to co-share meeting responsibilities depending on agenda items • All stakeholders supported engagement with customers • Stakeholders were keen to ensure that customer engagement activities were representative of the community • Members supported the ongoing Reference Group meetings as an efficient way to receive input into the development of our plans • Stakeholders value regular one-on-one meetings to discuss specific issues in detail • Digital updates and factsheets were considered useful • Some stakeholders expressed interest in working closely with AGN on identifying issues of importance and co-designing solutions	• We committed to issuing meeting agendas and materials in a timely way. • Where appropriate, we agreed to facilitate separate Reference Group sessions for residential and business customers. • We invited retailers to meet with SARG members where appropriate. • We documented and reported on our customer engagement activities. • We sought ongoing advice from Members on ensuring representation of the community, and the development of materials
Our timeline	• Customers and stakeholders supported our timeline.	• We confirmed the timeline for developing our plans.

5.5 Developing our plans

We delivered a series of engagement activities to inform the development of the Draft Plan, consultation on our Draft Plan, and refinement of our plans to form our Final Plan.

These activities included three phases of iterative customer workshops, regular SARG and RRG meetings and workshops, and a dedicated co-design workshop with stakeholders.

This section covers each of these engagement activities, customer level feedback and how this feedback has shaped our Final Plan.

5.5.1 Customer Engagement

We engaged with a diverse group of customers through a series of iterative workshops to inform and shape this Final Plan.

Our customer engagement workshops were run in three phases with the same groups of customers, allowing iterative engagement as our plans developed.

The first two phases of workshops led to the development of our Draft Plan, with a third phase of workshops held as part of Draft Plan consultation.

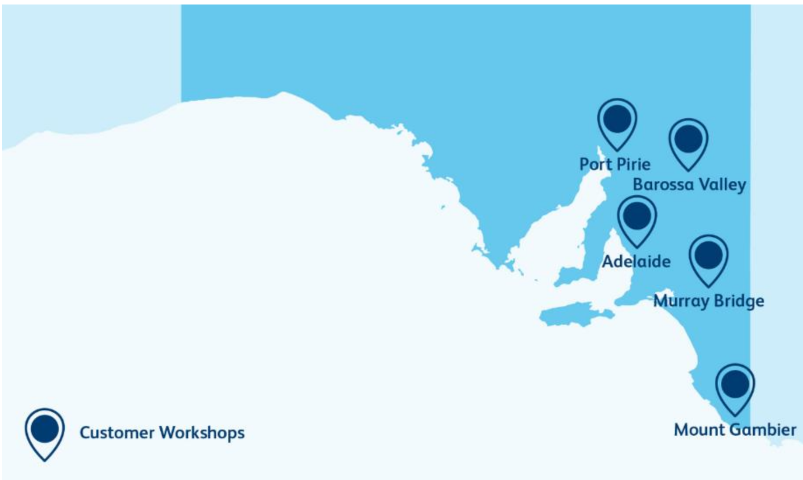
We engaged KPMG to facilitate and document our customer engagement activities. A full report is included in attachment 5.3.

Workshop Design and Participation

Three phases of workshops were held in five locations across South Australia with a total of 319 participants across 22 workshops.

Customer attendance at each workshop is shown in Table 5.4. Workshop were well attended with

Figure 5.6: Customer workshop locations



a return rate in Phase 2 workshops of 77% and 67% in Phase 3.

Participants were recruited through a specialist third party provider and represented a broad cross section of the community.

To ensure we understood the needs and preferences of diverse customer segments, we held dedicated workshops for residential, business, metropolitan, regional and culturally and linguistically diverse (CALD) customers.

We partnered with the Multicultural Communities Council of South Australia (MCCSA) to hold workshops with customers from CALD communities.

MCCSA invited community leaders as participants from cultural groups including Bhutanese, Chinese, Eritrean, Fijian, Filipino, Fullah, Indian, Ivorian, Serbian, Sierra

Table 5.4: Customer Workshop Attendance

Location	Customer Segment	Phase 1	Phase 2	Phase 3
Adelaide	Residential customers	20	15	10
Adelaide	Business customers	19	17	16
Adelaide	CALD customers	21	16	11
Port Pirie	Residential and business customers	16	14	13
Barossa	Residential and business customers	17	11	12
Murray Bridge	CALD customers	10	6	5
Mt Gambier	Residential and business customers	25	22	21
	TOTAL	**128**	**101**	**88**

Leonean, Somalian and Spanish. Traditional Aboriginal land owners were also represented at the workshops held in Murray Bridge.

Phase 1 Customer Workshops: Objectives, Engagement Activities and Results

The objectives of Phase 1 customer workshops were to:

- ✓ understand customer values, service expectations and priorities to inform future investment plans;
- ✓ engage with, and listen to customers to understand issues of importance; and
- ✓ educate customers about AGN and its role, to facilitate ongoing engagement at phase 2 and 3 workshops.

Phase 1 workshops were 90 minutes in duration with participants working in groups at tables. AGN presenters and subject matter experts were available to respond to questions.

We asked customers a series of questions relating to reliability, public safety, customer service, affordability, the gas network and sustainability.

Key topics, information presented and insights from Phase 1 are illustrated in Table 5.5.

In Phase 1 customers told us that their top priorities are price/ affordability, reliability of supply, maintaining public safety, and the future of gas in a low carbon economy.

While the current price of gas does not appear to be of major concern, price and affordability is the top priority for customers in managing utility bills for their homes and businesses.

"With a young family, my first priority is always affordability"

Customers told us they highly value an uninterrupted supply of gas in their homes and business and are satisfied with current levels of reliability.

Customers told us it was important to receive timely customer service by knowledgeable staff who demonstrate empathy and understanding in responding to queries or resolving issues.

In terms of customer service, customers were satisfied with current service levels, with preferences for interacting with AGN through a broader variety of channels (e.g. website, email, web chat).

Sustainability was a key area of interest for customers. Customers were more aware of opportunities to lower carbon emissions from electricity and were very keen to understand innovation in gas and how AGN could play a role in decarbonisation.

"Reliability is critical…. public safety is assumed…need to innovate and reduce carbon footprint"

Phase 2 Customer Workshops: Objectives, engagement activities and results

In Phase 2 workshops we looked to further explore issues of importance, and gain customer input into the development of our plans.

The objectives of our Phase 2 workshops were to:

- ✓ validate customer feedback from Phase 1;
- ✓ share information about AGN's activities;
- ✓ explain how prices are set;
- ✓ explore issues of importance to AGN and customers; and
- ✓ test and seek feedback on costed proposals.

Phase 2 workshops were 2.5 hours in duration and included opportunities for table discussion as well as digital voting. Participants were invited to vote and rank initiatives they were supportive of, using an online voting tool.

In Phase 2 we presented an early price forecast to reduce prices by an indicative 6% after inflation. In this context we presented our proposed approach for investment in reliability, safety and customer

service. We explored areas for further development as identified by customers including digital customer service, sustainability and innovation. We also provided information in relation to the growth of our network.

Key topics, information presented and insights from Phase 2 workshops are provided in Table 5.5.

In our Phase 2 workshops customers told us they value our track record of performance in relation to safety and reliability, and expect this to continue. In all workshops there was a high level of customer support for our proposed approach to invest in our capital programs to maintain current safety and reliability service levels.

"I can see that there are some good measures to maintain the network reliability being taken"

We presented contextual information about natural gas and greenhouse gas emissions to enable further discussion around sustainability and the future of gas. Customers told us that lowering carbon emissions is very important to them, with 51% of customers rating it as extremely important.

"Climate change needs to be addressed by all businesses but most importantly by a large network"

Customers expect us to pursue more opportunities to lower emissions. Customers supported AGN presenting additional proposals to lower emissions along with the resultant bill impacts in our Draft Plan and Phase 3 workshops.

Customers told us they see value and are willing to accept a small price increase to enable AGN to invest in innovation projects.

"I am happy to support innovation projects because it may be of benefit to the consumer or the environment in the future"

In response to customer feedback in Phase 1, we explored opportunities with customers to introduce more digital customer services such as SMS notifications, inline services and email. Customers told us they expect that digital communication channels will be increasingly available, but are sensitive to price. Feedback was that online services are considered a preferred investment over SMS communications.

Phase 3 Customer Workshops: Objectives, engagement activities and results

The objectives of our Phase 3 workshops were to:

- ✓ validate customer feedback from Phase 2;
- ✓ seek further feedback on priorities for investment in digital services;
- ✓ share AGN's Draft Plan and investment proposals for consultation;
- ✓ test and seek feedback on costed proposals for inclusion in our Final Plan

Phase 3 workshops were 2 hours in duration and included opportunities for table discussion as well as digital voting.

In Phase 3 we presented our Draft Plan for consultation. We presented an outline of our Draft Plan and showcased the key initiatives in poster format, allowing customers to view our plans and ask questions.

Participants were invited to vote on their support for the Draft Plan. 96% of customers said they supported our proposals.

"The Draft Plan looks good, you have been able to provide clarity and questions well answered"

In providing support for the Draft Plan, customers noted the importance of continued performance levels around safety, reliability and customer service.

It was also considered very important that the Draft Plan has a future focus on the environment and emissions in particular.

"Good to know that gas will be around for many years to come and it is being looked after"

Participants were invited to provide further feedback, and vote on additional investment proposals (with bill impacts provided) which AGN could include in its Final Plan subject to customer and stakeholder support:

- replacing lost gas (i.e. UAFG) with renewable gas;
- access to an innovation allowance;
- a community education centre; and
- a vulnerable customer assistance program.

Customers were very supportive of investing in renewable gas to replace / offset lost gas, and considered this to be good value for money at an annual bill impact of ($1.50 - $5.50). Consistent with Phase 1 and 2 workshops, customers considered reducing emissions as very important for future customers.

"Small cost to us, quite a significant impact on environment, economy, etc."

Almost 8 out of 10 customers were either supportive or strongly supportive of investment in innovation between $500,000 to $1m per annum. Customers cited the importance of finding better, more effective and efficient ways of working.

"Always good to be innovative and a leader in South Australia"

We presented a proposal to invest in a community education centre with a range of supporting education programs including digital resources, regional outreach

program and school education programs. An annual bill impact of $1.50 was presented.

While recognising the importance of education, customers were concerned with accessibility and value for all South Australians. Customers provided feedback that AGN need to consider alternative models for service delivery and funding (e.g. joint initiatives with others).

"Good idea for schools – may be better and cheaper to go to schools rather than have a dedicated centre. A website would be better"

Following on feedback from workshop phases 1 and 2, we presented a proposal to introduce a dedicated program to assist vulnerable customers at an annual bill impact of $1 – 2.

75% of customers were ether supportive or strongly supportive of the proposed investment, and that it was considered 'the right thing to do'. Customers considered investment as responsible business and worthwhile for community support to those who are in financial distress and older Australians.

"We should help those who can't help themselves"

Customers were keen to ensure the program was accessible in its design, and that the delivery model is fair and equitable.

Customer Workshops: Summary Results

A summary of customer workshop results and insights is show in Table 5.5 arranged by the topics as discussed:

- price and affordability;
- public safety and reliability;
- customer experience; and
- sustainability and innovation

Customer feedback and how we have responded is included in the relevant Chapters to show how we have responded throughout our Final Plan.

A complete set of customer and stakeholder feedback is included in Attachment 5.2.

Table 5.5 Customer Engagement Activities and Results by Topic

Topic	Engagement Activity	Key Insights and Results
Price & Affordability	**Phase 1 Customer Workshops**	
	• We provided an overview of the residential and business customer billing process and the composition of residential/business gas bills. • Engagement Activity: - *What does affordability mean to you?*	✓ While the current price of gas does not appear to be a major concern, price and affordability are the top priorities for customers. ✓ Participants told us affordability means fair and transparent prices, manageable prices and forward visibility to avoid 'bill shock'.
	Phase 2 Customer Workshops	
	• We presented on how we set prices and our forecast price reduction. We discussed how gas distribution prices are set in the context of a regulatory framework. • Engagement Activity: - *Participants were invited to ask questions and participate in group discussion*	✓ Customers were interested in understanding how price reductions are passed through to consumers.
	Phase 3 Customer Workshops	
	• We presented our forecast 6% price cut (after inflation) in year 1, followed by increases of 1.2% per year from 1 July 2021. • Engagement Activity: - *Do you have any questions or feedback about AGN's proposed price cut?* - *To what degree do you support an initiative for AGN to have a vulnerable customer assistance package*	✓ Customers were particularly supportive of the proposed price cut, and were pleased to see that their feedback had been considered in AGN's proposals. ✓ Customers support AGN's Draft Plan, with 96% reporting either strong support or support. ✓ 75% of participants were either supportive or strongly supportive of AGN investing in a vulnerable customer assistance program.

Topic	Engagement Activity	Key Insights and Results
Public Safety & Reliability	**Phase 1 Customer Workshops**	
	• We provided an overview of our role in the gas supply chain, our vision and values, and the context of regulation and business planning. • Engagement Activity - *What does reliability mean for you in your home/business?* - *How satisfied are you with the reliability of your gas supply?*	✓ Customers expect AGN to deliver a high level of public safety and feel that safety is well managed. ✓ 31% of participants ranked public safety as most important. ✓ 42% of participants ranked public safety as their first or second priority. ✓ Customers highly value an uninterrupted supply of gas in their homes and business and are satisfied with current service levels. ✓ 52% of participants ranked reliability first or second priority. ✓ Customers are satisfied or very satisfied with their current levels of reliability.
	Phase 2 Customer Workshops	
	• We presented on the approach we propose to take to maintain current levels of public safety and reliability, including our current reliability performance, network design, our control systems, maintaining security of supply in outages and mains integrity/protection. • Engagement Activity: - *I am comfortable with the proposed approach to maintain current levels of public safety (yes, no, need more information)* - *I am comfortable with the proposed approach to maintain current levels of reliability (yes, no, need more information). Why?*	✓ 92% support for our approach to maintaining current levels of public safety. ✓ 96% support for our proposed approach to maintaining current levels of reliability.
	Phase 3 Customer Workshops	
	• We presented on our capital expenditure, including our mains replacement program, proposed project investments, and our performance to date and our proposed approach to maintaining high levels of community safety and reliability • Engagement Activity: - *Do you have any feedback or questions about how public safety levels will be maintained in our Draft Plan?* - *Do you have any feedback or questions about how reliability levels will be maintained in AGN's Draft Plan?*	✓ Customers trust AGN's track record in delivering high levels of safety and reliability, and are satisfied with the proposed approach to maintain current levels. ✓ Customers support AGN's Draft Plan, with 96% reporting either strong support or support.

Topic	Engagement Activity	Key Insights and Results
Customer Experience	**Phase 1 Customer Workshops**	
	• We provided an overview of our role in the gas supply chain, and discussed examples of when customers interact with us. We presented our proposal to make smart meters available at a fee for service and we presented information on where network growth was planned in each of the local areas. • Engagement Activity: - *What do you expect from a great interaction with AGN?* - *Participants were asked to complete a communications preference worksheet to indicate their preferred methods of communicating with us* - *We asked if we should be doing something different when it comes to meters and meter reading*	✓ Customers would like to interact with AGN through a variety of channels. The most preferred channels for interacting were via phone, email, website and SMS/text. Customers have a strong preference to report a gas leak by phone. ✓ Customers expect timely customer service by knowledgeable staff who demonstrate empathy and understanding in responding to queries or resolving issues. ✓ Many customers are satisfied with current meter reading practices, with some customers interested in smart meters and access to real-time data on gas usage.
	Phase 2 Customer Workshops	
	• We presented on our customer satisfaction results and our proposed approach to maintain current levels of customer service and communication channels. We presented our proposal to make smart meters available as a choice for customers at a fee for service. • Engagement Activity: - *I expect AGN to deliver more of its services using digital channels between now and 2026. Why?* - *I am prepared to pay $2.50 on my bill per annum so that AGN can invest in improved online services. Why?* - *I am prepared to pay $5.50 on my bill per annum so that AGN can invest in SMS communications. Why?*	✓ Customers expect that digital communication channels will be increasingly available but are sensitive to price. ✓ Customers consider online services to be a better investment than the more expensive option of SMS communications. ✓ 80% of participants expect/strongly expect AGN to deliver more services using digital channels between now and 2026. ✓ 54% agreed with paying $2.50 on their bill so AGN can invest in improved online services. ✓ 63% disagreed with paying $5.50 on their bill per annum so that AGN can invest in SMS communications.
	Phase 3 Customer Workshops	
	• We presented our revised proposal to improve the digital customer experience with a focus on the AGN website. • Engagement Activity: - *Customers were invited to share views on the importance of various types of digital functionality, such as digital self-serve options and notifications.*	✓ Customers support AGN's proposal to invest in digital communication and customer services in a cost effective way, with varying individual preferences for specific functionality.

Topic	Engagement Activity	Key Insights and Results
Sustainability & Innovation	**Phase 1 Customer Workshops**	
	• We provided an overview of our path to decarbonise gas through hydrogen and bio methane. • Engagement Activity: - *Prioritisation activity*	✓ Customers are interested in environmental considerations and AGN's role in driving sustainable energy solutions in the future. ✓ 25% of participants ranked 'Innovation and the future of gas' as their first or second priority.
	Phase 2 Customer Workshops	
	• We presented information about renewable gas and our role in considering ways to lower carbon emissions. We shared information on our current activities including how we are preparing our network for sustainable gas and our pilot project blending hydrogen into the existing natural gas network. • Engagement Activity: - *How important is it to you that we consider ways to lower carbon emissions?* - *I would like AGN to pursue more opportunities to lower carbon emissions further?* - *I am prepared to pay more on my bill every year so that AGN can invest in innovation projects that benefit the energy industry. Why?*	✓ Customers expect AGN to pursue more opportunities to lower emissions further in addition to existing plans. ✓ 87% felt that lowering emissions is very/extremely important. ✓ 87% of participants indicated they are willing to accept a small price increase to enable AGN to invest in innovation projects. 54% indicated they would be prepared to pay a price of $2 per annum for this innovation fund.
	Phase 3 Customer Workshops	

	• We presented on our initial investments that help secure a low carbon future for our customers, including Hydrogen Park SA
	• We presented our proposal to have access to more than $500k - $1 million per annum to fund innovative projects - where we are able to demonstrate that the project has the potential to improve customer service, efficiency or sustainability including:
	  • New technology testing such as micro cameras in pipes
	  • Trials to test blending more renewable gases in the network
	• Engagement Activity:
	- *To what degree do you support:*
	- *the initiative to replace lost gas (UAFG) with renewable gas*
	- *AGN having access to an innovation fund (innovation Allowance) to invest in innovation projects at $1-$2 per annum on the average bill*
		✓ Customers consider lowering emissions to be a high priority and there are high levels of support for AGN replacing lost gas (UAFG) with renewable gas.
		✓ Customers support AGN replacing lost gas with renewable gas, with 84% of respondents either supportive or strongly supportive. A further 10% were moderately supportive.
		✓ Almost 8 in 10 customers are either supportive or strongly supportive of AGN investing in innovation.

5.5.2 Co-Design Workshops

We ran a series of co-design workshops as part of our engagement program to understand how we can better support vulnerable customers.

The co-design process was facilitated by KPMG, and brought together experts from the social service sector. Co-design is a process by which organisations collaborate with stakeholders and customers to inform decision making. A full report on the Co-design workshops and results is provided in Attachment 5.4.

Three rounds of workshops were held where participants contributed to developing an understanding of who our vulnerable customers are and generating ideas for supporting vulnerable customers for consideration by AGN.

Participating organisations included the Financial Counsellors Association of SA; Energy and Water Ombudsman SA; City of Playford; National Disability Services; Anglicare SA; Uniting Communities; Council of the Ageing SA; Origin Energy; and Multicultural Communities Council of SA.

The following key themes emerged as priorities from the co-design process for AGN to consider:

- understanding customers better through customer relationship management, priority services and empathy in service delivery;
- doing more in the community through engagement outreach and education programs;
- being proactive in situations when customers are vulnerable;
- being present in the affordability debate; and
- ensuring clear accountability for vulnerable customers within AGN.

Following the co-design workshops, we developed a proposal for a Vulnerable Customer Assistance Program which we tested with customers and stakeholders during draft plan consultation. We gained strong support for this initiative and it is included in Chapter 7 of this Final Plan.

5.5.3 Stakeholder Engagement

Our Stakeholder Reference Groups

We engaged with our Stakeholder Reference Groups as a key way to receive input from stakeholders on our plans as they have been developed.

Membership of our SARG reflects the diversity of our customer base, with organisations representing residential customers, vulnerable customers, older Australians, multicultural communities, business and industrial customers, builders and developers, and local government.

The RRG comprises representatives from gas retailers who operate in national markets which we serve, including South Australia.

Seven meetings of the SARG, and five meetings of the RRG were held as part of developing our Final Plan.

Meeting topics and materials were presented based on issues of importance and key components of this Final Plan.

We also regularly sought feedback on our customer engagement activities and results from our workshops. We welcomed stakeholder attendance at our customer workshops and some SARG members observed the sessions, which was valuable to our process.

Throughout the development of our plans, our stakeholders were keen to understand our future plans in the context of price, and importantly that our proposals are cost efficient whilst delivering value for customers.

A summary of key topics and information presented in the development of the Draft Plan is summarised in Table 5.6 and Table 5.7.

Following the publication of our Draft Plan we held combined SARG and RRG workshops to refine our Final Plan. A summary of topics and information presented at combined meetings is show in Table 5.8.

Stakeholder Reference Group Membership

South Australian Stakeholder Reference Group

- Australian Industry Group (SA)
- South Australian Council of Social Service
- Multicultural Communities Council of SA
- Financial Counsellors of South Australia
- Urban Development Industry Australia (SA)
- Property Council of Australia (SA)
- Federation of Residents and Ratepayers Association Inc.
- Business SA
- Consumers SA
- Council for the Ageing (SA)
- Local Government Association (SA)

Retailer Reference Group

Our retailer reference groups includes representatives from the major retailers including AGL, Lumo/ Red Energy, Alinta Energy, Energy Australia, Origin Energy, Savant Energy Power, Simply Energy

Table 5.6: South Australian Reference Group (SARG) Meeting Topics and Information/ Discussion

Meeting #	Key Topics	Information Presented/ Key Areas of Discussion
Meeting #1 (Apr 2019)	Our business Developing our future plans Our draft engagement plan Reference services	• Our vision and values, and performance levels • Role of the SA Reference Group and introduction • Overview of the regulatory framework • Our stakeholder engagement approach • Overview of proposed reference services
Meeting #2 (Jun 2019)	Final engagement plan Developing our future plans Pipeline and reference services	• Stakeholder insights/feedback from our engagement • Our pipeline and reference services proposal
Information Session (July 2019)	Hydrogen	• COP21 emission targets • Hydrogen as a future fuel • Key projects in Australia • Australia's Hydrogen Strategy • Projects around the world • Hydrogen and the transport sector • Hydrogen Park SA
Meeting #3 (Aug 2019)	Stage 1 Engagement Report Our capex proposal Future of gas and hydrogen Pipeline and reference services	• Customer growth and satisfaction results • Our Stage 1 Stakeholder Engagement Report • Overview of Phase 1 customer workshops and co-design • Capital works program, operating context and approach • Future vision for gas networks and innovation • Submission of the Reference Services Proposal
Meeting #4 (Aug 2019)	Early price modelling Phase 1 customer workshops Regulatory building blocks	• Early price modelling • Results from Phase 1 customer workshops • Building blocks overview – how prices are determined
Meeting #5 (Oct 2019)	Updated price modelling Phase 2 customer workshops Co-design: Vulnerable Customers Capex and opex proposals	• Our Energy Charter Disclosure Report • Early price forecast • Approach to Phase 2 customer workshops • Our online engagement portal, Gas Matters • Our co-design process supporting vulnerable customers • Our preliminary expenditure proposals
Meeting #6 (Dec 2019)	Rate of Return Capital Base Incentives Demand	• Updated price forecast • Observations from our co-design process • Results of our Phase 2 workshops • Regulatory modelling update
Meeting # 7 (Feb 2020)	Draft Plan overview Customer and Stakeholder Engagement	• Price update • What we will deliver • Regulatory modelling update • Financing costs • Expenditure proposals • Depreciation • Demand and Incentives • Future of Gas

Table 5.7: Retailer Reference Group (RRG) Meeting Topics and Information/ Discussion

Meeting #	Key Topics	Information Presented/ Key Areas of Discussion
Meeting #1 (Apr 2019)	Our business Developing our future plans Our draft engagement plan Reference services Terms and conditions	• Our vision and values • Role of the Reference Group and issues of importance • Overview of the regulatory framework • Our stakeholder engagement approach • Overview of proposed reference services • Our approach and timeframes for terms and conditions
Meeting #2 (Jul 2019)	Final engagement plan Developing our future plans Pipeline and reference services Draft terms and conditions	• Stakeholder insights/feedback from our engagement • Future of Gas and hydrogen • Our pipeline and reference services proposal • An overview of the draft terms and conditions
Meeting #3 (Nov 2019)	Capex and opex proposals Pipeline and reference services Draft terms and conditions	• Our Stage 1 Stakeholder Engagement Report • Overview of Phase 1 customer workshops and co-design • Capital works program, operating context and approach • Future vision for gas networks and innovation • Submission of the Reference Services Proposal • Feedback on draft terms and conditions
Meeting #4 (Dec 2019)	Phase 2 Customer workshops Regulatory building blocks overview Rate of return Demand forecast Draft terms and conditions	• Early price modelling • Results from Phase 1 customer workshops • Pricing - Regulatory Building blocks overview • Feedback on current draft terms and conditions
Meeting #5 (Feb 2020)	Draft Plan overview Customer and Stakeholder Engagement	• Price update • What we will deliver • Terms and Conditions • Regulatory modelling update • Financing costs • Expenditure proposals • Depreciation • Demand and Incentives • Future of Gas

Table 5.8: Combined SARG & RRG Workshops and Meetings

<table>
<tr><th>Meeting #</th><th>Key Topics</th><th>Summary of Information presented</th></tr>
<tr><td>Deep Dive Workshop #1 (March 2020)</td><td>Operating Expenditure
Capital Expenditure
Future of Gas
Incentives</td><td>• Draft Plan Overview
• An overview of our opex proposals, approach and forecasts including input cost escalation and productivity.
• An overview of our capex proposals, approach and forecasts including mains replacement, safety and reliability, augmentation, growth and customer service.
• An overview of the future of gas and how we are proposing to respond
• Incentives including our approach to including Opex/Capex, customer service and innovation incentives.</td></tr>
<tr><td>Deep Dive Workshop #2 (April 2020)</td><td>Rate of Return
Capital Base
Future of Gas
Demand
Network pricing
Terms and Conditions</td><td>• How the business is responding to COVID-19
• Our approach to Rate of return including return on capital and tax
• Future of Gas including current projects and our proposed approach to considering asset lives
• Capital Base our forecasts including RAB adjustment, asset lives and depreciation
• Demand (residential, commercial and industrial)
• Revenue and Network Prices, including drivers and proposed price path
• Terms and Conditions</td></tr>
<tr><td>Combined SA and Retailer Meeting (May 2020)</td><td>Capex and opex proposals
Pipeline and reference services
Draft terms and conditions</td><td>• Business and COVID Response update
• Draft Plan consultation feedback via customer workshops, co-design workshops, SARG/ RRG feedback, CCP feedback, public submissions
• Our response to feedback across key themes:
- Potential impact of COVID 19
- Price path
- Future of Gas
- Mains replacement
- Productivity
- Input Cost Calculation
- Vulnerable Customer Assistance Program
- UAFG
- Community education
- Innovation allowance
• Terms and Conditions</td></tr>
<tr><td>Combined SA and Retailer Meeting (June 2020)</td><td>Phase 2 Customer workshops
Regulatory building blocks overview
Rate of return
Demand forecast
Draft terms and conditions</td><td>• Early price modelling
• Results from Phase 1 customer workshops
• Pricing - Regulatory Building blocks overview
• Feedback on current draft terms and conditions</td></tr>
</table>

We provided early and ongoing price modelling updates to members at our meetings as part of our 'no surprises' approach to engagement which was welcomed by stakeholders.

We presented our draft expenditure proposals to SARG and RRG members in February 2020. Stakeholders were supportive of our approach and were keen to understand the details and costs as the plans were further developed.

The future of gas was a key topic of discussion and area of interest discussed as the plans were developed.

Stakeholders were keen to ensure this Plan delivers in the long-term interest of customers in light of an increasing focus on energy decarbonisation.

Stakeholders were keen to understand the potential for renewable gases such as hydrogen to become a future fuel, and what the transition roadmap will be. With this in mind, stakeholders expressed a keen desire to understand:

- readiness of the network to take hydrogen and whether there is capital investment required;
- whether future uncertainty would have any impact on asset lives;
- current and potential Government policy changes in relation to emissions reduction;
- the level of investment and success of hydrogen projects across Australia;
- how customers and stakeholders will be engaged on the renewable gas journey;
- potential impact to prices, in this or subsequent regulatory periods.

To support consultation with stakeholders on our Draft Plan we ran two deep-dive workshops combining our SARG and RRG members.

We engaged KPMG to facilitate and document feedback for participants. A copy of the report is included in Attachment 5.6.

Overall, stakeholders were satisfied with AGN's Draft Plan including:

- the proposed price cut;
- opex proposals;
- capex proposals;
- proposed investment in renewable gas; and
- the customer and stakeholder engagement process.

Key areas of feedback and how we have responded in this Final Plan are shown in Table 5.9

At our meeting in May 2020 we shared how we are responding to feedback, and in June 2020 all members supported our approach for this Final Plan.

Public submissions on our Draft Plan

We received public submissions on our Draft Plan from the South Australian Federation of Residents and Ratepayers Associations Inc., the South Australian Council of Social Service, the Energy and Water Ombudsman SA and AGL.

All submissions are included in Attachment 5.5. A summary of submission feedback and how we are responding in this Final Plan is shown in Table 5.10.

Table 5.9: SARG/ RRG Workshop Feedback (Draft Plan)

SARG/ RRG Workshop Feedback (Key Themes)	Our Response in this Final Plan
What are AGN's longer-term plans for responding to COVID-19, including considering the broader economic impacts?	• Our Final Plan considers, where possible, the impacts of COVID-19 as introduced in Chapters 3 and 4, and considered in more detail in Chapter 12 on Demand. • We have adjusted our plans within the framework of the NGR – forecasts must be reasonable and use the best available information. • Our demand and growth capex forecasts have been updated reflecting HIA dwelling start forecasts; and • We will continue to monitor the impacts of COVID-19 on the South Australian economy and adjust our forecast if required in our response to the AER's Draft Decision.
Could customer preferences be impacted due to social and economic impacts of COVID-19?	• Our final round of customer engagement workshops were prior to COVID-19 restrictions. As such, consumer preferences were conducted in a 'stable environment' and as such reflect the longer term views of customers. • Our Final Plan considers, where possible, the impacts of COVID-19 as introduced in Chapters 3 and 4. • We also note this Final Plan price cut is marginally higher than the Draft Plan.
Price cuts and price path need to be clearly explained (real vs nominal) to customers	• We have included more information in this Final Plan regarding price cuts and the price paths for residential, business and commercial customers in real terms.
Some stakeholders would like AGN to consider a smoothed price path	• We are proposing a price cut of 7% (real) in this Final Plan and proposing a larger price cut in year 1 (over a smoothed path), as this was the preferred model by most customers and stakeholders recognising also the impact on the financeability of the business. This is discussed in Chapter 13.
Stakeholders would like to see more information included in the Final Plan in relation to the future of gas in this and the next regulatory period, the transition for customers and potential bill impact	• The future of gas and the pathway to decarbonisation are considered in this Final Plan including: • an overview in the Future of Gas section which considers options for renewable gases in the South Australian distribution network, actions already underway and included as part of our Final Plan. • Our proposed approach to depreciation of our assets is discussed in Chapter 9 of this Final Plan.

Table 5.10: Public Submissions on our Draft Plan

Organisation	Feedback	Our Response in this Final Plan
South Australian Federation of Residents and Ratepayers	• Support for the 8% before inflation (or 6% after inflation) price cut, seeking clarity in communication and a smooth line price path • Strong support for Hydrogen Park SA and other gas blending projects • Support for AGNs Capital Base Standard Asset Lives and the proposed mains and inlet replacement program • Support for standardising terms and conditions across network	• We have included an initial price cut of 7% (after inflation) in this Final Plan followed by smooth pathway from year 2. This was the preferred model for most customers and stakeholders, and aligns with forecast growth in the RAB over the period. This is discussed in Chapter 13.

South Australian Council of Social Service	• Broad support for the Draft Plan and engagement program with interest in:
	  ◦ modelling and transparent analysis of potential long term price impacts of COVID-19 on financeability;
	  ◦ if necessary, where potential trade-offs could be made to ensure that the plan still delivers an overall price cut, with a sustainable price path;
	  ◦ any required adjustments to the Draft Plan components such as demand forecasting and Unaccounted for Gas forecasts; and
	  ◦ Whether consumer preferences may have shifted as a result of COVID.
		• How we have responded to the potential impacts of COVID-19 in refining this Final Plan is discussed in Chapters 3, 4, and 12. Our demand forecasts have been adjusted to account for new dwellings growth forecast by HIA, and therefore lower connections growth as a result of the COVID-19 pandemic. However, we have maintained a price cut of 7% (after inflation), which is slightly above the price cut presented in the Draft Plan.

Energy and Water Ombudsman SA	• Support for AGNs proposal to develop a vulnerable customer assistance program	• We have included a vulnerable customer assistance program in Chapter 7 of this Final Plan.
AGL	• Preference for an even 'glide path' for network charges. • Very supportive of proposals such as the injection of hydrogen into the AGN SA network, noting the need to ensure that billing issues for customers are understood as a result of the different heating value • Keen to further explore residual cost of capex and opex proposals including how costs are determined including value and the business case relating to mains replacement • Additional modelling including consideration of forecasts in relation to COVID-19 impacts and the potential reduction in network asset life for the SA network (from 60 to 40 or 30 years)	• We have included an initial price cut in year 1, followed by smooth increases each year thereafter. This was the preferred model by most customers and stakeholders, and aligns with the forecast growth in the RAB over the period. This is therefore important to support the financeability of the business. This is discussed in chapter 13. • Information relating to our opex and capital expenditure proposals is provided in chapters 7 and 8 of this Final Plan. • How we have responded to the potential impacts of COVID-19 in refining this final plan are discussed in Chapters 3 and 13 of this Final Plan.

5.5.4Consumer Challenge Panel (CCP24)

We actively engaged and met regularly with the members of the AER's Consumer Challenge Panel (CCP24) throughout the development of this Final Plan.

In September 2019 we presented our proposed customer and stakeholder engagement program and discussed how we could best support CCP24 through the review.

In November 2019 we provided a business overview and discussed key focus areas and elements of our AA and our stakeholder engagement approach with CCP24. CCP24 also undertook a site tour to see first-hand the gas network operations and our mains replacement program.

Regular briefings and meetings on specific elements of our plans were held in in February, April and May 2020.

CCP24 members attended and observed numerous customer engagement activities including our Phase 2 (August - September 2019) and Phase 3 Customer Workshops (February - March 2020) held in metropolitan Adelaide (residential, business and CALD workshops) and across regional South Australia in Barossa, Mount Gambier, Port Pirie and Murray Bridge.

CCP24 members also attended our South Australian Reference Group meeting, co-design workshops; and all combined SARG and RRG workshops which focussed on our Draft Plan proposals. These workshops were held across March, April, May and June 2020.

CCP24 members also attended other ad-hoc engagement activities including our Information Session on the future of gas and hydrogen.

How we are responding to key areas of discussion with CCP24 is shown in Table 5.11.

CCP24 members (pictured left to right): Robyn Robinson, Mark Henley and Mark Grenning

Table 5.11: CCP24 Feedback on our Draft Plan

CCP Feedback (Key Themes)	Our Response in this Final Plan
Need for further information and narrative on the future of gas and the longer term vision to the network Need to consider potential changes to depreciation and capex related to new connections How is the stranded asset risk managed and the impact on consumers	• The future of gas and the pathway to decarbonisation are considered in this Final Plan including: • an overview in the Future of Gas section which considers options for renewable gases in the South Australian distribution network, actions already underway and included as part of our Final Plan. • Our proposed approach to depreciation of our assets is discussed in Chapter 9 of this Final Plan.
Consideration should be given around how price and the price path is explained (real vs nominal)	• We have included more information in this Final Plan regarding price cuts and the price paths for residential, business and commercial customers in nominal terms.
Consideration should be given to the potential impacts of COVID-19	• How we have responded to the potential impacts of COVID-19 in refining this final plan are introduced in Chapters 3 and 4, and considered in more detail in Chapter 12 on Demand.
Need for further information on mains replacement, meter replacement volumes and labour forecasts.	• Additional information relating to our opex and capital expenditure proposals is provided in chapters.
Consideration should be given to applying a productivity factor	• We are proposing to apply a productivity factor of 0.4% as explained in chapter 7 of this Final Plan.

5.6 Conclusion

We set out with the objective to develop a Final Plan which delivers for current and future customers, is underpinned by effective stakeholder engagement and is capable of being accepted by our customers and stakeholders.

We received positive feedback about our engagement program from customers and stakeholders. More than 90% of customers and stakeholders told us our program was inclusive, transparent, well run and of a high standard. 98% of customers felt they had an opportunity to have their say.

All stakeholders were satisfied that our engagement approach included the opportunity to ask questions, seek further information and that feedback has been responded to. 90% of stakeholders were satisfied that we delivered a no-surprises' engagement approach.

We have undertaken a wide range of engagement activities to support the development of our Final Plan, including direct customer and stakeholder engagement. This input has informed and shaped the development of our Final Plan over time. As noted in this chapter, 96% of customers support our plans.

As a result, our Final Plan has high levels of support from our customers and stakeholders.

We believe this plan delivers on our key objective to deliver a plan capable of acceptance. We are however keen to continue to engage closely with our customers and stakeholders through the AER review process and into the next AA period.

A complete set of customer and stakeholder feedback during engagement program, and how this has been incorporated in the Final Plan is provided in Attachment 5.2.


Australian
Gas Networks
operated by
apa

6 Services

IN THIS CHAPTER:

We propose to maintain the same reference and non-reference services in the next AA period.

Our proposed reference services include a range of haulage and complementary ancillary services.

Our proposed services for the next AA period are the same as those currently provided by the South Australian distribution network.

We offer a range of services to meet our customers' needs.

In the current AA period we have offered a number of different haulage and ancillary services.

The haulage services and most commonly used ancillary services have been classified as reference services – haulage reference services (HRS) and ancillary reference services (ARS). These services, which account for around 99% of the revenue earned in the current AA period, are the basis of the reference tariffs approved by the AER (in the current period).

A small number of less commonly used ancillary services have been classified as non-reference services, with the price reflecting the cost of providing the services by AGN.

Based on stakeholder feedback, our Reference Service Proposal (RSP) recommended a continuation of the current reference services into the next AA period. The RSP was submitted in June 2019 and was approved by the AER in November 2019.

The following sections provide further detail on the reference and non-reference services we propose to offer in the next AA period. Details of the price and other terms and conditions that will apply for the reference services are provided in subsequent chapters of this Final Plan.

6.1 Regulatory framework

Our Final Plan describes all of the pipeline services that we can reasonably provide.[1] It also specifies the reference services we intend to provide, which must be consistent with the AER's RSP decision.

On 27 June 2019 we provided our RSP to the AER for the next AA period.[2] This RSP was developed on the basis of feedback provided by our customers and stakeholders and the reference service factors set out in the NGR. The RSO proposed to maintain the same reference and non-reference services in the next AA period.

The AER consulted on the RSP with stakeholders and in November 2019 approved our proposal.[3]

Following the AER's decision our proposal for the next AA period must specify reference services consistent with the AER's decision unless there has been a material change in circumstances.[4]

6.2 Customer and stakeholder engagement

When developing our RSP, we met with our SARG and RRG (see Table 6.1). Through this

[1] NGR 48(1)(b)
[2] NGR 47A(1)
[3] See https://www.aer.gov.au/system/files/AER%20-%20Final%20Decision%20-%20AGN%20SA%202021-26%20Reference%20Service%20Proposal%20-%20November%202019.pdf
[4] NGR 48(1)(c)

engagement process, we asked whether:

- the services offered in the current AA period met our customers' needs;
- the current reference services are appropriate to continue in the next AA period; and
- any additional services should be reference services.

Our reference groups supported the retention of the existing reference and non-reference services for the next AA period.

Stakeholders considered the current services offered were appropriate for the next AA period.

Some members of the RRG suggested two additional services (Out of Hours Special Meter Reading and Same Day Service) should be reconsidered for future AA periods, but given low demand should remain ancillary non-reference services at this point.

No additional services were considered necessary by reference group members.

After submitting our RSP, the AER provided stakeholders an opportunity to comment before making its final decision. The AER received two submissions which were consistent with the feedback we had received in developing the RSP.

Table 6.1: Summary of customer and stakeholder engagement outcomes - Services

Services	
Customer and Stakeholder Feedback	**Our Response**
Stage 1 and 2 Engagement : Developing our Plans	
Stakeholders agreed that the current list of reference services is appropriate and noted that two non-reference services (Out of Hours Special Meter Reading and Same Day Service) could become reference services in future AA periods if demand increases for those services. SARG and RRG acknowledged that the services (reference and non-reference services) offered in the current AA period met customers' needs and the current reference services are appropriate to continue.	• Due to low demand, Out of Hours Special Meter Reading and Same Day Services will remain non-reference services. • Based on the stakeholder feedback received, we developed a proposal to maintain the same set of reference and non-reference services in the next AA period. • On 27 June 2019 we provided our Reference Service Proposal to the AER for the next AA period. The AER consulted on this proposal with stakeholders and in November 2019 approved our proposal.
Stage 3 Engagement: Draft Plan Consultation ⇨ Do you think the Reference Services we have proposed are appropriate?	
Stakeholders supported the proposed reference and non-reference services.	• We proposed to maintain the current reference and non-reference services in the next AA period, which is consistent with our Reference Service Proposal approved by the AER in November 2019.
Stage 4 Engagement : Refining our Plans	
No further feedback was received in relation to services.	• We made no further change to the Draft Plan.
Final Plan Outcome	
Stakeholders support our proposal to maintain the current set of reference and non-reference services in the next AA period, which is consistent with our Reference Service Proposal approved by the AER in November 2019.	

6.3 Services

Table 6.2 sets out the reference and non-reference services we propose to offer in the next AA period, consistent with the AER's RSP decision.

The classification of the services in this table as either reference or non-reference services is consistent with the classification that applies in the current AA period. It is also consistent with our June 2019 RSP, which the AER approved in November 2019.

As Figure 6.1 shows, the proposed reference services have accounted for around 99% of the revenue earned by the South Australian network in the current AA period. Non-reference services have accounted for just 0.5%.

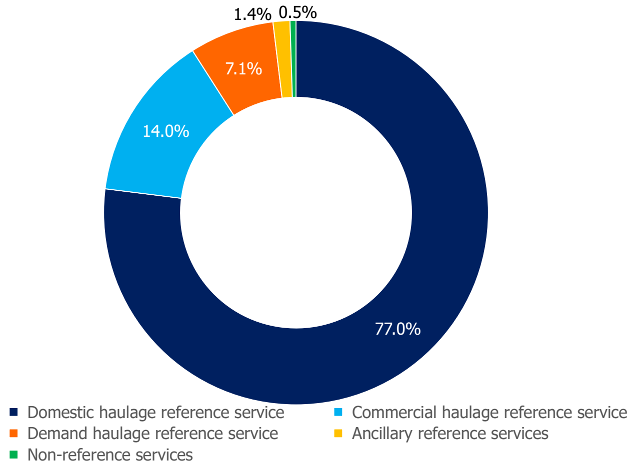
6.3.1 Reference services

In the next AA period, we propose to offer three haulage services and six ancillary services as reference services.

Consistent with the reference services factors, these services:

- are the most sought after services by our customers;
- are not generally substitutable with other pipeline services;
- have largely predictable costs that can either be attributed to individual users or reasonably allocated across users of a particular service;
- can aid prospective users in access negotiations and dispute resolution for other pipeline services; and
- will minimise the regulatory cost for all parties.

Figure 6.1: SA distribution network revenue share 1 July 2016 – 30 June 2019



6.3.2 Non-reference services

In the next AA period, we also propose to offer several non-reference services. These services have been classified as non-reference services because, in contrast to reference services:

- the demand for these services is relatively low and in most cases unpredictable; and/or
- the cost of providing most of these services varies markedly depending on the specific customer's requirements.[5]

Two of the proposed non-reference services (i.e. the out of hours special meter reading and same day service) are also substitutes for reference services.[6]

While we are not proposing to define these services as reference services in the next AA period, we understand customer preferences are changing. We will therefore re-evaluate the classification of services for the subsequent AA period and consult with our customer and stakeholders at that time.

6.4 Summary

We propose to maintain the current set of reference and non-reference services in the next AA period. Our customers support this approach, which is also consistent with our Reference Services Proposal approved by the AER in November 2019.

[5] For example, the cost of moving or removing a meter can range from $100 to $77,000, depending on the customer's site and needs

[6] This means that if customers are dissatisfied with the terms of access to these services, they can have recourse to the reference service.

Table 6.2: Summary of services for the South Australian distribution network 2021/22-2025/26

Services	General description
Haulage reference services	
Domestic haulage service	A haulage reference service that comprises the delivery of gas through an existing domestic Delivery Point (DP).
Demand haulage service	A haulage reference service that comprises the delivery of gas through an existing demand DP. A DP is a demand DP at a given time if: (a) that DP is not a domestic DP at that time; and (b) the quantity of gas delivered through that DP during the then most recent metering year was equal to or greater than 10TJ in total.
Commercial haulage service	A haulage reference service that comprises the delivery of gas through a commercial DP.
Ancillary reference services	
Special meter reading	A meter reading for a DP and provision of the associated meter reading data, that is in addition to the scheduled meter readings that form part of the haulage reference services (Special Meter Reads will be charged in accordance with location as either metropolitan or non-metropolitan).
Disconnection	The use of locks or plugs at the metering installation of a domestic or commercial DP in order to prevent the withdrawal of gas at the DP.
Reconnection	Action to restore the ability to withdraw gas at a DP, following an earlier disconnection (that is, the removal of any locks or plugs used to isolate supply, performance of a safety check and, where necessary, the lighting of appliances).
Meter and Gas Installation Test	On-site testing to check the measurement accuracy and soundness of a metering installation and the gas installation downstream of the metering installation.
Meter Removal	Removal of a meter in order to prevent the withdrawal of natural gas at the DP.
Meter Reinstallation	Reinstallation of a meter, performance of a safety check and lighting of appliances where necessary.
Ancillary non-reference services	
Meter Alter Position /Removal	When a customer is requesting the relocation of an existing gas meter to a new position, or the removal of a second meter on the premises.
Out of Hours Special Meter Reading	Request for an appointment to read a meter (Special Meter Reads are charged in accordance with location as either metropolitan or non-metropolitan).
Same Day Service	Request for a service on the same day as the request is made (the service is charged in addition to the charge for the requested service).
Relocate/Remove Service Pipe	Relocate the service or "Inlet" pipework.
Cut-off Service in Street for Debt	Requested by retailer, or by distributor as a matter of safety, when disconnection of supply is intended to be longer term due to non-payment of outstanding account by customer.
Reconnect Service in Street After Cut-Off	Reconnection of gas supply, previously disconnected in the street, following satisfactory payment by customer (or other agreed arrangement).
Upgrade Service Request	Increased gas load requires a larger capacity of service line to be installed.
Other Negotiated Service	A network service that is different from the Reference Services, on terms and conditions that differ in from the general terms and conditions.

1. The haulage reference services include the provision of unaccounted for gas and all services that are necessary in order for AGN to comply with its obligations.

7 Operating expenditure

IN THIS CHAPTER:

Our opex forecasts have been developed using the base-step-trend methodology approved by the AER.

Our opex includes initiatives to start blending renewable gas into our network, to better support vulnerable customers and to provide digital services more in line with other businesses.

Our opex forecast will ensure we continue to provide the safe, efficient, reliable and high-quality service our customers value.

Our operating expenditure forecast is below levels that were set for the current period, the benefits of which are now being passed on to our customers.

The operating expenditure (opex) we incur supports the safe, efficient and reliable delivery of gas to homes and businesses every day. It ensures we can meet the service expectations of our customers and the day-to-day needs of our workforce.

We have applied the AER's base-step-trend methodology to forecast efficient opex for the next AA period. This means for most opex items we look at the total costs we are incurring now and project those costs forward. However, for some items we develop specific forecasts which consider the individual factors that drive those costs.

On an aggregate basis, our opex is forecast to be $357 million over the next AA period (see Table 7.1). This is $3 million higher than in our Draft Plan, and around 8% ($27 million) higher than what we expect to incur in the current AA period (forecast to 30 June 2021).

We achieved savings in the current period largely due to one-off integration benefits after establishing AGIG in 2017, the benefits of which are now being passed on to our customers.

Table 7.1 Total forecast opex ($million, 2020/21)

	Current AA period	Next AA period	Drivers for change	
Opex (ex UAFG)	290.3	310.2	✓	Embedded efficiencies made in the current period, customer driven and other step changes and the 'trend' component of our opex forecast (real cost escalation, customer growth and productivity)
Proposed change in capitalisation	-	-	✓	We have decided not to reduce the level of overheads that are capitalised into our asset base
UAFG	40.3	47.2	✓	Reflects the current market cost of gas, including the purchase of up to 20% green or renewable gas
Total opex	**330.5**	**357.4**		

Note: Totals may not add due to rounding

Forecast opex is below our allowance for the current period, reflecting merger savings from 2017. The increase in forecast opex for the next AA period compared to the current period is attributed to:

- a positive trend (incorporating input cost escalation, output growth and productivity)
- in July 2021 we will have 464,000 customers compared to 436,000 in July 2016;
- $8 million in step changes for our vulnerable customer assistance program, digital customer experience and insurance costs; and
- the increased costs of unaccounted for gas (UAFG), reflecting the higher gas prices that we expect to pay.

Across all other categories we have been able to keep costs for the next AA period at similar levels as in the current AA period.

Although a modest increase in opex is expected in the next AA period (as shown in Figure 7.1 and Figure 7.2), the incentives provided by the operation of the Efficiency Benefit Sharing Scheme (EBSS), coupled with our internal and external controls, will continue to ensure that the opex we incur is both prudent and efficient. These incentives will also ensure that any cost savings are passed through to customers, in the same manner as the efficiencies achieved in the current AA period will be passed through.

The following sections provide further detail on the standard our forecasts must meet under the regulatory framework, the forecasting method we have used and our forecasts for the next AA period. Further detail is also provided on how we have performed in the current AA

Figure 7.1: Opex excluding UAFG

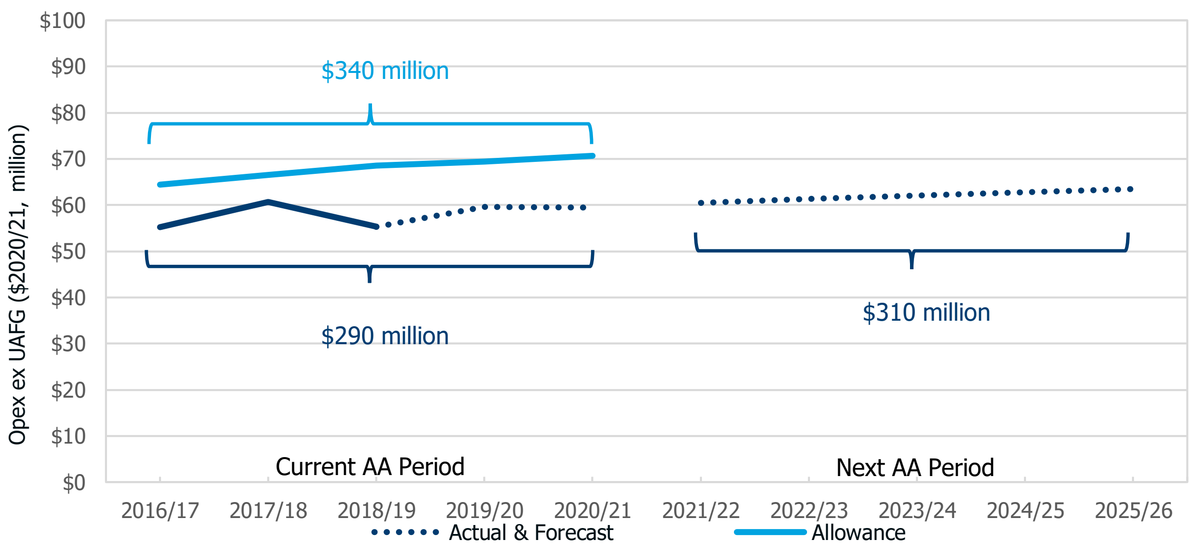
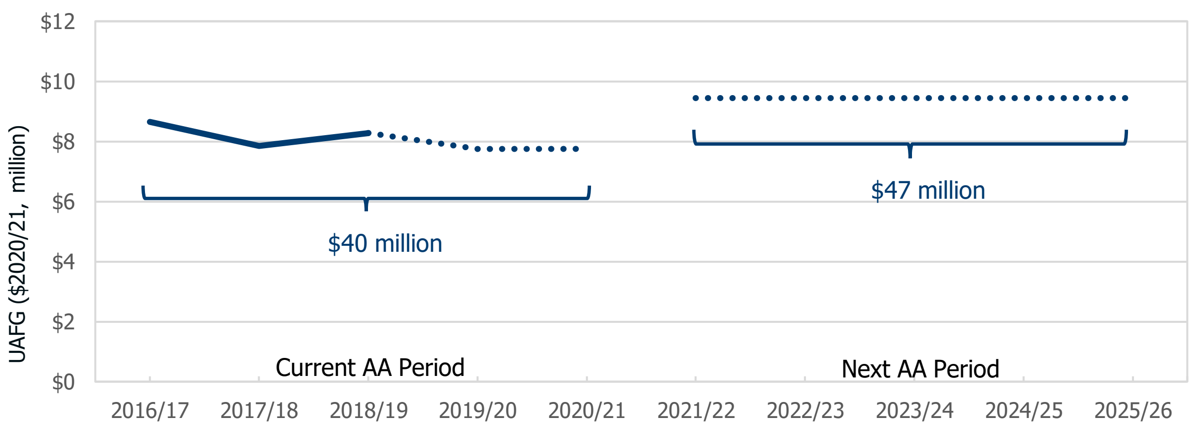


Figure 7.2: Actual and forecast UAFG



period. Further information on how we ensure the expenditure we incur (capex and opex) is both prudent and efficient is available in the *Governance* section.

All numbers quoted in this section are expressed in 2020/21 dollars, unless otherwise stated.

7.1 Regulatory framework

Our AA proposal must include the forecast opex for the next AA period.[1]

In keeping with the NGR, our forecast must reflect the expenditure that would be incurred by a prudent gas distribution business, acting efficiently, in accordance with good industry practice, to achieve the lowest sustainable cost of providing services to our customers.[2]

Our forecasts must also be arrived at on a reasonable basis and represent the best forecast or estimate possible in the circumstances.[3]

Our AA proposal must also include operating expenditure incurred during the current AA period.[4]

7.2 Customer and stakeholder engagement

Customers told us their top priorities are price and affordability, reliability of supply, and maintaining public safety.

Customers highly value an uninterrupted supply of gas in their homes and business and are satisfied with current service levels.

Customers expect AGN to deliver a high level of public safety and feel that safety is well managed.

With this in mind, our opex proposal is based on maintaining the current levels of reliability and safety our customers expect (see Table 7.2).

Customers expect timely customer service by knowledgeable staff who demonstrate empathy and understanding in responding to queries or resolving issues. Customers and stakeholders are satisfied with our current customer service levels, however they would like to see more digital services be introduced over time. Our opex proposal supports maintaining our strong track record of customer service.

We have developed our opex proposal in consultation with stakeholders. We shared our draft opex proposal as it was developed with our reference groups to seek feedback on our investment priorities and levels of expenditure.

We presented our draft proposal to our reference groups in October 2019, February 2020 and as part of our deep dive workshops during draft plan consultation in March 2020.

Stakeholders were supportive of how we have developed our proposal. They were also keen to understand that our costs are efficient, which is shown in section 7.3 of this Chapter.

We worked with customers to develop a number of proposals, which will improve service quality and accessibility and create future options for the network as we transition to zero emissions.

Customers told us finding ways to lower emissions was very or extremely important to them, which is consistent with our own views. Through the customer workshops we have developed an initiative to offset a portion of our UAFG with renewable gases (see Table 7.4).

We also engaged with the experts from the social service sector via co-design workshops to develop a Vulnerable Customer Assistance Program (VCAP) (see Table 7.3).

[1] NGR 72(1)(e)
[2] NGR 91
[3] NGR 74
[4] NGR 72(1)(a)(iii)

Table 7.2: Summary of customer and stakeholder engagement outcomes – Operating expenditure

Operating Expenditure

Customer and Stakeholder Feedback	Our Response
Stage 1 and 2 Engagement : Developing our Plans	
Customers' top priorities are price / affordability, reliability of supply and maintaining public safety. Customers expect AGN to deliver high levels of public safety and feel that safety is currently well managed. 92% customer support to maintain current levels of public safety and 96% customer support to maintain current levels of reliability. Customers and stakeholders support continued customer service levels, with support for additional digital service channels to be made available. Stakeholders are keen to ensure that our costs are efficient, and that we can demonstrated this. Stakeholders were comfortable with the preliminary proposals presented to SARG and RRG in February 2020.	• Our opex proposal supports maintaining current levels of reliability, public safety and customer service. • Our totex forecast (combined opex and capex) for the next AA period is consistent with the levels we expect to incur in the current AA period. • Our opex forecast has been developed using previously approved regulatory methodologies.
Stage 3 Engagement : Draft Plan Consultation ⇨ Do you support our approach to forecasting operating expenditure? Is there sufficient information to understand our proposals and the basis of the costs included in our forecast?	
96% customer support for our investment proposals in our Draft Plan, noting support for the inclusion of new digital customer service channels. SARG and RRG indicated broad support for our proposed opex. CCP24 queried our approach to productivity and suggested consideration be given to applying a productivity factor. Stakeholders noted that vulnerable customers are experiencing financial stress with recent stagnation in wage growth, and queried the assumption that input costs escalate at 0.5%.	• We agreed to continue to refine our opex proposal which supports maintaining current levels of reliability, public safety and customer service. • We agreed to undertake further analysis to determine a productivity adjustment. • We noted that input cost escalation would be determined by the AER as part of other network business' reviews that were occurring at the time. We advised we will apply the AER's approach, consistent with a plan capable of acceptance.
Stage 4 Engagement : Refining our Plans	
SARG and RRG broadly support our opex proposal to maintain current levels of reliability, safety and customer service (with new digital service channels). SARG and RRG support our proposal to include a productivity adjustment.	• In response to stakeholder feedback we have proposed a productivity adjustment. • Our operating expenditure proposals are provided in Chapter 7 of this Final Plan. • We have also applied the same approach to output growth as that used by the AER in its most recent decision for Jemena Gas Networks.
Final Plan Outcome	
Our opex proposal delivers against customer expectations that current levels of reliability and safety are maintained. It also delivers against customer expectations that current levels of customer service be maintained, with the inclusion of improved digital service channels. We have applied a productivity factor of 0.4% to our opex forecast in response to CCP24 feedback. Customers and stakeholders support our approach and levels of operating expenditure included in this Final Plan.	

Table 7.3: Summary of customer and stakeholder engagement outcomes – VCAP

Operating Expenditure – Vulnerable Customer Assistance Program (VCAP)	
Customer and Stakeholder Feedback	**Our Response**
Stage 1 and 2 Engagement : Developing our Plans	
• Customers' top priority is price / affordability. • Supporting vulnerable customers in the community was identified as a focus area by customers and stakeholders, believing that AGN has a role to play. • Customers told us that AGN has a social responsibility to support people in the community who are experiencing vulnerability including pensioners, low income earners and health issues.	• Assisting vulnerable customers was identified as a key issue for consideration in developing our proposals. • SARG and RRG endorsed engagement with experts the social service sector via co-design workshops.
Stage 3 Engagement : Draft Plan Consultation ⇨ Do you support investment in a vulnerable customer assistance program? Do you have any feedback on the activities we have proposed?	
• From the co-design workshops, stakeholders told us key focus areas for AGN should be: understanding customers better; doing more in the community through public engagement and education; being proactive in situations where customers are vulnerable; and being present in the affordability debate. • 76% customer support for the Draft Plan proposal for a Vulnerable Customer Assistance Program (VCAP). • Customers and stakeholders noted that AGN could work in partnership with social service and not-for-profit organisations to deliver the VCAP over the next AA period. • Experts from the social service sector supported the Draft Plan proposal for a VCAP. We also received supportive submissions from EWOSA and SAFRRA. • Stakeholders expressed a desire to understand AGN's plans in more detail once determined. • Given the potential social and economic impacts of COVID-19 stakeholders highlighted assisting vulnerable customers as even more important.	• AGIG is an Energy Charter signatory and is developing a Vulnerable Customer Strategy which will incorporate feedback from the co-design process. • We proposed to further develop the VCAP for inclusion in our Final Plan, noting ongoing engagement will be a critical part of developing the program over the next AA period.
Stage 4 Engagement : Refining our Plans	
• Stakeholders supported the proposal to include the VCAP recognising that AGN will continue to work with customers and stakeholders in developing the model for implementation.	• The VCAP is included as part of our operating expenditure proposal in Chapter 7.
Final Plan Outcome	
✔ Customers and stakeholders support our proposal to invest in a Vulnerable Customer Assistance Program which is included in this Final Plan (Chapter 7). Customers and stakeholders are keen to continue engaging with us to further develop, refine and implement our VCAP over the next AA period (recognising the need to continually innovate and respond to changing circumstances).	

Table 7.4: Summary of customer and stakeholder engagement outcomes – Replacing UAFG with Renewable Gas

Operating Expenditure – Replacing UAFG with Renewable Gas	
Customer and Stakeholder Feedback	**Our Response**
Stage 1 and 2 Engagement: Developing our Plans	
• The future of gas and renewables is a key area of interest for stakeholders. • Almost 9 in 10 customers (87%) told us that finding ways to lower carbon emissions is very or extremely important to them, and most expect AGN to proactively reduce its environmental footprint. • Customers told us they are very interested in our actions to reduce emissions and contribute to environmental sustainability, in particular the role of hydrogen as a renewable gas.	• In addition to existing plans, we developed a further proposal to reduce carbon emissions by replacing unaccounted for gas (UAFG) with renewable gas to be tested with customers including by showing costs and bill impacts. • We noted the high level of interest by customers and stakeholders in renewable gas.
Stage 3 Engagement: Draft Plan Consultation ⇨ Do you support investment in replacing lost gas with renewable gas to reduce carbon emissions?	
• Customers support AGN's proposal to reduce carbon emissions by replacing UAFG with renewable gas, with 84% support at an additional cost \$1.50 to \$5.50 on the average residential bill. • Customers told us that the proposal is good value for money given the minimal price impact for potentially significant environmental benefits and the benefit for future consumers. • Stakeholders broadly supported our proposal, but were keen to understand volumes and pricing.	• At our 28 May SARG/ RRG meeting we shared further information on our proposal to replace UAFG with renewable gas. • We advised that we are proposing to replace 20% of UAFG with renewable gas. • We proposed to further develop and refine our proposal to offset UAFG with renewable gas for consultation with SARG and RRG members.
Stage 4 Engagement : Refining our Plans	
• Stakeholders supported the proposal to replace up to 20% of UAFG with renewable gas.	• The proposal to replace up to 20% of UAFG with renewable gas is included as part of our operating expenditure proposal in Chapter 7.
Final Plan Outcome	
✔ Customers and stakeholders support our proposal to replace up to 20% of UAFG with renewable gas as part of our operating expenditure proposal in this Final Plan.	

7.3 How we develop our opex forecast

Our opex forecast for the next AA period has been developed using the base-step-trend approach for all costs aside from UAFG and debt raising costs. A bottom-up approach has been used to develop category specific forecasts for opex categories that cannot reasonably be estimated using the base-step-trend approach (i.e. debt raising and UAFG costs).

The use of category specific forecasts is consistent with the AER's preferred approach and the approach we have used in prior AA periods.

Figure 7.3 illustrates the key elements of this approach.

7.4 Our opex forecast for the next AA period

The following sections set out how each element of our opex forecast has been developed.

7.4.1 Base year opex

Under the base-step-trend approach the actual costs incurred in the penultimate year of the current AA period can be used, provided they are efficient, as the base for forecasting costs in the next AA period.[5]

At the beginning of the 2016-21 Access Arrangement period, the AER found that our proposed opex was efficient. Attachments 7.4 and 7.5, prepared by Economic Insights show that, since that time, AGN SA has seen the fastest total factor productivity growth and opex partial factor productivity growth in the country.

Figure 7.3: Forecasting method used for opex

Step 1 Base

Determine the base year opex that will be used to forecast opex in the next AA period by:

(a) taking the opex from the penultimate year of the current AA (by virtue of the operation of the Efficiency Benefit Sharing Scheme, expenditure in this year represents a prudent and efficient base for forecasting opex);

(b) adjusting the base year opex determined in (a) to remove:

- (i) the effect of one-off (or non-recurring) costs;
- (ii) those opex categories where the base-step-trend method does not produce the best forecast (e.g. unaccounted for gas and debt raising costs); and
- (iii) account for the effect of any reclassification of capex to opex and vice versa.

Step 2 Step

Account for any step changes in opex that are expected to occur over the next AA period (e.g. as a result of changes in legislative or regulatory obligations) that are not adequately compensated for in the base year or rate of change.

Step 3 Trend

Account for **changes in** input costs, output growth and productivity growth that is expected to occur in the next AA period through the application of a 'rate of change' to the base year opex and, where relevant, step change opex, where:

rate of change = input cost escalation + output growth – productivity growth

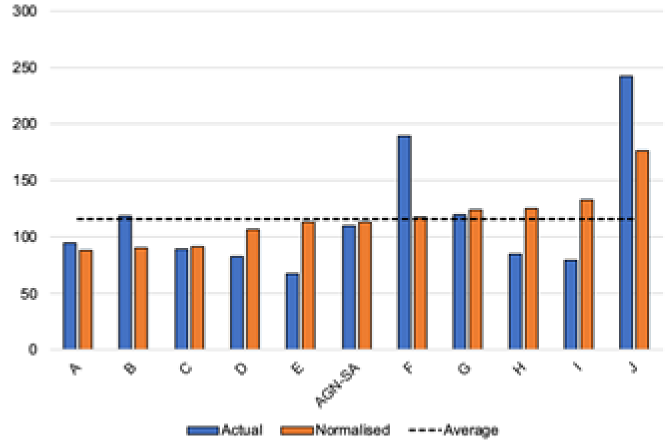
Step 4
Category specific forecasts for other opex categories

Add the expenditure that is expected to be incurred for other opex categories that can't be forecast using the base-step-trend approach (e.g. unaccounted for gas and debt raising costs)

5 See AER, 2019, Forecasting productivity growth for electricity distributors: Final decision paper, March 2019, p7

Other evidence provided by Economic Insights in the same attachments draw similar conclusions, particularly when the raw productivity data are normalised to account for outside factors beyond the control of the networks. This evidence supports 2019/20 being efficient, and therefore suitable for use as the base year to forecast opex for the next AA period.

Figure 7.4: Economic Insights Normalised relative efficiency scores



Economic Insights has compared multilateral total factor productivity scores across network businesses and normalised the scores to allow for the scale and customer density of networks, i.e. to address the problem highlighted by the AER. The results of this show that our South Australian network efficiency score is consistent with the industry average (see Figure 7.4). We therefore have confidence our base year opex is efficient.

Other factors providing evidence that our costs are prudent and efficient include the operation of both:

- the EBSS (see Chapter 11), the objective of which is to provide a continuous incentive to pursue efficiencies and achieve the lowest sustainable cost of providing services in every year; and
- our internal and external controls on asset management, procurement and financial governance (see *Governance*), the objectives of which are to ensure we undertake opex in a prudent and efficient manner, in accordance with good industry practice.

To this end, the AER noted in its decision for the current period that:

"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."[6]

The costs we incur in the base year will therefore provide a prudent and efficient basis for forecasting opex in the next AA period.

At this point in time we do not have finalised actual costs for this year. We have therefore developed an estimate of these costs based on the actual opex incurred to March 2020 and a forecast for the remaining three months of the 2019/20 financial year.

These costs will be finalised after the submission of this Final Plan and will be available to the AER when it makes its Draft Decision.

Removal of non-recurrent opex

As noted in Figure 7.3, once the base year costs are determined, they must be adjusted to remove any non-recurrent costs.

The opex we estimate for 2019/20 reflects our expenditure on recurrent activities. We note we are not seeking any change (positive or negative) for the cost of providing reference services in regards to managing COVID-19.

Accounting for changes to capitalisation of overheads

The base year costs must also be adjusted to account for any changes in the accounting treatment of costs.

In this Final Plan we have decided not to move any of our capitalised overheads to opex in the next AA period. This is a change from the position in our Draft Plan where we proposed to include some of the capitalised overheads for 2019/20 in the base year opex.

While we consider the proposal to shift some of the overheads from

[6] AER 2015, "Attachment 7: Operating Expenditure | Draft Decision Australian Gas Networks 2016 to 2021", November 2015, pg. 7-14.

capex to opex better aligns with accounting rules, other updates to inputs since publication of the Draft Plan resulted in upward pressure on price. To mitigate this impact, and to deliver a price outcome in line with our Draft Plan, we have elected not to pursue this initiative. This reflects the already noted finding that price is an important priority for our customers, particularly in the current circumstances surrounding the COVID-19 pandemic.

Therefore, there are no adjustments to our base year opex to account for changes to capitalisation of overheads in this Final Plan.

Removal of opex categories to be forecast separately

The final adjustment that must be made to the base year costs is to remove those opex categories for which category specific forecasts provide a better estimate of efficient costs.

As noted above, we have developed separate forecasts for the costs associated with UAFG and debt raising costs. We have therefore excluded $8 million from the 2019/20 forecast expenditure to remove the costs associated with UAFG, and $1 million for debt raising costs.

Base year opex used for forecasting

The base year opex that we have used for the purposes of the Final Plan is $58 million. This is $1 million higher than the $57 million in our Draft Plan. The movement from the Draft Plan to Final Plan in the base year is driven by:

- our decision not to move any of our capitalised overheads into opex as we had proposed in our Draft Plan; and
- updating for an additional three months of actual opex costs.

As noted above, this base year value will be updated after submission of this Final Plan to reflect the actual costs incurred in 2019/20.

Table 7.5: Establishing the base year for forecasting opex in the next AA period ($million, 2020/21)

Category	2019/20 forecast
Total opex	68.7
Minus UAFG	9.7
Minus Debt raising costs	1.0
Base year for forecasting	**58.0**

7.4.2Step changes

The next element of the base-step-trend approach requires any 'step changes' in costs in the next AA period to be identified. Step changes may arise as a result of changes to legislation, regulatory obligations or new activities.

We are proposing three step changes to opex in the next AA period, which are:

- a vulnerable customer assistance program;
- a digital customer experience project; and
- an incremental increase on our insurance premium.

The first two of these step changes represent new activities developed in response to feedback through our customer and stakeholder engagement program.

Our vulnerable customer assistance program (VCAP) will fund new activities to better support vulnerable customers. The step change of $780,000 per year (or approximately $1.50 per customer per year) over the next AA period will provide:

- A dedicated resource to run the program;
- Assistance for appliance rebates and audits for vulnerable customers;
- Rebates for new connections;
- Rebates for switching to more efficient gas appliances;
- Gas efficiency audits; and
- CRM enhancements for improved/ targeted services.

This proposal follows engagement with our customers and stakeholders on the potential vulnerable customer initiative as was highlighted in our Draft Plan. Specifically the new activities we are proposing reflect that:

- 76% of customers support or strongly support investment in a vulnerable customer assistance program at a cost of between $1 –$2 per annum on their bill;
- we received supportive submissions from key community sector stakeholders, EWOSA and SAFRRA; and
- the SARG and RRG were supportive, but requested more detail be provided in our Final Plan.

In developing this proposal, we have also used insights gained through our series of co-design workshops, which considered the topic of *How might AGN better support vulnerable customers now and in the future?*

More detail on the proposed activities and forecast costs can be found in Attachment 7.2.

Our digital customer experience project involves a step change, averaging around $280,000 per year (or approximately $0.50 per customer per year over the next AA period). The proposal follows insights gained during engagement with our customers and stakeholders. Specifically, we found customers expect our communication channels and service options to reflect broader market trends, which increasingly means offering a variety of digital communication channels.

More detail on the proposed digital customer experience activities and forecast costs can be found in Chapter 8 and Attachment 8.8 (Business Case SA137).

In this Final Plan we are not proposing funding for a Community Education Centre, which was outlined in our Draft Plan. While the centre is important and would deliver benefits to customers, we have decided not to fund this in the next AA period.

58% of customers at our customer workshops were supportive of this initiative, however in light of CCP and other stakeholder feedback regarding the current economic climate we will consider seeking funding for this project from alternative sources, such as state and federal government grants. We will continue to engage with the community and stakeholders as we do this (see Attachment 5.2).

We are also seeking a step change on account of increases to insurance premiums over and above the trend expected over the next AA period. We commissioned Marsh to assess the global insurance market and provide advice on the expected movement of insurance premiums. The Marsh report (Attachment 7.7) identified that, due to movements in the global insurance market, premiums are expected to be nearly $3 million higher over the next AA period. We have reflected this in our opex forecast.

7.4.3Trend

The final element of the base-step-trend approach requires consideration be given to the extent to which our costs are expected to change over the next AA period. Such change could be as a result of:

- input cost escalation;
- output growth; and
- productivity growth.

These three factors are accounted for by applying the trend rate of change to the base year opex and, where relevant, any step changes.

Since our Draft Plan we have concluded work with a range of independent experts engaged to advise us on these factors. This results in an average trend rate of change of 1.0% per year, which is 0.4% lower than the rate we assumed in our Draft Plan.

The movement in the rate of change since the Draft Plan is driven by updated labour cost escalation forecasts, updated demand forecasts which drive growth in customer numbers and, as well as the application of a productivity growth factor. Further detail on the key determinants of this rate of change is provided below.

The expert advice we considered to determine these factors is provided in Attachments 7.3, 7.4, and 7.5.

Input cost escalation

The input cost escalator accounts for costs that are expected to increase at a different rate than inflation (real cost escalation).

To calculate the input cost escalation rate we have applied the AER benchmark weights as follows: [7]

- labour costs are assumed to account for 59.7% of our opex and are forecast to grow in real terms by an average annual rate of 0.8% per year over the next AA period (no change from our Draft Plan); and
- materials costs are assumed to account for 40.3% of our opex and are assumed to grow in real terms by 0% per year over the next AA period.

The growth rate assumed for labour costs is based on the average of two independent Wage Price Index forecasts for Electricity, Gas, Water and Wastewater Services developed by Deloitte Access Economics and BIS Oxford (as shown in Table 7.6). This is consistent with the approach taken in the current AA period, and also reflects the approach the AER has applied in its most recent decisions for other energy businesses.

The materials cost growth rate of zero is the same assumed by the AER in its recent regulatory decisions for ourselves and other energy businesses.

The application of these assumptions results in a real (i.e. before inflation) average annual input cost escalator of 0.5% per year over the next AA period (see

[7] These weights are based on the AER's benchmark weights.

Table 7.7).

This is consistent with what we had proposed in our Draft Plan and reflects the latest forecasts from Deloitte Access Economics and BIS Oxford (See Attachment 7.8 and 7.8.1).

Our application of this approach reflects our commitment to developing a plan capable of acceptance.

Output growth

The output growth factor accounts for the additional opex we will incur as a result of the forecast growth in output.

Our proposed output growth factor is based on the most recent approach approved by the AER and applied by Jemena for its New South Wales gas distribution network. It has therefore been calculated having regard to the forecast growth in:

- kilometres of network over the next AA period; and
- customer numbers over the next AA period.

These forecasts, which are set out in Chapters 8 and 13, have been weighted with customer numbers given a 51% weighting and kilometres a 49% weighting consistent with the most recent AER decision.

The application of these assumptions results in an average annual output growth rate of 0.9% per year over the next AA period (see Table 7.8).

Productivity growth

In applying the base-step-trend approach, the AER considers whether there should be an adjustment to capture expected changes in the productivity of the business (which could be positive or negative).

We proposed a productivity factor of 0% per year for the next AA period in our Draft Plan. This was consistent with the productivity growth estimate of 0% applied by the AER in the most recent decision for our Victorian and Albury businesses (based on evidence that productivity growth was actually negative), and for South Australia prior to this for the current AA period.

We received stakeholder feedback on our Draft Plan to obtain further expert evidence on an appropriate productivity adjustment to apply over the next AA period. We therefore engaged ACIL Allen to further analyse productivity trends, and the most appropriate productivity growth to apply to our South Australian network (Attachment 7.3).

ACIL Allen developed models that seek to explain key drivers of changes in the opex incurred by gas distribution businesses in the past, including due to technical change (referred to as opex cost function econometric analysis). ACIL Allen undertook this analysis using data from 2004/05, noting the following caution from the Productivity Commission on using information prior to this time:

"Similarly, the electricity, gas, water and waste services industry [EGWWS], which was a target of microeconomic reforms through the 1980s and 1990s and made a strong contribution to labour productivity at that time, has since given up those gains and overall detracted from productivity growth during the period after 2005."

We also note evidence from the ABS, which shows productivity growth in the EGWWS sector has slowed considerably from the last full business cycle and is currently negative. Whilst the levels of productivity in the wider sector may differ from gas, the patterns of growth movement have been the same in the past and we consider this is likely to still be the case.

ACIL Allen, estimated the impact of technical change (used to proxy productivity growth) across four different models, which provided a range for productivity growth from 0.1% to 0.4%. ACIL Allen considered that 0.17% was the best estimate of productivity growth, reflecting an average of the four estimates from its analysis. Using analysis that takes into account customer numbers and network length, consistent with the approach taken to estimate output growth in this Final Plan, would increase the estimate of productivity growth to 0.25% per year.

In considering this advice, alongside feedback received from our customers and stakeholders (including on the importance of price), we have decided to apply a productivity factor at the upper end of the range provided by ACIL Allen to be conservative. We are proposing in our Final Plan to apply a productivity growth factor of 0.4% per year over the next AA period, which results in a $3 million reduction in total opex when compared with a factor of 0% used in our Draft Plan and in previous regulatory decisions.

By way of a check, we note that if an average of the productivity growth used by the AER for electricity businesses (of 0.5%) and the above-mentioned ACIL Allen productivity growth of 0.25%, would support a productivity growth of slightly less than 0.4% per year.

Table 7.6: Calculation of annual real labour cost escalation

Labour cost estimates	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
BIS Oxford	1.09%	1.09%	1.26%	1.51%	1.38%	1.18%
Deloitte Access Economics	0.37%	0.37%	0.34%	0.45%	0.44%	0.44%
Average	**0.73%**	**0.73%**	**0.80%**	**0.98%**	**0.91%**	**0.81%**

Table 7.7: Calculation of annual input cost escalation (weighted average of real cost escalation for labour and materials)

Category	Weight	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Labour	59.7%	0.73%	0.73%	0.80%	0.98%	0.91%	0.81%
Materials	40.3%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Annual input cost escalation		**0.43%**	**0.44%**	**0.48%**	**0.59%**	**0.54%**	**0.48%**

Table 7.8: Calculation of the output growth factor

Category	Weight	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Customer numbers	50.6%	0.90%	0.61%	1.09%	1.27%	1.36%	1.32%
Network length (km)	40.4%	1.00%	0.58%	0.63%	0.62%	0.57%	0.53%
Weighted output growth factor		**0.95%**	**0.59%**	**0.86%**	**0.94%**	**0.96%**	**0.92%**

Table 7.9: Productivity growth factor

Category	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Productivity	--	0.40%	0.40%	0.40%	0.40%	0.40%

7.4.4 Category specific forecasts

As noted above, separate forecasts have been developed for Unaccounted for Gas (UAFG) costs and debt-raising costs. The way in which these costs have been estimated is outlined below.

UAFG forecast

UAFG is the difference between the quantity of gas entering the network and the quantity of gas delivered to our customers. This difference may arise as a result of leaks, metering inaccuracies and/or gas theft. We are required to purchase gas to make up this difference.

We engaged an independent expert to estimate the volume of UAFG for the SA network over the next AA period (Attachment 7.6, confidential).

The volume forecast of UAFG utilises an average of actual UAFG settled by AEMO for 2015/16, 2016/17, and an estimate for 2017/18. This is consistent with the approach most recently used for our Victorian and Albury distribution network.

Our UAFG forecast has then been calculated by multiplying:

- the three-year average volume of UAFG; *by*
- the estimated average price of gas, which is based on current market conditions (Attachment 7.9). This estimated price will be replaced by the actual price we achieve with a third party gas supplier, which is expected to be finalised before the AER Draft Decision.

This method produces a forecast of $47 million for the next AA period. This is $2 million lower than the $49 million in our Draft Plan. The decrease is driven by new indications from the market as to of the price we are able to contract at for UAFG.

Due to the confidential nature of the price we pay for UAFG, we cannot publish our forecast volumes. This information is provided confidentially to the AER. The AER will assess the reasonableness of both our volume and price forecasts.

We are also proposing to incorporate renewable/carbon neutral gas from a bioenergy project to provide a portion of our UAFG in the next AA period (we estimate this could be up to 20% of our total UAFG requirements).

This initiative follows our customer and stakeholder engagement where:

- 87% of customers considered it very important or extremely important that we consider ways to lower carbon emissions; and
- 84% of customers supported or strongly supported investment in renewable gas for UAFG at a cost of $1.50 – $5.50 on the average annual bill.

When we explored potential future of gas initiatives with our customers at our customer workshops, this was the highest ranked option and we have now incorporated it in this Final Plan. There was also strong support for this option from our reference groups.

We also consider that this initiative is a very important step as we transition to a low carbon economy.

We are actively pursuing this opportunity with interested third parties, and will engage further with stakeholders and the AER as the matter progresses.

We consider the negotiated price will closely reflect the estimate we have used in our Final Plan, inclusive of the renewable gas price.

Debt-raising cost forecast

Debt-raising costs are the costs we (and other businesses) incur when raising or refinancing debt and the costs associated with maintaining a debt facility.

Our debt-raising cost forecast has been calculated using the AER's standard benchmark method.

The application of this method produces a debt-raising cost forecast of $4 million for the next AA period. This has not changed from our Draft Plan.

7.4.5Summary

Figure 7.5 and Table 7.10 set out our forecast opex for the next AA period. As explained in this chapter, our opex forecast has been developed by applying AER preferred methodologies.

We expect to incur $362 million in opex over the next AA period, inclusive of $4 million of debt raising costs. This is $4 million higher than the $358 million in our Draft Plan and 8% higher than what we expect to incur in the current AA period (forecast to 30 June 2021). The increase can largely be attributed to $8 million in opex step changes (non-base year opex) and $7 million increase in the cost of UAFG, offset by expected improvements in productivity.

As noted above, we will update our estimate of the 2019/20 base year costs with the actual costs incurred in that year, once the information is available.

Our opex in the next AA period aligns with our vision.

Delivering for customers

- We will continue to respond to leaks on our network quickly (one of the most important activities we undertake to ensure public safety).
- We will maintain our network assets as required by our asset management and asset specific plans.
- We will undertake other operational activities to maintain our strong safety, reliability and customer service performance.
- We will undertake new customer service activities to support vulnerable customers and more digital customer services.

Being a good employer

- We will undertake workplace health and safety programs, and employee and contractor training and development initiatives to maintain a healthy, safe, engaged and skilled workforce.

Sustainably cost efficient

- We will pass through opex savings made in the current period to our customers.
- We have only proposed step changes for new activities that we believe we should be delivering and have also been supported by our customers and stakeholders, along with forecast increases in insurance costs related to the upward movements forecast in the insurance market cycle.
- We will replace up to 20% of our UAFG with green or renewable gases and continue to incentivise new connections to our network where it is economically efficient to do so. We will ensure that the services we provide will deliver for all South Australians, including those in vulnerable circumstances. That is why we are pursuing opportunities to do more to provide further support to those in need, on top of the measures we already have in place.

Figure 7.5: Opex in the next AA period by category ($million, $2020/21)

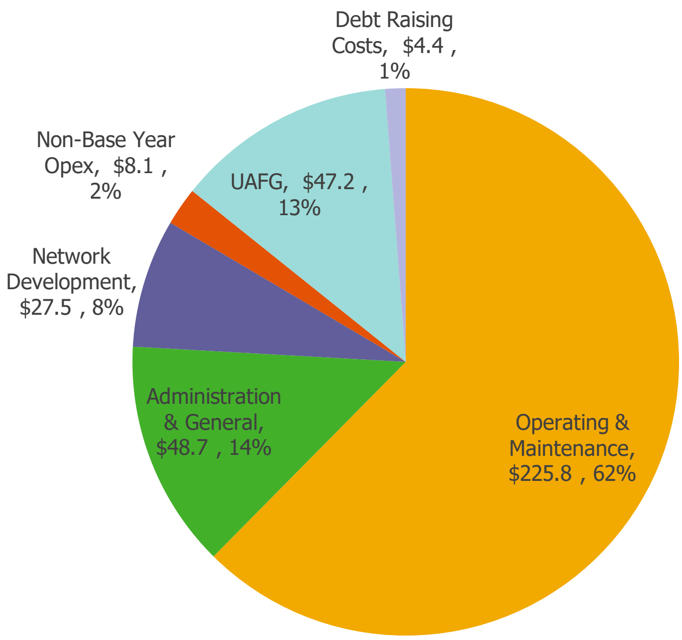


Table 7.10: Opex forecast summary ($ million, 2020/21)

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Base year opex forecast	58.0	58.0	58.0	58.0	58.0	290.0
Step changes	1.3	1.6	1.7	1.8	1.8	8.1
Change in capitalisation	-	-	-	-	-	-
Trend	1.2	1.7	2.4	3.1	3.7	12.0
UAFG	9.4	9.4	9.4	9.4	9.4	47.2
Total opex forecast (ex debt raising costs)	**69.9**	**70.7**	**71.5**	**72.3**	**72.9**	**357.4**
Debt raising costs	0.9	0.9	0.9	0.9	0.9	4.4
ARS*	2.4	2.4	2.4	2.5	2.5	12.4
Total opex	**73.2**	**74.0**	**74.9**	**75.7**	**76.3**	**374.1**

*A forecast of Ancillary Reference Services can be found in Chapter 13, Table 13.2

Governance

Review and approval

Our review objectives (see Purpose), particularly our objective to develop a plan that is capable of being accepted by customers and stakeholders underpins our approach by ensuring we adopt AER approved methodologies and take on board customer and stakeholder feedback.

The development and approval of our Final Plan is overseen by the Review Steering Committee (RSC) which comprises all members of the Executive Management Team and is led by the CEO.

The RSC is supported by a working group led by the General Manager People and Strategy, and comprising representatives from across AGIG.

Alongside the Final Plan We are required to submit information in response to a Regulatory Information Notice from the AER. This information is accompanied by a statuary declaration completed by the Chairman and requires certain information to be audited/reviewed by an independent auditor.

Forecasts

Our Final Plan uses a number of forecasts including for opex and capex, and demand.

Forecasts in our Final Plan must reflect that required by a prudent gas distributor, acting efficiently and in accordance with good industry practice to achieve the lowest sustainable cost of providing Reference Services to our customers.

More detail on specific forecasts and how they are developed is available in relevant sections of the Final Plan:

- Opex: Section 7.4
- Capex: Section 8.4
- Demand: Chapter 9.

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 the budget, in consultation with AGN, for each financial year;
- providing regular information on financial and other management issues; and
- reading meters and billing retailers.

In consideration for operating the networks, we pay 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.

Delivering efficient capital expenditure

We operate within a framework of external and internal controls which govern the way we plan, assess, procure and deliver capital works. This framework ensures we are making sound investment decisions for our customers, our stakeholders and our business. Our operating context is summarised in Figure 8.6 opposite.

Key Business Plans

We have a number of key business plans that 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 in line with our vision. Many of these are approved by the Office of the Technical Regulator (OTR) and the Essential Services Commission of South Australia (ESCOSA).

Our Safety, Reliability, Maintenance and Technical Management Plan (Safety Plan) is part of our overall approach to system management. It follows a continuous improvement cycle of Commit, Plan, Do, Check and Act, with the objectives of:

- maintaining a strong focus on safety and reliability in relation to the operation and management of our distribution network;
- ensuring suitable safety management systems are in place and operating to effectively manage and keep risks associated with the operation of our network to as low as reasonably practicable; and
- communicating relevant information related to the safe and reliable operation of our distribution network with our regulators.

Our Strategic Asset Management Plan (SAMP) and annual AMP are key parts of our Asset Management Framework. They outline our asset management strategies which are consistent with good industry practice.

Subordinate to the SAMP and AMP are:

- the Distribution Mains and Services Integrity Plan (DMSIP) which outlines our 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; and
- the Meter Replacement Plan (also known as the Gas Measurement Management Plan in South Australia) which details our compliance obligations and how this drives the forecast volume of meters to be replaced over the next AA period.

These business plans outline how we continually monitor, evaluate, plan and undertake asset integrity assessments to extend the remaining life, improve, replace, or where necessary, retire assets. This ensures efficient, reliable and safe operations of the network are maintained.

Financial governance

Our business planning doesn't stop with each AA period. We continually update our capex plans to respond to changing business needs.

A key part of our planning is the approval of the capex budget by the Board each year.

Once approved, projects are then managed and monitored through our capital delivery processes, this includes Executive Management Team review of key contracts before they are awarded.

We regularly report our expenditure performance against prior year spend and approved regulatory allowances. We also regularly review network performance, including through a series of key performance measures as an input into our planning process.

Our Delegation of Financial Authority covers all financial transactions within our organisation. It outlines the level of financial authority at each level within our organisation. Only the CEO has financial delegation to approve funds for unbudgeted initiatives, and only where it fits within the overall approved budget. This provides strong financial controls and governance in the delivery of capex.

Procurement Policy

All procurement activities are subject to our Procurement Policy and Purchasing Procedure (see Attachment 8.5). This ensures we carry out these activities in an consistent, effective, confidential and ethical manner. The policy also ensures we:

- Maximise cost savings;
- Mitigate risks associated with the provision of goods and services; and
- Achieve excellence in both operational and financial performance.

Internal Audit

Our internal audit function provides independent assurance that our risk management, governance and internal control processes are operated effectively.

Each year the Board approves an Internal Audit Plan. Independent external professional firms are engaged to deliver the audit reviews. Audit review outcomes, and any required actions, are presented to and agreed by the Audit Committee (a sub-Committee of the Board). This provides our directors and management assurance as to the existence and strength of the controls implemented.

Figure 8.6
Summary of our operating context

Legislation and frameworks

- National Gas Law
- National Energy Retail Rules
- Gas Act 1997
- Gas Regulations 2012
- Distribution Licence
- Gas Distribution Code
- Gas Metering Code
- Safety, Reliability, Maintenance & Technical Management Plan
- Industry Standards

Authorities

- Australian Energy Regulator (AER)
- Essential Services Commission of South Australia (ESCOSA)
- Office of the Technical Regulator (OTR)

Key Business Plans

- Vision
- Asset Management Plan
- IT Investment Plan
- Meter Replacement Plan
- Distribution Mains and Services Integrity Plan
- Leak Management Plan

8 Capital expenditure

IN THIS CHAPTER:

We are investing $579 million in the next AA period, which is 3% lower than current levels.

We are replacing 860 km of old cast iron, other low pressure and early generation plastic mains.

We will complete the replacement of all cast iron mains in the network, a significant safety milestone for our customers and our business.

Our network will grow as we connect around 39,000 new customers in the next AA period.

Our capex forecast is in line with current levels and will ensure we maintain our strong safety, reliability and service performance

The capex we incur is required to ensure gas is supplied in a safe and reliable manner and to support ongoing network growth and customer service

Consistent with prior AA reviews, our capex forecast has been determined using a bottom-up approach, with separate forecasts developed for our proposed expenditure on activities that will maintain and/or improve:

- public safety and service reliability;
- network growth; and
- customer service.

The application of the bottom-up approach has been informed by our Strategic Asset Management Plan (SAMP), risk management framework, regulatory obligations and projected network growth.

Our capex is forecast to be around $579 million in the next AA period, which is 3% ($20 million) lower than what we expect to incur in the current AA period (see Table 8.1). This is consistent with the $579 million proposed in our Draft Plan, but incorporates our decision to step away from reclassifying some overheads from capex to opex and further refinement of project scope and cost estimates.

Relative to the current period, our expenditure on growth and customer service are both expected to decrease, reflecting a small reduction in expected connection growth in the next period and a smaller meter replacement program.

The following sections provide further detail on our regulatory requirements, the forecasting method we have used and our capex forecasts for the next AA period. This chapter also provides

Table 8.1: Actual and forecast capex by priority ($million, 2020/21)

Priority	Current AA period	Next AA period	Drivers for change
Safety and reliability	388.3	389.0	✓ Start modification of transmission pipelines to allow inline inspection (ILI) ✓ Slightly lower mains replacement program
Growing the network	175.9	159.0	✓ Lower expected connection growth in the next period ✓ Mount Barker extension in 2020/21
Customer service	35.1	30.9	✓ Reduction in the number of periodic meter changes required
	599.3	**578.8**	

an overview of how we have performed in the current AA period and how we ensure the capex we incur is both prudent and efficient.

All numbers quoted in this section are expressed in 2020/21 dollars and include overheads and escalation, unless otherwise stated.

8.1 Regulatory framework

Our AA proposal must include:

- the forecast capex for the next AA period; and
- the capex incurred (or forecast to be incurred) in the current AA period.

Our forecast capex must reflect that required by a prudent gas distributor, acting efficiently and in accordance with good industry practice to achieve the lowest sustainable cost of providing Reference Services to our customers.[1]

Forecast capex must also satisfy various additional criteria,[2] including to:

- maintain and improve safety;
- maintain integrity;
- comply with our obligations;
- meet demand on the network;
- result in an overall economic benefit; or
- where additional revenue generated exceeds the associated costs.

Any forecast or estimate we provide must also be arrived at on a reasonable basis and represent the best forecast or estimate possible in the circumstances.[3]

[1] NGR 79(1)
[2] NGR 79(2)
[3] NGR 74

8.2 Customer and stakeholder engagement

We have developed our capex proposal in consultation with our customers and stakeholders (see Table 8.2).

Customers told us their top priorities are price/affordability, reliability of supply and maintaining public safety. Customers highly value our track record of performance for both reliability and public safety and expect this to continue.

We shared our proposed mains replacement program with participants in customer workshops. Customers were supportive of our investment approach to maintain current levels of reliability and safety.

Customers expect timely customer service by knowledgeable staff who demonstrate empathy and understanding in responding to queries or resolving issues. Customers and stakeholders are satisfied with our current customer service levels, but expect that digital communication channels will become increasingly available. We are proposing to invest in IT projects to improve online services for customers. This has been prepared in consultation with customers with a focus on web based services to keep costs low.

Our two reference groups were supportive of how we have developed our capex proposal. They were also keen to understand that our costs are efficient. We have demonstrated this in section 8.7 of this Chapter.

Table 8.2: Summary of customer and stakeholder engagement outcomes – Capital expenditure

Capital Expenditure

Customer and Stakeholder Feedback	Our Response
Stage 1 and 2 Engagement : Developing our Plans	
• Customers told us their top priorities are price/affordability, reliability of supply and maintaining public safety. • Customers told us they expect AGN to deliver high levels of public safety and feel that safety is currently well managed. • 92% customer support to maintain current levels of public safety and 96% customer support to maintain current levels of reliability • Stakeholders highlighted the importance of converting to polyethylene pipes and replacing cast iron mains for safety, reliability, to minimise gas losses and to prepare for the future. • Customers are interested in the supply chain and lifecycle of the mains. • Customers and stakeholders were keen to understand whether any additional expenditure would be required in readiness for hydrogen blending. • Stakeholders are keen to ensure that our costs are efficient, and that we can demonstrate this. • Stakeholders were comfortable with the preliminary expenditure proposals presented to SARG and RRG in February 2020.	• Our capex proposal includes investment at levels required to maintain current standards of reliability, public safety and customer service. • Our totex forecast (combined opex and capex) for the next AA period is consistent with the levels we expect to incur in the current AA period. • Our capex forecast has been developed using previously approved regulatory methodologies. • We provided information to customers on the lifecycle of mains. • We are not proposing any additional expenditure in relation to 'hydrogen readiness' as the completion of our mains replacement program will do this while focusing primarily on safety outcomes.
Stage 3 Engagement : Draft Plan Consultation ⇨ Do you support our approach to forecasting capex, including our approach to mains replacement in the next period? ⇨ Is there sufficient information to understand our proposals and the basis of the costs included in our capex forecast? Is there any other specific information that would assist in the assessment of our proposal?	
• 96% of customers supported investment proposals in our Draft Plan to maintain current levels of reliability, safety and customer service. • Customers and stakeholders welcomed the proposed completion of the cast iron mains replacement program including the safety and operational benefits (e.g. hydrogen ready) this will deliver. • SARG and RRG indicated support for our proposed capex investment.	• We agreed to continue to refine our capex proposal for inclusion in our Final Plan.
Stage 4 Engagement : Refining our Plans	
• SARG and RRG broadly support our capex proposal to maintain current levels of reliability, safety and customer service.	• Our capex proposal is included in Chapter 8 of this Final Plan.
Final Plan Outcome	
✓ Our capex proposal delivers against customer expectations that current levels of reliability and safety are maintained. Customers and stakeholders support the approach and levels of capital expenditure included in our Final Plan. Customers and stakeholders supported the ongoing delivery of our mains replacement program, noting the significant safety milestone in completing the cast iron mains replacement program. This Final Plan provides supporting information on capex and evidence of our governance arrangements that support cost being efficient.	

8.3 Our capex over time

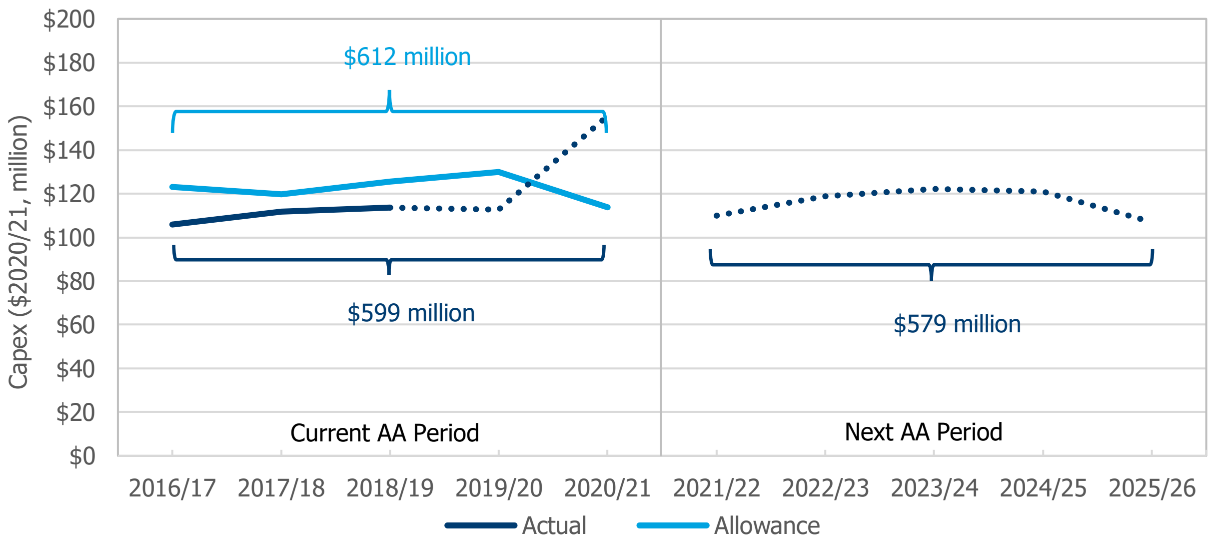
Our capex is driven by our safety and environmental obligations, the requirements and expectations of our customers and the age, performance and condition of our assets.

Figure 8.1 shows our actual and forecast capex over the current and next AA periods. Overall, we are forecasting a 3% decline in capex compared to what we are currently spending. The increase in the last year of the current period (2020/21) is because of the proposed extension to Mount Barker (Section 8.8.6) and delays in two IT projects (GIS and mobility, Section 8.8.5).

Our forecast of $579 million for the next AA period incorporates our decision not to move some of our capitalised overheads to opex in the next AA period. This is a change from the position in our Draft Plan. While we consider the proposal to shift some of the overheads from capex to opex has merit, other updates to inputs since publication of the Draft Plan resulted in upward pressure on price. To mitigate this impact, and to deliver a price outcome in line with our Draft Plan, we have elected not to pursue the initiative. This reflects the already noted finding that price is an important priority for our customers, particularly in the current circumstances surrounding the COVID-19 pandemic.

On a like-for-like basis (i.e. including the same capitalisation of network overheads) our Final Plan capex is $23 million lower than what we proposed in our Draft Plan. The reductions are a result of refining our cost estimates and the scope of other distribution projects to be delivered in the next AA period.

Figure 8.1: 10-year capex



8.4 How we develop our capex forecast

Our capex forecast for the next AA period has been developed using a bottom-up approach, with the cost of undertaking each project estimated separately. This section describes how we develop the key elements of our capex forecast, being the proposed activities and forecast costs, in more detail.

8.4.1 Determining our investment priorities

Some of our forecast reflects the continuation of existing programs of work, such as our mains and meter replacement programs. Others are new projects, such as the modification of some of our transmission pipelines to allow for in-line inspections (ILI) and digital customer service projects.

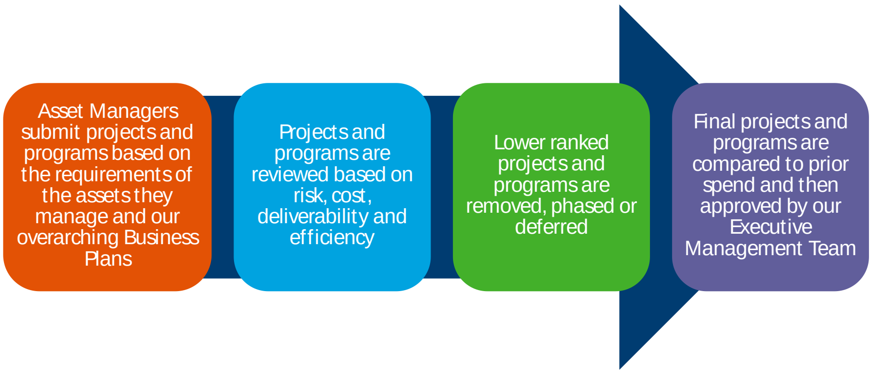
The process we use to identify the projects to be carried out is shown in Figure 8.2.

As this figure shows, potential projects are identified by asset managers having regard to our overarching Business Plans, such as our Strategic Asset Management Plan (SAMP), risk management framework, regulatory obligations, projected network growth and the full lifecycle cost of distributing natural gas.

The proposed projects are then subject to review, risk ranking and phasing based on lifecycle cost, deliverability and efficiency.

Full business cases are then developed for the higher ranked projects that are proposed to be delivered within the regulatory period. This allows a more detailed assessment to be undertaken of the options to

Figure 8.2: Summary of capex planning process



address the identified problems. Our assessment and selection of the preferred option considers the costs of the options, the expected risk reduction or benefit of the options, any relevant feedback from our customers and stakeholders, alignment with our vision and the consistency of the selected option with the relevant provisions in the NGR. Lower ranked projects, on the other hand, are deferred.

Our SAMP summarises our total program of works over the next AA period and is provided as Attachment 8.2 of this Plan.

8.4.2 Forecasting efficient costs

Our forecast costs must be efficient, reasonable and represent the best possible forecast or estimate in the circumstances.

We have two categories for forecasting efficient capex costs to ensure these requirements are met. They are:

- Unit rate categories: for high volume work with limited variation in scope (e.g. new connections) where the forecast cost is based on a unit rate price multiplied by the volume of activity to be undertaken in the period; and
- Non-unit rate categories: low volume, discrete projects where the forecast cost is built up based on the scope of work outlined within the project or program.

The unit rate categories include:

- Growth capex:
  - Mains – new estates, existing homes and industrial and commercial (I&C) customers;
  - Services – new homes, multi-user sites, existing homes and I&C customers; and
  - Meters – new domestic and I&C customers' meter connections;
- Meter Replacement – periodic meter change (PMC) (domestic and I&C meters); and
- Mains Replacement – general block replacement of cast iron, unprotected steel and other materials (normal and high-density areas), High-Density Polyethylene (HDPE) replacement (by class), multi-user service renewals, piecemeal mains replacement and inline camera inspections.

Unit rate prices are based on a range of information sources including:

- tender or contract information which has been tested through a competitive market process;
- current actual rates or a historical average rate (i.e. over the last three years of the current AA period) achieved for similar work; and
- both internal and external specialist engineering estimates.

We have provided the AER with detailed information on our forecast unit rates for the next AA period in a confidential attachment to this Plan. This attachment outlines the contracts we have in place, the current unit rates for these activities and the basis on which unit rates for the next AA period have been calculated.

The non-unit rate categories include augmentation, IT, growth to new areas, regulators and valves, telemetry, other distribution and other non-distribution projects and programs. Each project or activity is supported by a business case.

Forecast costs for these works may be based on tender or contract information, current actual or historical costs for similar works or specialist engineering estimates.

All capex business cases are provided in Attachment 8.8 to this Plan.

8.5 Our capex priorities in the next AA period

The key capex priorities in the next AA period are:

- Safety and Reliability;
- Growing the Network; and
- Customer Service.

As Figure 8.3 shows, 67% of our forecast capex is focused on maintaining safety and reliability, which are both top priorities for our customers.

8.5.1 Safety and reliability

In the next AA period, we propose to invest $389 million on projects and programs that will maintain our strong public safety and reliability performance. This is $2 million more than the $387 million in our Draft Plan.

The largest of these projects and programs is our mains replacement program where we will replace a further 860 km of old cast iron, unprotected steel and first-generation plastic pipes which are more susceptible to leaks, cracks and breaks.

By the end of the period we will have removed all remaining low pressure cast iron from our network. This achieves a very significant safety milestone for our customers and our business and follows completion of the Adelaide CBD mains replacement program in the current period.

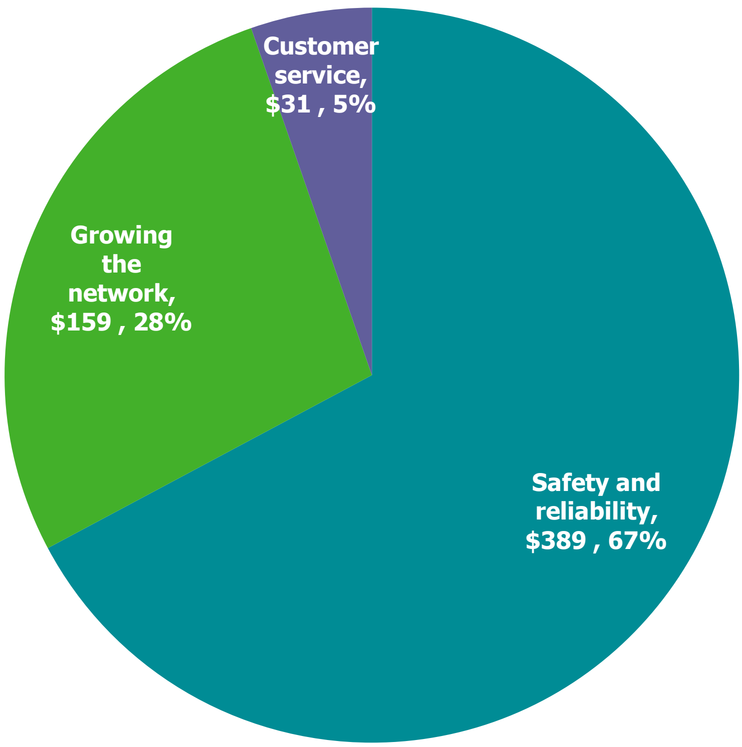
We will continue integrity dig-ups and surveys, and start modifying our higher-pressure transmission mains to allow ILI. We will replace end-of-life regulators, valves, telemetry and cathodic protection equipment.

We will also invest in the ongoing maintenance and upgrades of our core business systems to ensure they are current, fit-for-purpose, resilient to cyber threats and continue to support the requirements of our business efficiently.

8.5.2 Growing the network

We propose to invest $159 million in the next AA period on projects

Figure 8.3: Forecast capex by priority ($million, 2020/21)



and programs that will grow our network. This is $1 million less than the $160 million in our Draft Plan.

This includes laying reticulation mains and services and installing meters to connect around 39,000 new residential and industrial customers to our network. We will also augment our network in both the north and the south extremities to support the continued growth we have seen in these areas and to ensure service levels are maintained for existing and new customers in these growing areas.

8.5.3 Customer service

In the next AA period we propose to invest $31 million on projects and programs to continue to meet the service expectations of our customers. This is $1 million less than the $32 million in our Draft Plan.

This includes our meter replacement program, which will replace ageing meters to ensure accuracy of customer billing is maintained, and investment in our IT systems that support our customer service functions.

In line with feedback from our customers and stakeholders, we have refined our digital customer experience initiative, which will provide more digital services and a greater variety of communication channels to our customers. This will bring our digital services more in line with industry standards and improve the service experience for our customers.

8.6 Capex drivers in the next AA period

The following sections provide further detail on the capex drivers and activities we propose to undertake in the next AA period.

The activities under each of these areas are supported by our business plans and individual business cases. These business plans and business cases assess the options considered to address the identified issue, the estimated cost of each option, the untreated and residual risk each option would result in and alignment with the capex requirements of the NGR and our vision (see Attachment 8.8).

8.6.1 Mains replacement

The integrity of our distribution mains and services remains a key focus in the next AA period. Mains replacement (and associated works) is the single most important activity we undertake to ensure public safety.

We will invest $294 million ($2 million more than the $292 million in our Draft Plan) to:

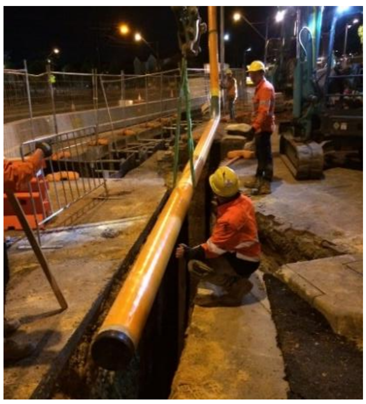
- complete the replacement of all remaining low-pressure cast iron, unprotected steel and other mains – a further 558 km in addition to the 405 km we will have replaced in the current AA period. All low and medium pressure cast iron and unprotected steel mains will be removed from the network by the end of the next AA period which represents a significant safety milestone;
- complete the replacement of all remaining high-risk early generation plastic piping (HDPE 250) – a further 14 km in addition to the 291 km we will have replaced in the current AA period;
- undertake inline camera inspections and reinforcement on 316 km of high-risk early generation plastic piping (HDPE 575) where possible, and replace 288 km of high-risk early generation plastic piping (HDPE 575) where inline camera inspection and reinforcement cannot be completed. This follows on from 357 km of replacement and 310 km of inline inspection on HDPE 575 mains in the current AA period.

In total we will replace 860 km of mains in the next AA period.

While this is a lower volume than the 1,052 km we will complete in the current AA period, we are forecasting a higher average cost across the program. This is due to:

- new external requirements (such as the requirements of other utilities when undertaking work near their assets) which have introduced additional costs to our mains replacement activities; and
- the fact we are replacing a larger proportion of smaller diameter HDPE mains, which requires direct laying of the new pipe, compared to the lower cost technique of pipe insertion used more consistently in the past. Direct laying of new pipe allows for

Figure 8.4: Installation of transmission steel pipeline, Morphett Rd, Oaklands Park, December 2018



an increase in pressure and capacity.

Further detail on mains replacement and associated activities can be found in Attachment 8.3 Distribution, Mains and Services Integrity Plan (DMSIP).

While safety driven, the mains replacement program has the additional benefit of future-proofing our network given our new plastic pipes are hydrogen-ready.

8.6.2 Meter Replacement

Customer meters measure the amount of gas delivered, which forms a key component of each gas bill. We undertake periodic meter changes and associated activities to test and replace old meters and ensure meter accuracy is maintained. Based on the age and performance of our current fleet of meters, and the metering accuracy requirements we must achieve, we forecast to replace over 93,000 meters during the next AA period at a total cost of $21 million. This is $2 million higher than the $19 million in our Draft Plan and reflects updated actual cost information for these activities.

Overall, our expenditure on periodic meter changes in the next AA period is forecast to be lower than what we are spending in the current AA period. This is due to a lower volume of replacements required consistent with our obligations.

We have used an approach to forecasting consistent with that in the current AA period to determine the number of periodic meter changes required. This approach considers the age and condition of the current stock of domestic and commercial meters in our network and, therefore, volumes can vary between AA periods.

Our Meter Replacement Plan is provided in Attachment 8.4 of this Plan.

8.6.3 Augmentation

We are always monitoring the pressure and performance of our network. As the number of connections to our network grows, we can see a deterioration in pressure and performance. We use this information to determine areas where our network is becoming constrained and requires augmentation. Augmentation supports the continued growth of the network and ensures service levels are maintained for existing customers in growing areas.

We are seeing continuing strong growth in the north and south of our network and forecast two augmentation projects will be required in the next AA period.

In the north we will invest $8 million (no change from our Draft Plan) to build a new high-pressure main and gate station in Gawler. This will provide a new connection into the SEA Gas transmission pipeline, increasing the capacity of the northern network to support continued growth in the area. This option was preferred to trunk main duplication or reactive works as it will enable new developments to connect without adversely affecting customers in the Willaston area. This project will support growth in the outer-northern parts of the network for more than 20 years at the lowest sustainable cost.


Seaford Meadows development, image courtesy of UDIA SA

In the south we will invest $3 million (no change from our Draft Plan) to duplicate our high-pressure main from McLaren Vale to Aldinga, providing increased capacity for the growing southern network. This follows on from supply to McLaren Vale in 2016, a high-pressure extension in 2017 and a transmission extension and new regulator in 2018. This option will support continued load growth in the outer-southern metropolitan area without impacting existing customers' supply, at the lowest sustainable cost.

8.6.4 Telemetry

Telemetry allows for the monitoring and control of our network remotely through information captured from and transferred to equipment in the field. In the next AA period we will invest $2 million (no change from our Draft Plan) to replace end of life Supervisory Control and Data Acquisition (SCADA) equipment and install additional pressure monitoring points to ensure we can continue to collect appropriate pressure information from the network as it grows and changes.

8.6.5 IT System

Our IT systems support several core functions, including billing, finance, asset management, asset operations, regulatory reporting and customer service. In the next AA period we will invest:

- $16 million in maintaining and upgrading our current applications to ensure they remain current, fit-for-purpose and resilient to cyber threats;
- $15 million in rationalising our IT applications and infrastructure across AGIG;
- $3 million on an Asset Investment Planning Tool, which will allow incorporation of a broader range of information sources into scenario planning and investment decision making; and
- $2 million to deliver more customer services digitally in line with those provided by other businesses and the expectations of our customers.

In total, our IT capex program is $36 million. This is $3 million higher than the $33 million in our Draft Plan and $5 million below the $42 million we forecast we will invest in the current period.

The increase from the Draft Plan is due to refinement of the scope and cost of works in rationalising our IT applications and infrastructure across AGIG. More detailed information is provided in our IT Investment Plan (Attachment 8.6) and the individual business cases (Attachment 8.8).

8.6.6 Growth

We extend our network and lay new reticulation mains, services and install meters to connect new customers to our network where the expected revenue exceeds the cost of the capital expenditure.

We will invest $147 million to connect around 39,000 new residential and business customers over the next AA period. This is $2 million less than the $149 million in our Draft Plan and reflects updates to both our connections forecast and latest actual cost information.

We will connect new homes and businesses in greenfield and in-fill developments, as well as existing homes and businesses connecting to our network for the first time. This includes connecting customers for the first time in Mount Barker and two extensions of our network to the Concordia residential estate ($3 million) and Kingsford Smith industrial estate ($3 million) – which are both located in outer northern Adelaide.

Our approach to forecasting the number of new connections is explained in Chapter 12.

8.6.7 Other distribution system assets

We will invest $62 million on other distribution system assets. This is $6 million less than the $68 million forecast in our Draft Plan.

The largest project for the next AA period is $36 million to start modifying our higher-pressure transmission mains to allow inline inspection in accordance with accepted good industry practice.

We will also continue integrity dig-ups and surveys, replace end-of-life regulators, valves, telemetry and cathodic protection equipment.

The reduction in total costs from our Draft Plan reflects that we plan to:

- complete our overpressure risk reduction scope of work (which aims to bring older assets in line with new design standards) over ten years, rather than five;
- have updated cost estimates across all projects; and
- removed our meters in buildings and carports from our capex forecast to align with the AER's preferred regulatory treatment for these works to be opex. We will continue to eliminate high-risk meters located in buildings and carports within our forecast opex for the next AA period.

8.6.8 Other non-distribution system assets

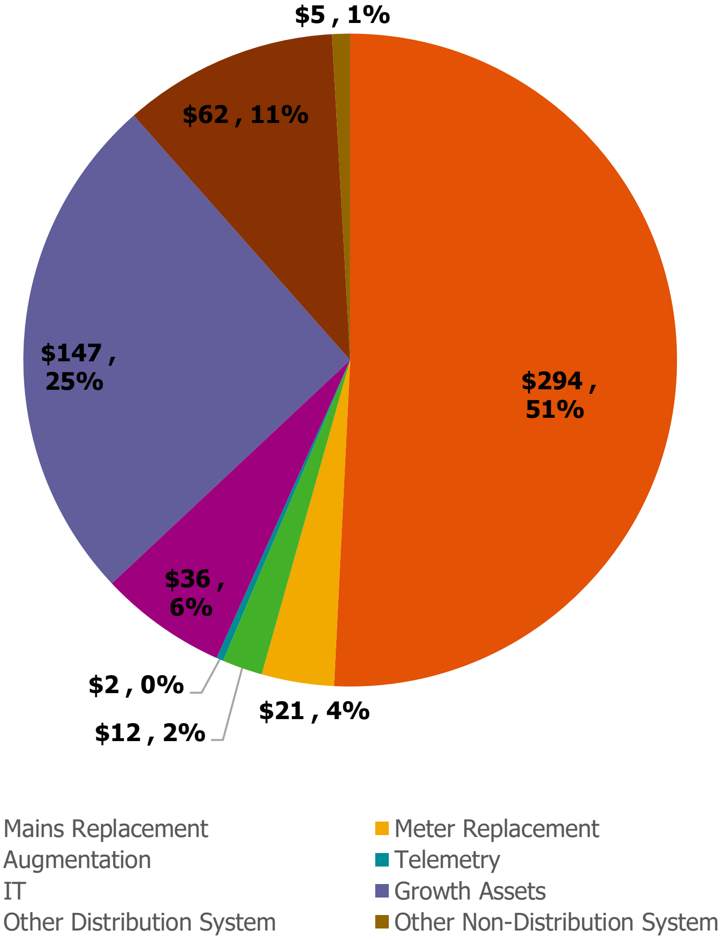
We will invest $5 million ($1 million more than the $4 million in our Draft Plan) on other non-distribution system assets in the next AA period. This includes replacement of small plant and equipment based on the age and condition of these assets, as well as any changing business requirements. The increase reflects updated cost estimates as well as the reversion back to our current approach to capitalisation of overheads.

8.6.9 Summary of our capex forecast by driver

Figure 8.5 provides a breakdown of our forecast capex by driver. As noted above, a significant proportion of our capex in the next AA period is accounted for by our mains replacement program (51%) and the investment required to support the projected growth in the network (25%).

The remainder is accounted for by projects and programs that will ensure we continue to maintain our strong safety, reliability and service performance.

Figure 8.5: Capex by driver over the next AA period ($million, 2020/21)



8.7 Our capex priorities in the current AA period

In total, we expect to invest $599 million by the end of this AA period. This is $11 million less than the $610 million we forecast in our Draft Plan and reflects updated actuals for 2019/20 and refinement of plans for 2020/21.

Like our capex proposal for the next AA period, our capex in the current AA period have aligned with our customers' priorities of:

- safety and reliability;
- growing the network; and
- customer service.

Figure 8.6 provides a breakdown of the amount of capex we expect to have incurred against each of these priorities. As this figure shows, 65% of our capex in the current AA period is focused on safety and reliability, which together with price/affordability reflect the top priorities of our customers. This allocation of our capex in the current AA period aligns with the allocation forecast for the next AA period (Figure 8.3), reflecting the business-as-usual nature of our plan.

8.7.1 Safety and Reliability

At the end of the current AA period we will have invested $388 million (forecast to the end of the period) on projects and programs that will enable us to maintain our strong safety and reliability performance.

We have proactively replaced 801 km of old cast iron, unprotected steel and first-generation plastic pipes up to the end of April 2020, with a further 251 km planned for the next 14 months. We will complete our mains replacement program in the Adelaide CBD, removing the extreme risk associated with these mains as agreed with the OTR.

Completing the mains replacement program in the Adelaide CBD represents a significant safety milestone for our customers and our business. We are on track to deliver the full volume of mains replacement approved by the AER for the current AA period.

We have undertaken integrity dig ups and surveys, replaced end of life regulators, valves, telemetry and cathodic protection equipment. We have also undertaken maintenance and upgrades of our core business systems to ensure they are current, fit-for-purpose, resilient to cyber threats and continue to support the requirements of our business efficiently.

8.7.2 Growing our network

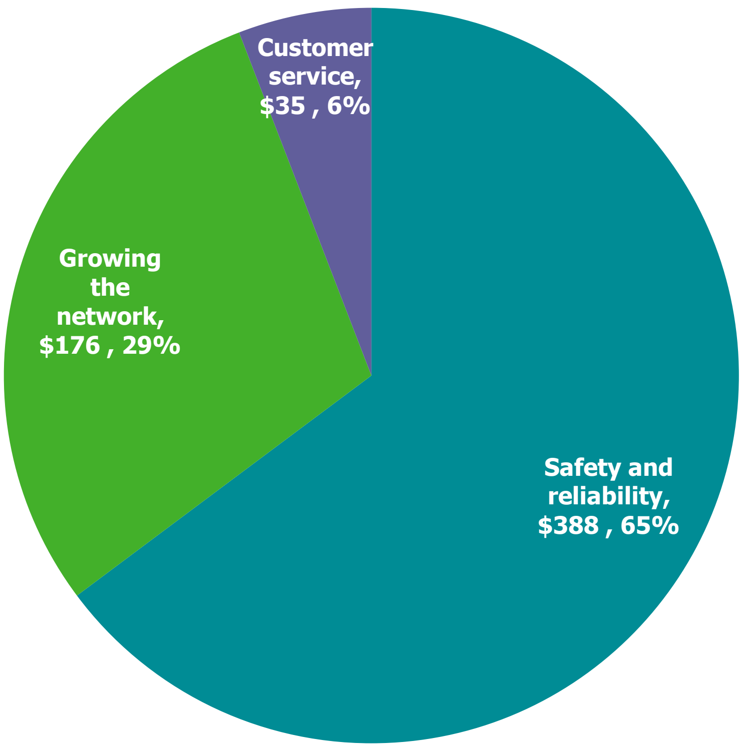
We will have invested $176 million (forecast by the end of the period) on connecting over 25,000 new residential and industrial customers to our network at the end of June 2019, with a further 15,000 expected for the last two years of the period.

We have completed the first stage of planned augmentations in the southern metro network to support residential growth in Seaford, Aldinga and McLaren Vale, as well as network augmentation to support development in Bowden (just north west of the Adelaide CBD) and Adelaide CBD East.

8.7.3 Customer service

We will have invested $35 million (forecast by the end of the period) on projects and programs to deliver a service experience that continues to meet the

Figure 8.6: Current AA period capex by priority ($million, 2020/21)



expectations of our customers. This includes $25 million on periodic meter changes for almost 140,000 meters under our meter replacement program.

8.8 Capex drivers in the current AA period

The following sections provide further detail on the capex drivers and activities we have undertaken in the current AA period.

8.8.1 Mains replacement

Our mains replacement program is the largest driver of our capex in the current AA period, and as outlined above will remain a key focus in the next AA period. It is the single most important activity we can undertake to ensure public safety.

As agreed with our technical regulator, the OTR, we are on track to complete the replacement of 346 km of low pressure cast iron, unprotected steel and other mains, including all old CBD mains by the end of June 2021. This volume of activity is also aligned with our commitment to the AER in our last AA submission to replace a total of 351 km of these materials (the small variance reflects the actual inventory of mains on 1 July 2016).

We will also have completed our medium pressure trunk CI/UPS replacement, in line with our commitments, totalling 59 km.

We are also replacing early generation plastic pipes which have a history of cracks and breaks. By the end of the current period, we will have replaced 291 km of HDPE 250 and 357 km of HDPE 575 mains, by the end of June 2021. This is in line with our commitment to proactively replace a total of 654 km of these materials which was made to our technical regulator, the OTR, and the AER in our last AA submission.

Furthermore, we will have completed inline camera inspections and reinforcements on 310 km of HDPE 575 mains which have a diameter which supports this treatment. This will extend the life of these mains for an estimated ten years.

Figure 8.7: Direct bury of new gas mains, Wakefield Street, Adelaide, August 2016

More detail on our mains replacement activities is provided in our DMSIP at Attachment 8.3.

8.8.2 Meter Replacement

We undertake periodic meter changes to replace older meters and ensure meter accuracy is maintained. Based on the age and performance of our current fleet of meters, and the metering accuracy requirements we must achieve, we have replaced around 106,000 meters to June 2019 and forecast we will have replaced a further 34,000 meters by the end of June 2021 at a total cost of $25 million over the five years. This is slightly above our allowance of $24 million due to a higher actual unit rate cost incurred for meter replacements. This higher unit rate cost is driven by a greater proportion of new compared to refurbished meters required to be installed (where new meters are more expensive than refurbished meters) and an increase in the ancillary works (such as repairs to meter boxes) undertaken concurrently with the meter replacement. This has the benefit of addressing these issues on the spot and reducing repeat visits.

More information on meter replacement in the current period can be found in our Meter Replacement Plan (Attachment 8.4 of this Plan).

8.8.3 Augmentation

We augment our network to ensure we can support continued growth while also maintaining current service levels for existing customers in growing areas.

Figure 8.8: New Industrial and Commercial connections at the Vista development in Seaford. Photos courtesy of the UDIA SA.

At the end of the current AA period we will have invested $13 million, including the first stage of planned augmentations in the southern metro network to support residential growth in Seaford, Aldinga and McLaren Vale, work at Bowden and upgrades to Adelaide CBD East.

8.8.4Telemetry

By the end of the current AA period we will have invested a little over $1 million to replace end of life SCADA and pressure monitoring equipment to ensure we can continue to effectively control and monitor our network remotely through information captured from and transferred to our assets in the field.

8.8.5IT System

Our IT systems support a number of core business functions including billing, finance, asset management, asset operations, regulatory reporting and customer service.

In the current AA period we have invested a total of $42 million (by the end of the period), which has been focused on nationalising and consolidating our major network IT applications, leveraging the capability of these systems through our application renewal program and building our digital capability. This is below our approved allowance for the period as we:

- have been able to achieve a "current minus one" version methodology for our applications with less frequent upgrades than what we had initially planned; and
- were able to leverage the Business Intelligence platform implemented by APA which means the infrastructure costs are spread over a larger base.

While expenditure in relation to the GIS and Mobility projects has been delayed, we are planning to complete the full scope of works, at a lower cost than was approved, by the end of June 2021. More information is provided in our IT Investment Plan at Attachment 8.6.

8.8.6Growth

In line with our vision of delivering profitable growth, we will have invested $163 million to connect around 40,000 new residential and business customers to our distribution network over the current AA period. This includes new homes and businesses in greenfield developments close to our network, new homes and businesses within our network (infill), existing homes and businesses which are connecting to the gas network for the first time, and extensions of our network to:

- McLaren Vale to the south of Adelaide;
- Two Wells to the north of Adelaide; and
- Mount Barker to the east of Adelaide.

8.8.7 Other distribution system assets

We will have invested $52 million on other distribution system assets in the current AA period. This includes completing integrity dig ups and surveys, replacing end-of-life regulators, valves, telemetry, stopple and cathodic protection equipment.

8.8.8 Other non-distribution system assets

We will have invested $4 million on other non-distribution system assets in the current AA period. This includes replacement of small plant and equipment based on the age and condition of these assets, as well as any changing business requirements.

8.8.9 Summary of our capex in the current AA period by driver

Figure 8.10 provides a breakdown of our capex in the current AA period by driver. As noted above, a significant proportion of our capex in the current AA period is accounted for by our mains replacement program (50%), the investment required to support network growth (27%), replacement and refurbishment of other distribution network assets (9%) and investment in IT (7%).

The remainder is accounted for by projects and programs that are designed to ensure we continue to maintain our strong safety, reliability and service performance.

Figure 8.9: Capex in the current AA period by driver ($million, 2020/21)

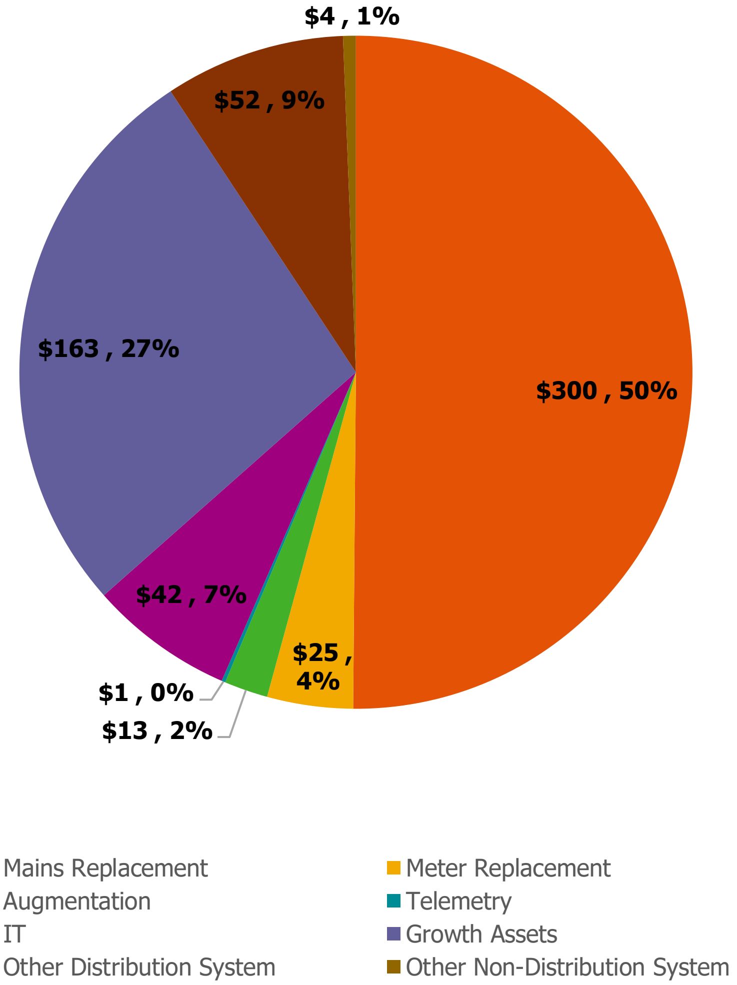


Figure 8.10: (from left) Isolation and bypass on a live steel gas main, South Road, Hindmarsh, April 2017; Cut and capping low pressure cast iron main, Grote Street, Adelaide CBD, October 2016

Table 8.3 below compares our capex in the current AA period with what we propose to incur in the next AA period by capex driver. It shows that our proposed level of expenditure is consistent with what we expect to incur this period reflecting the business-as-usual nature of our plan.

For our largest single program – mains replacement – we are expecting lower expenditure in the next period reflecting a lower volume of mains replaced. We are also projecting a decline in growth capex reflecting the timing of the Mount Barker extension occurring this period as well as lower meter replacement expenditure related to lower volumes of meters required to be replaced. These declines are offset by an increase in other distribution system capex, driven by our transmission modifications for ILI project, as well as increases in our augmentation, telemetry and other non-distribution system capex.

Table 8.3: Forecast capex by driver ($ million, 2020/21)

Driver	Current AA period	Next AA period	Key activities
Mains Replacement	300.4	294.0	• Complete replacement of all low-pressure mains, including all cast iron mains • Complete camera inspections and reinforcement of first-generation plastic mains where possible and prioritised replacement of high risk mains which cannot be inspected by camera
Meter Replacement	24.7	20.7	• Periodic replacement of end of life customer meters
Augmentation	12.6	11.5	• Upgrades to the eastern Adelaide CBD network • High pressure mains extension and then duplication in the southern metro network • New gate station and high pressure main in the northern metro network
Telemetry	1.1	2.0	• Replacement of end of life telemetry equipment • Install small number of additional pressure monitoring equipment
IT System	41.6	36.5	• Maintain and rationalise existing core business systems • Deliver an enhanced digital customer service
Growth	163.3	147.4	• Connect new residential and business customers to our network • Extend the distribution network to new areas where it is economically viable to do so
Other distribution system	51.9	61.5	• Undertake integrity dig ups and repairs • Replace end of life valves, regulators, stopple and cathodic protection equipment • Undertake overpressure risk reduction measures for I&C customers based on new design standards • Start to modify transmission mains for inline inspection
Other non-distribution system assets	3.7	5.1	• Replacement and repairs of small plant and equipment
Total	**599.3**	**578.8**	

8.9 Summary

Our capex in the next AA period will ensure we:

- maintain our high levels of public safety and reliability as expected by our customers;
- connect new customers to our network where it is economically viable to do so; and
- continue to provide the level of customer service that our customers require and expect.

The projects and programs we intend to deliver are described below.

- Continuing our mains replacement program, specifically we will;
    - complete the replacement of old cast iron, unprotected steel and other low-pressure pipes (558 km, $178 million), representing another significant safety milestone for our customers and our business;
    - the mains replacement program has the additional benefit of future-proofing our network given our new plastic pipes are hydrogen-ready;
    - continue replacing the highest risk, smaller diameter first generation plastic pipes (302 km, $94 million);
    - complete inline camera inspections across larger first-generation plastic pipes (316 km, $9 million);
    - renew 457 multi-user services ($8 million); and
    - undertake reactive replacement of services required outside of the annual mains replacement program ($6 million).
- Continuing our meter replacement program ($21 million) to ensure accurate gas measurement and billing for our customers.
- Augmenting the southern and outer-northern metropolitan networks ($12 million) to support the continued growth in those areas and maintain reliability for existing customers.
- Replacing end-of-life telemetry equipment ($2 million) which is critical to operating and monitoring our network.
- Ensuring our IT systems are current and fit-for-purpose by maintaining and undertaking regular upgrades of our current applications ($16 million), rationalising our applications and infrastructure across AGIG ($15 million), and implementing new technologies for our business and our customers where there is an overall benefit or service improvement ($5 million).
- Growing the network to new areas ($6 million) where it is economically viable to do so, and connecting around 39,000 new residential and business customers to our network over the five years to June 2026 ($141 million).
- Modifying our ageing transmission pipelines to allow for inline inspections ($36 million) and other distribution system works, such as replacement of valves, over pressure risk reduction, cathodic protection and dig up repairs ($25 million).
- Replacing and refurbishing of small plant and equipment ($5 million).

These projects and programs are broadly aligned to our track record over the current period with our forecast capex for the next AA period being $20 million below the actual forecast for the current period.

Mains replacement costs are slightly lower because of a reduction in the kilometres to be replaced, and growth to new areas is lower. However, we are investing more in other distribution system capex to deliver our new transmission pipeline modification for the ILI initiative, which will enable conformance with accepted good industry practice integrity assessment for transmission pressure pipelines.

The projects and programs outlined will deliver the high levels of public safety and reliability valued by our customers, grow our network (ultimately leading to lower prices for all of our customers) and ensure we continue to provide customer service that meets the expectations of our customers.

9 Capital Base

IN THIS CHAPTER:

Our capital base reflects the value of past investments that we have made in the network, but not yet recovered from our customers.

We are not at this stage proposing substantive changes to the economic lives of our assets in response to the energy transition – while there are risks that need to be addressed over time our assessment suggests it is better to wait until the subsequent AA period before acting.

This chapter discusses the movements in our capital base in the current and next AA periods.

We are required to adjust our capital base for capex, depreciation and inflation using actual information over the current AA period and forecast information over the next AA period. We estimate that the value of our capital base at the end of the next AA period (30 June 2026) will be around $2.1 billion.

9.1 Regulatory Framework

We are required to adjust our capital base to reflect capex (net of any amounts contributed by our customers), inflation and depreciation. We are also required to remove the value of any assets that have been sold and reflect the reuse of redundant assets in the current AA period.[1]

Our forecast of depreciation is required to be set:[2]

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

9.2 Customer and stakeholder engagement

Customers and stakeholders were keen to understand the longer term future of gas - what this means in the context of decarbonisation of the energy system, and what this means for customers and their bills given price and affordability is their top priority.

Customers and stakeholders expressed a strong interest in understanding more about renewable gas and the opportunities for gas to be decarbonised.

In July 2019 we held a dedicated stakeholder information session to support our stakeholders understand what was happening in the industry, across Australia and overseas. We discussed the range of hydrogen projects underway, technological advances, Australia's National Hydrogen Strategy, Government policy and Gas Vision 2050.

Similarly at customer workshops, customers were very keen to understand the potential for renewable gas and were keen to

[1] NGR 78
[2] NGR 89

learn more about Hydrogen Park South Australia.

We discussed the approach to determining our regulatory capital base with our reference group members at our meetings in December 2019 and throughout the first half of 2020 (see Table 9.1). As part of the discussion, stakeholders agreed that there is currently some uncertainty around the future of gas, but also that there is currently good momentum around hydrogen.

With the support of stakeholders, our Draft Plan did not include a proposal to shorten the economic life of our assets. We provided modelling to SARG and RRG members of the price impact of shortening asset lives in the next and/or the subsequent regulatory periods.

Stakeholders agreed that AGN should ensure there is adequate information available before pursuing shortening of asset likes, which will likely become evident during this coming AA period. This includes information around the success of the current range of pilot projects underway across Australia and the extent of policy support for blending hydrogen into gas networks.

Stakeholders also noted that AGN had considered the price impact of any change to depreciation in the next and subsequent AA periods.

We have engaged with CCP24 on the issue of uncertainty of the future of gas distribution networks. We appreciate the ongoing discussion as we continue to consider new information and changes to Government policy as they come into play, so that we can make decisions in the best interests of consumers.

Table 9.1: Summary of customer and stakeholder engagement outcomes – Capital base

Capital Base

Customer and Stakeholder Feedback	Our Response
Stage 1 and 2 Engagement : Developing our Plans	
• Stakeholders acknowledged the complexities around the future of the network given the ongoing decarbonisation of energy supplies, particularly how this could affect the economic life of gas assets/networks and therefore depreciation. • Stakeholders are keen to understand the future of renewable gas, such as hydrogen, noting hydrogen projects in South Australia and other states. • Stakeholders acknowledged that AGN is proposing to determine depreciation in accordance with the approach approved by the AER for AGN's Victorian networks, including by removing from the capital base those mains that have been replaced.	• There are a range of potential pathways for the decarbonisation of energy supplies. We see a future for our gas distribution business through advances and investment in renewable gases. • We proposed to continue to apply the asset lives approved by the AER for the current AA period. • We have applied the same approach to that approved by the AER for our Victorian network whereby mains that have been replaced are depreciated by the end of the next AA Period.
Stage 3 Engagement : Draft Plan Consultation ⇨ Do you have any comments on our proposed approach to adjust our capital base over the current and next AA periods, including how we have taken into account our mains replacement program? ⇨ Do you consider that the RBA-based approach will produce better forecasts of inflation relative to the Bond Breakeven approach? Are there any other approaches to forecasting inflation that should be used/considered?	
• SARG and RRG members are supportive of the approach to consider reviewing asset lives for the subsequent AA period on account of both price impact and uncertainty if the future of the gas network in a low carbon economy is not clearer by that time. • A stakeholder queried whether AGN had done modelling on reducing asset lives in the next period to address the uncertainty of the future of gas networks, and the potential impact on price. • CCP24 put forward alternate options for considering and managing stranded asset risk for discussion. • One stakeholder questioned the residual cost of the mains replacement program and the inclusion of this cost in the depreciation allowance.	• Regarding the transition underway in the energy sector, we provided stakeholders with a high-level indication of the price impacts of adjusting economic lives of assets today or waiting until the next period. • We advised we are not proposing substantive changes to the economic lives of our assets at this stage, noting that our assessment suggests it is better to wait until the subsequent AA period before acting. This includes by waiting to see whether current hydrogen pilot projects are successful and if there is policy support for renewable gas. • We provided additional information regarding mains replacement at our May 2020 SARG/ RRG, noting the residual cost of replaced mains in our capital base exists because of its replacement before it's fully depreciated; and that this will reduce our return on investment in the next period by around $9 million per year.
Stage 4 Engagement : Refining our Plans	
• We continued to engage with CCP24 on managing stranded asset risk. • We advised SARG and RRG of our approach to depreciating the capital base and they supported our proposal.	• We have applied the same approach to depreciation as approved by the AER previously for mains that have been replaced or removed from the capital base. • We are not proposing any changes to our current approach to depreciation at this stage in response to the energy transition, instead preferring to wait for more information to become available on the role of gas in a low carbon future.
Final Plan Outcome	
With the support of stakeholders, we are not at this stage proposing substantive changes to the economic lives of our assets in response to the uncertainty over the role of gas networks in a low carbon future – while there are risks that need to be addressed over time our assessment suggests it is better to wait until the subsequent AA period before acting. We have applied the same approach as approved by the AER for our Victorian and Albury network whereby mains that have been replaced are depreciated by the end of the next AA Period. Stakeholders supported AGN's proposed approach to depreciation, in particular to review asset lives as part of the subsequent AA period.	

9.3 Capital Base as at 1 July 2021

We have adjusted (or rolled-forward) our capital base with actual capex and inflation and forecast depreciation over the current AA period. We have used forecast information for 2019/20 and 2020/21 as actual information is not yet available.

Table 9.2 shows the adjustments we have made to our capital base over the current AA period. The "funding adjustment" reflects the difference between the forecast and actual capex in the last year of the previous AA period (i.e. 2015/16). Consistent with AER practice, the adjustment reflects the return recovered by AGN that otherwise would have occurred if actual information for 2015/16 were available.

The closing value of the capital base forms the opening capital base for the next AA period.

9.4 Capital Base as at 30 June 2026

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

9.4.1 Capital Expenditure

Our forecast capex was discussed in Chapter 8 of this Final Plan and is reproduced in Table 9.3, with the capex 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 not the same as our capex forecast in Chapter 8). The AER makes this adjustment to account for the fact that we do not earn a return on the capex within the year it was spent.

Table 9.2: Roll Forward of the Capital Base 2016/17 to 2020/21 ($nominal, million)

	2016/17	2017/18	2018/19	2019/20	2020/21
Opening Capital Base	1,392.3	1,456.9	1,534.8	1,614.1	1,690.3
Less Depreciation	-23.4	-21.2	-28.9	-33.5	-31.0
Plus Conforming Capex	93.4	96.4	103.3	102.8	143.8
Plus Actual Inflation	1.2	2.7	4.9	6.8	12.4
Less 2015/16 Capex Adjustments	-4.2	0.0	0.0	0.0	0.0
Less Funding Adjustment	-2.5	0.0	0.0	0.0	0.0
Closing Value	**1,456.9**	**1,534.8**	**1,614.1**	**1,690.3**	**1,815.4**

Note: Totals may not add due to rounding.

9.4.2 Forecast Depreciation

We have continued to apply the asset lives that were approved by the AER for the current AA period (as shown in Table 9.4).

In determining forecast depreciation for the next AA period, we have applied the 'year-by-year' tracking approach. This approach is consistent with that used by the AER for other networks, including our AGN Victoria and Albury network, and Multinet Gas Network.

We have not made any changes to economic lives in the face of the issues noted in Section 9.2. However, we have begun considering how to assess the impact of the energy transition, as outlined in Section 9.5.

We are also seeking to ensure that the value of the assets removed from our network as part of the mains replacement program are fully depreciated by the end of the next AA period (see Section 9.3).

This adjustment is made to ensure that our prices are based on the efficient costs of providing services to our customers. This in turn will ensure intergenerational equity as future customers will not pay for assets that are no longer in use.

We have engaged Incenta to review the appropriateness of this adjustment to depreciation (Attachment 9.1). Incenta's report states that:

"We agree with AGN that the most practicable method of addressing the replaced assets is to deduct the value of the assets projected to be replaced by the end of the access arrangement period…"

Incenta have estimated the residual value of the low-pressure mains and associated services, as at 1 July 2021, to be $252 million. We have depreciated these residual values equally over each year of the next AA period (see Attachment 9.1).

We consider a five-year depreciation period achieves the objective of ensuring that the low-pressure mains and services are fully depreciated after they are replaced in our network. By smoothing this depreciation evenly over five years, price volatility is minimised.

Table 9.5 shows our forecast straight-line depreciation, which reflects the year-by-year tracking approach as well as the amendments to depreciation on account of the mains replacement program. We propose that forecast depreciation be used for establishing the opening capital base for the subsequent AA period.

9.4.3 Inflation

Forecast inflation is a critical element to determine our total revenue and prices. As explained earlier, forecast inflation is used to adjust the capital base over the next AA period. This forecast is later updated for actual inflation when adjusting the capital base for the previous AA period.

Forecast inflation is also used in determining the total revenue that we can recover (and hence the prices we can charge). This is reflected in the methodology that the AER uses to determine our total revenue. This method relies on inflation to determine the following two 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 9.6) the forecast inflation adjustment applied to the capital base.

The AER removes inflation in determining regulatory depreciation to remove any additional compensation for inflation in determining the return on capital, which arises from multiplying a nominal rate of return by a nominal capital base (referred to as a double count of inflation).

In April 2020, the AER announced a review of its current approach to forecasting inflation. We consider a review is appropriate as the current approach has consistently forecast inflation higher than actual inflation. We will engage with the AER through their inflation review, with the expectation that the outcome will be available by the time of the AER's Final Decision for our South Australian network, expected in April of 2021.

In this Final Plan, we have used an estimate of inflation formed using the AER's current approach, but we expect this value may change reflecting the outcome of the aforementioned review by the time of the AER's Final Decision.

Consistent with our objective of developing a plan that is capable of being accepted by our customers and stakeholders, we will apply the AER's inflation decision as soon as it is available (likely in our response to the AER's Draft Decision).

Table 9.3: Forecast Capex 2021/22 to 2025/26 ($nominal, million)

	2021/22	2022/23	2023/24	2024/25	2025/26
Mains	79.2	77.6	73.2	71.8	62.5
Inlets	12.1	14.3	15.4	16.6	16.6
Meters	5.5	6.1	7.8	7.1	7.9
Telemetry	0.6	0.4	0.4	0.4	0.3
IT system	2.4	5.6	11.2	11.3	6.1
Other distribution system equipment	9.1	13.6	13.5	12.8	12.6
Other	1.2	1.2	0.8	0.9	1.0
Closing Value	**110.1**	**118.7**	**122.3**	**120.8**	**107.0**

Table 9.4: Summary of Lives Used to Calculate Depreciation

Asset Category	Standard Useful Life (years)
Mains	60
Inlets	60
Meters	15
Telemetry	20
IT system	5
Other distribution system equipment	40
Other	10

Table 9.5: Forecast Straight-line Depreciation, 2021/22 to 2025/26 ($nominal, million)

	2021/22	2022/23	2023/24	2024/25	2025/26
Straight-line Depreciation	99.1	105.1	111.2	110.5	117.2

9.4.4 Forecast Regulatory Depreciation

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 (as described in Section 9.4.3). Table 9.6 shows forecast regulatory depreciation that is used to determine assumed total revenue for the next AA period, which as explained has been determined using the AER's preferred approaches to calculating both depreciation and inflation.

9.4.5 Forecast Capital Base

The forecast capital base over the next AA period, taking into account forecast depreciation, capex and inflation, is set out in Table 9.7. This shows a closing capital base of $2,076 million as at 30 June 2026 in nominal dollar terms.

Table 9.7: Forecast Regulatory Depreciation, 2021/22 to 2025/26 ($nominal, million)

	2021/22	2022/23	2023/24	2024/25	2025/26
Straight-line Depreciation	99.1	105.1	111.2	110.5	117.2
Less Inflation	42.0	43.4	44.9	46.4	48.1
Regulatory Depreciation	**57.1**	**61.7**	**66.3**	**64.0**	**69.1**

Table 9.6: Forecast Capital Base, 2021/22 to 2025/26 ($nominal, million)

	2021/22	2022/23	2023/24	2024/25	2025/26
Opening Capital Base	1,769.3	1,826.2	1,890.2	1,955.6	2,024.5
Less Straight Line Depreciation	-99.1	-105.1	-111.2	-110.5	-117.2
Plus Conforming Capex	114.0	125.7	131.7	132.9	120.5
Plus Actual Inflation	42.0	43.4	44.9	46.4	48.1
Closing Value	**1,826.2**	**1,890.2**	**1,955.6**	**2,024.5**	**2,075.9**

Note: Totals may not add due to rounding.

9.5 Economic lives

As outlined earlier in the *Future of Gas* section, the future use of gas networks will be determined by a combination of technology developments, government policy and the cumulative decisions of millions of customers.

We have chosen not to propose any changes to the existing approach to depreciation on account of this issue for the next AA period.

However, we believe a framework for addressing this issue needs to be developed so that economic lives can be transparently and robustly considered for future AA periods.

Such a framework should consider the increasing competition faced by the gas distribution network from distributed renewable energy and the changes we could start to make now, on a relatively small scale. Such changes would be aimed at developing options to deal with the variety of potential futures currently open to the energy sector and gas distribution networks.

We believe a particular focus should be given to depreciation because this is the building block we think is best suited to address future risks and opportunities.

A risk assessment approach (or real options framework) is our preferred method for considering changes to depreciation and is compatible with the approach to depreciation in the NGR (rule 89) as it enables changes in economic lives to be reflected over time.

We have therefore been working to develop such a framework using:

- a model of potential future pathways for the energy sector; and
- a model for translating those pathways into consequences for depreciation now.[3]

While we have begun to consider possible pathways the energy sector might take and the changes we could start to make now, such changes may have implications across networks and for customers across Australia. Developing the right approach should be subject to wider consultations with the AER, customers, stakeholders and networks as was recommended by CCP24.

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 adoption of the year-by-year tracking approach and the completion of our mains replacement program during the next AA period. This adjustment is consistent with previous decisions made by the AER for our Victorian and Albury networks, as well as for other regulated businesses across gas and electricity. We have also applied the AER's approach to forecast inflation, and note the review the AER is currently undertaking.

The impact of these adjustments over the next AA period results in a closing capital base of $2,076m on 30 June 2026.

[3] See Crew, M and Kleindorfer, P, 1992, "Economic Depreciation and the Regulated Firm under Competition and Technological Change", *Journal of Regulatory Economics*, 4(1), 1992, 51-61. See also Biggar, D, 2011, *The Fifty Most Important Papers in the Economics of Regulation*, ACCC/AER Working Paper No. 3, May 2011, p21

10 Financing costs

IN THIS CHAPTER:

We have followed the AER's Rate of Return Instrument to estimate the rate of return.

Based on market estimates, the average rate of return is 4.40% (compared to 6.14% at the start of the current AA period).

We are expecting lower financing costs in the next AA period, with the return on our investment falling by $109 million.

Our single largest cost relates to financing our $1.8 billion investment in the South Australian natural gas distribution network.

In this Final Plan, the allowed rate of return and the cost of tax have been calculated according to the AER's 2018 Rate of Return Instrument and the recent Tax Review.

Financing the $1.8 billion investment in the South Australian gas distribution network is our single largest cost. Achieving a reasonable rate of return 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 our business will incur over the next AA period.

The transition underway in the energy sector is not without risks for gas networks – risks over and above those being faced by electricity networks.

Despite this, gas and electricity networks receive the same rate of return. In this light, our prices represent very good value for our customers and the South Australian economy.

10.1 Regulatory Framework

The NGR provides a framework for calculating the return on the projected capital base (rate of return).[1] The AER's 2018 Rate of Return Instrument details the approach we are required to follow for calculating the rate of return under the NGR.[2]

The Instrument also outlines the AER's methodology for calculating the value of imputation credits (gamma) to equity holders, which is used to calculate the cost of tax building block. Further guidance in respect of the cost of tax is also provided in the AER's December 2018 Tax Review.[3]

We have followed the AER's approach in respect of all aspects of our financing costs and tax allowances.

10.2 Customer and Stakeholder Engagement

In our engagement program and in the Draft Plan we advised customers and stakeholders that we have applied the AER's Rate of Return Instrument and accepted the outcome of the AER's Tax Review. Stakeholders supported our approach and noted this is consistent with submitting a plan that is capable of being accepted.

No change has been made to this approach in the Final Plan. See Table 10.1.

[1] NGR 87

[2] See https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rate-of-return-instrument-2018

[3] See https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/regulatory-tax-approach-review-2018

Table 10.1: Summary of customer and stakeholder engagement outcomes – Financing costs

Financing Costs	
Customer and Stakeholder Feedback	**Our Response**
Stage 1 and 2 Engagement : Developing our Plans	
Stakeholders acknowledged our intention to adopt the AER's Rate of Return Instrument, and a tax allowance of zero, consistent with the approach taken in the recent AER Tax Review. Stakeholders noted this is consistent with submitting a plan that is capable of being accepted.	• We have applied the AER's Rate of Return Instrument. • We have accepted the outcome of the AER's Tax Review. The forecast tax allowance for the next AA period is zero.
Stage 3 Engagement : Draft Plan Consultation ⇨ Do you have any comments on our approach to setting the financing and tax costs in this Draft Plan?	
Customers acknowledged AGN's intention to adopt the AER's Rate of Return Instrument in formulating its plans. Stakeholders supported the AER's review of tax allowances, resulting in an allowance of zero for AGN. Stakeholders questioned whether AGN's proposed debt return should be reduced to reflect currently low interest rates.	• We advised customers that applying the AER Rate of Return Instrument is consistent with the approach taken for other AGIG assets, and that this is consistent with submitting a plan which is capable of being accepted by our customers and stakeholders. • Stakeholders were informed that the return on debt is based upon a 10-year trailing average in line with the AER's Rate of Return Instrument.
Stage 4 Engagement : Refining our Plans	
No further feedback was received on our financing costs.	• Our proposal applies the AER's Rate of Return Instrument and the outcome of the AER's Tax Review.
Final Plan Outcome	
We have applied the AER's Rate of Return Instrument in this Final Plan, and this approach is supported by customers and stakeholders. The rate of return applied in this Final Plan is 4.40%. We have also updated our approach to calculating the tax allowance following the AER's Tax Review.	

10.3 Financing Costs

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

10.3.1 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 an estimate of the return on equity required by shareholders.

The AER estimates the return on equity using a "foundation model",[4] which requires the following three parameters to be estimated:

- *Risk free rate* – which measures the return an investor would expect from an asset with no risk. It is estimated based on the interest rate on Australian Commonwealth Government bonds with a 10-year term, measured over a 20-day 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

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

- *Equity beta* – which measures the sensitivity of a business' returns relative to movements in the overall market returns (systematic or market risk).

We have applied the AER's foundation model from the 2018 Rate of Return Instrument, which results in a return on equity of 4.72% over the next AA period (see Table 10.2).

These values are indicative and were measured using current market information. Updated information will be used in the AER's Final Decision. We have proposed no change to the risk free rate averaging periods that apply in the current period.

10.3.2 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).

The return on debt is measured as a 10-year trailing average, with each "tranche" (equal to one-tenth of the debt portion of our RAB) being updated annually.

The return on debt for each tranche is formed as a weighted average of A-rated debt indices (one-third weight) and BBB-rated debt indices (two-thirds weight). The third-party indices that are used to provide the required debt information are provided by the Reserve Bank of Australia, Bloomberg and Thomson Reuters.

Unlike the return on equity, the return on debt is updated annually and, once calculated, the cost of debt for a given tranche remains in place for ten years. This assumes that we refinance our debt equally over a 10-year period.

We have reflected the trailing average cost of debt in our Final Plan. In effect, this means that the weighting of the cost of debt estimate for 2021/22 is applied - 10% in each year of the AA period.

As our estimate of the cost of debt is lower than the historically higher priced tranches of debt in the portfolio, the cost of debt and hence the rate of return is forecast to reduce in each year of the AA period. The cost of debt and rate of return over the current and next AA periods is shown in Figure 10.1.

There is a change to duration of the debt averaging period that applies relative to the current AA period. Due to the sensitive nature of the information, this averaging period is not disclosed in our Final Plan (but is provided to the AER for its approval in Attachment 10.1 as consistent with the Rate of Return Instrument).

Applying the AER's Rate of Return Instrument yields an average return on debt of 4.19%, which we have applied in this Final Plan.

Table 10.2: Indicative return on equity

Parameters	
Risk Free Rate	1.06%
(Average of observed yields on 10-year Australian government bonds over agreed averaging period)	(Using a placeholder 20-day averaging period using forward rates for 30 June 2021)
Equity Beta	0.6
Market Risk Premium (MRP)	6.10%
Return on Equity	**4.72%**

Figure 10.1: AGN SA Debt Allowance and Rate of Return

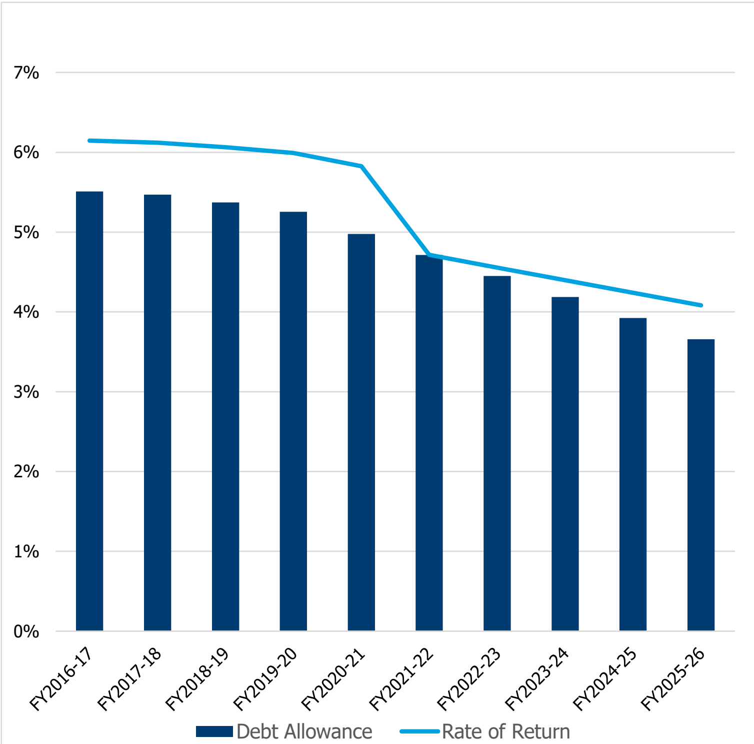


Table 10.3: Roll forward of the tax asset base ($million, nominal)

	2021/22	2022/23	2023/24	2024/25	2025/26
Opening tax asset base	913.4	891.6	874.4	853.1	824.8
Plus gross capex	112.7	124.4	131.2	132.7	120.3
Less tax depreciation	-134.5	-141.5	-152.5	-161.0	-152.4
Closing tax asset base	**891.6**	**874.4**	**853.1**	**824.8**	**792.7**

Note: totals may not add due to rounding

10.3.3 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 (4.72%) and average return on debt (4.19%) results in an average rate of return of 4.40% over the next AA period. This rate of return declines each year in the next AA period due to our application of the trailing average cost of debt approach.

10.4 Cost of Tax

We have reflected the outcomes of the AER's December 2018 Tax Review in this Final Plan. Our cost of tax building block is based on an assessment of our taxable income, the applicable corporate tax rate and the value of imputation credits (gamma) to equity holders.

Implementing the approach in the AER's tax review results in our tax allowance being zero for each year of the next AA period.

10.4.1 Calculating the Cost of Tax

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

- *Total revenue* is the sum of all of our costs (or building blocks) (see Chapter 13);
- *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; and
- *Interest expense* is determined by multiplying the cost of debt by 60% of our capital base in each year, reflecting the debt funded proportion of the total capital base.

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.

10.4.2 Value of Imputation Credits

The value of imputation credits (or gamma) 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).

The value of imputation credits (or gamma) is 0.585 as determined in the AER's 2018 Rate of Return Instrument.

The effect of gamma is to reduce any tax allowance by 58.5%. However, gamma has no effect on this Final Plan because the AER's tax depreciation approach results in a Net Tax Allowance of zero.

10.4.3 Tax Depreciation

Our approach to determining tax depreciation for the next AA period has changed from that applied in the current AA period, reflecting the changes prescribed in the AER's Tax Review.

The AER gave effect to three key changes through the review:

- the use of maximum 20-year tax asset lives for new gas assets;
- the use of a diminishing value method (rather than a straight-line method) to calculate tax depreciation over those 20 years; and
- introducing the 'actuals informed approach' to the expensing of some forms of capex. The AER Tax Review prescribed that networks mirror in the regulatory model the approach they adopt for

determining their actual tax cost.

These changes, to the extent that they were not previously used by AGN, apply to new assets only, as tax law does not allow for retrospective changes to the approach to calculating tax depreciation.

10.4.4 Tax Asset Base

The opening TAB of $913 million ($nominal) as at 1 July 2021 has been adjusted for the same forecast information used to adjust our capital base over the next AA period (see Table 10.3).

10.5 Summary

Our financing and tax costs collectively account for around 39% of our total costs. For the purposes of this Final Plan, we have applied the AER's Rate of Return Instrument and the AER's Tax Review in determining our financing and tax costs.

This results in a rate of return of 4.40% (see Table 10.4) and a Net Tax Allowance of zero.

Table 10.4: Indicative AER Rate of Return and Gamma

Parameters	AGN Final Plan
Return on Equity	4.72%
Average Return on Debt	4.19%
Average Rate of Return	4.40%
Gamma	0.585


Australian
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6
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CONNECTION

11 Incentives

IN THIS CHAPTER:

We propose to strengthen our incentives through the introduction of a capital expenditure incentive scheme.

We are also proposing to introduce a network innovation scheme to fund innovation projects that deliver benefits to our customers.

The existing operating expenditure efficiency scheme (EBSS) has achieved over $22 million in ongoing efficiency improvements over three AA periods.

The benefits of the EBSS have been passed on to our customers through lower prices.

Our incentive to seek out efficiencies and other performance improvements will be strengthened in the next AA period through the addition of two new incentive schemes.

We support the use of effective, outcome-based incentive schemes that promote the long-term interests of our customers.

Incentive schemes are often used by regulators to:

- strengthen a service provider's incentive to continuously seek out efficiency and performance improvements and share the benefits with customers;
- balance incentives between opex and capex so that the most efficient expenditure mix is chosen;
- pursue efficiencies while improving or maintaining service quality; and
- encourage investment in innovation in areas that can provide longer-term benefits to our customers.

To date, the only incentive scheme that has applied to our South Australian network is the opex efficiency benefit sharing scheme (EBSS). We are proposing to continue this scheme in the next AA period.

We are also proposing to supplement the opex EBSS with a capex efficiency sharing scheme (CESS). The CESS will strengthen our incentive to seek out capex related efficiencies, while also maintaining service standards and the health of our network. The CESS will be contingent on network performance to ensure efficiency gains are not made at the expense of network safety or reliability.

To further strengthen our incentives over the next AA period, we are also proposing the introduction of a network innovation scheme. We will continue to engage with our customers and stakeholders, the AER and the broader industry over the coming months to define the scope and form of the network innovation scheme.

While we consider there is merit in the introduction of a customer service incentive scheme we have chosen not to pursue this because our customer satisfaction scores are improving without such a scheme.

The following sections provide further detail on regulatory requirements for the incentive schemes, the feedback our customers and stakeholders have provided and our proposed incentive schemes.

11.1 Regulatory framework

A key objective of the regulatory framework is to promote efficient investment in, operation and use of gas distribution networks for the long-term interests of customers.

In keeping with this objective, the NGR provide for gas networks to have incentive schemes apply to encourage the efficient provision of services.[1]

The NGR also require any incentive mechanism to be consistent with the revenue and pricing principles, the most relevant of which is the principle that a service provider should be provided with effective incentives to promote:

- efficient investment in (or in connection with) the network;
- the efficient provision of services; and
- the efficient use of the network.[2]

11.2 Customer and stakeholder engagement

To ensure we are delivering value for customers, stakeholders were keen to understand that our costs are efficient – and that there are incentives in place to align with this.

We discussed incentives and presented our proposed approach to our reference groups in December 2019 and in more detail throughout the first half of 2020 during Draft Plan consultation (see Table 11.1).

In our Draft Plan we included a proposal to consider an innovation scheme. This was based on feedback from customer workshops that our customers value investment in innovation projects. Similarly stakeholders were interested in discussing opportunities for innovation and the benefits this can deliver.

During customer workshops almost 8 in 10 customers were either supportive or strongly supportive of investment in innovation (through an Innovation Allowance) where there is potential to improve customer service efficiency or sustainability.

Customers cited the importance of innovation in contributing to finding better and more effective ways of working; as well as pursuing innovative projects which can deliver environmental benefits.

Based on this customer support, and our own view on the importance of innovation, we are proposing to introduce a network innovation allowance of between $2.5 - $5 million over the next AA period.

We intend to continue to engage with our customers and stakeholders, the AER and the wider industry over the coming months to define the scope and form of the innovation scheme in time for the AER's Draft Decision in November 2020.

We have received broad stakeholder support for our proposed approach for a CESS and an Innovation Allowance.

11.3 Opex EBSS

An opex EBSS applies in the current AA period to our South Australia distribution network. We are proposing that this incentive scheme continue in the next AA period.

Further detail on how the EBSS works, where it applies and the benefits it has delivered our customers is provided below.

11.3.1 How the opex EBSS works

The opex EBSS is a key element of our opex forecasting approach (see section 7.3)[3] and is designed to provide a continuous incentive to pursue opex efficiency improvements in any particular year of an AA period and to share any efficiency gains (or losses) with our customers.

The EBSS operates in a symmetric manner, which means that we are rewarded if there is an incremental efficiency gain, and penalised if there is an incremental efficiency loss.

To ensure that we have an incentive to pursue efficiency gains evenly throughout the AA period, we are able to retain the benefit of any efficiency gain (or incur the cost of any efficiency loss) for five years. After the relevant AA period, the benefit (cost) is passed through to our customers in the following AA period.

In effect, the EBSS provides for 70% of the efficiency gains (or losses) to be passed through to our customers in the form of lower (higher) prices.

The revenue adjustment in the next AA period as a result of the EBSS (and efficiency gains achieved) in the current AA period is outlined in Chapter 13.

[1] NGR 98
[2] NGL 24(3)
[3] Our opex forecasting approach relies on actual incurred opex in the penultimate year of an AA period being efficient.

Table 11.1: Summary of customer and stakeholder engagement outcomes - Incentives

Incentives	
Customer and Stakeholder Feedback	**Our Response**
Stage 1 and 2 Engagement : Developing our Plans	
Stakeholders noted that AGN is considering a capital expenditure sharing scheme (CESS) to compliment the current opex incentive scheme and that consideration is also being given to customer service and innovation incentive schemes. SARG discussed the incentive mechanisms, noting that while they can deliver better outcomes for customers, they need to be appropriately specified to operate as intended. Customers were keen to understand opportunities for AGN to be innovative, with almost 8 in 10 customers either supportive or strongly supportive of AGN investing in innovation. Customers told us the importance of innovation is that it contributes to finding better, more effective and efficient ways of providing services to customers.	• We consider incentive mechanisms to be an important part of a regulatory framework that helps to deliver efficiencies to customers in a timely manner. • We are therefore proposing the continuation of the AER's opex incentive mechanism that currently applies in South Australia, as well as a capex incentive mechanism consistent with that approved by the AER for our Victorian gas network and more recently for Jemena Gas Networks. • We included an innovation scheme proposal for testing customer support as part of Draft Plan consultation.
Stage 3 Engagement : Draft Plan Consultation ⇨ Do you support our proposal to maintain the opex efficiency benefit sharing scheme (EBSS)? ⇨ Do you support our proposal to introduce a contingent capital expenditure efficiency scheme (CESS)? ⇨ Do you think a network innovation scheme should be implemented? If so, what level of funding do you think should be allowed under this scheme; for example $1 per year ($2.5 million), $2 per year ($5 million) and so on? What type of projects should be in the scope? ⇨ Do you think a customer service incentive scheme (CSIS) should be implemented?	
87% of customers support a small price increase to better support investment in innovation projects. 54% indicated they would be prepared to pay a price of $2 per annum for an innovation fund. Stakeholders broadly supported our proposals for incentives noting that AGN would continue to engage industry on the development of the proposal. CCP24 noted the need for ongoing engagement with the industry.	• We advised stakeholders that over the coming months we will undertake wider industry engagement, including with other gas distributors, to inform the appropriate design and scope of the Innovation Scheme, including to determine the amount, type of scheme and AER/ Panel to review innovation projects
Stage 4 Engagement : Refining our Plans	
SARG and RRG support our proposed approach to incentives, including the continuation of the EBSS, the introduction of a CESS and proposed introduction of an Innovation Allowance.	• Our proposals relating to incentives are included in Chapter 11 of this Final Plan.
Final Plan Outcome	
This Final Plan includes a continuation of the opex incentive mechanism (EBSS) that currently applies for our South Australian network. The Final Plan proposes a new capex incentive mechanism (CESS) consistent with that approved by the AER for our Victorian gas network and more recently for Jemena Gas Networks (Chapter 11 Sections 11.3 and 11.4). Stakeholders and customers support investment in innovation. As part of this Final Plan we have therefore proposed to introduce an Innovation Scheme, the design of which will be determined through a specific industry-wide engagement program conducted post Final Plan submission (see Section 11.5).	

11.3.2 Where it is used

For our South Australian network an opex EBSS has been in place for three AA periods. Over these periods, we have achieved over $22 million in ongoing efficiency improvements, the benefits of which have been (or will be in the next AA period) passed through to our customers. We calculate the scheme has delivered $282 million in benefits to our customers since its introduction.

An opex EBSS is also in place on all other gas and electricity distribution and transmission networks regulated by the AER. In July 2019 Energy Networks Australia published *Rewarding Performance: How customers benefit from incentive-based regulation*, which calculated customer benefits in the order of $3 billion delivered through the operation of EBSS schemes applied to electricity and gas service providers in Australia between 2006 and 2018.

11.4 Capex CESS

While we have had an opex EBSS in place for a long period, we have not had an equivalent capex incentive scheme in place. We are therefore proposing to strengthen and balance our incentives by introducing a CESS.

The form of our proposed CESS mirrors the 'Contingent CESS' that was recently approved by the AER for our Victorian and Albury networks. The AER has more recently approved a CESS for Jemena Gas Networks in New South Wales for the 2020-2025 AA period.

The 'Contingent CESS' was introduced in Victoria following an extensive industry engagement program that included stakeholder representatives and gas distributors at a national level. Further detail on how this CESS works and where it currently applies is provided below.

11.4.1 How the CESS works

In a similar manner to the EBSS, the CESS would provide a continuous incentive to pursue capex related efficiency improvements over the AA period and to share any efficiency gains (or losses) with our customers.

The CESS would also:

- reduce inefficient growth in our capital base by increasing the incentive to incur efficient capex; and
- address the imbalance in incentives that currently applies to decisions regarding whether opex or capex should be undertaken.

Under the Contingent CESS, 70% of any incremental capex efficiency gains (or losses) we achieve would be passed on to our customers.[4][5] These gains would be subject to two conditions.

- Firstly, any efficiency gain or loss would be contingent on maintaining service standards and the health of the network, which would be measured using an Asset Performance Index (API).
- Secondly, if we defer capex from one AA period to the next, the efficiency gain would be reduced.

These elements of the CESS are designed to ensure that cost savings are achieved through efficiency improvements, not reduced service levels, or an inefficient deferral of capex.

11.4.2 Where it is used

As noted above, the AER has recently allowed a 'Contingent CESS' to be applied to all gas distribution networks in Victoria and Jemena's NSW gas distribution network. In each case, some of the API measures differ to reflect specific network characteristics. A form of the CESS also applies to the electricity distribution and transmission networks regulated by the AER.

11.4.3 The Asset Performance Index

The API is used in the contingent CESS to determine how much of the efficiency gain we are able to retain. This metric reflects both:

- service performance - as measured by the unplanned system average interruption frequency index (SAIFI) and unplanned system average interruption duration index (SAIDI); and
- the health of the network - as measured by number of reported leaks in gas mains, services and meters.

We propose the same performance measures and the same approach to setting the targets as the AER applied for our Victorian networks. Specifically:

- Performance measures: unplanned outages and duration and mains, services and meter leaks; and
- Targets: average of last five years performance, with unplanned outages and duration weighted at 25% each and mains, services and

[4] The CESS applies to capex, net of contributions and disposals, and adjusts for material deferrals, the effect of ex post capex reviews and cost pass throughs.
[5] These benefits and costs must be adjusted for any financing benefits or costs.

meter leaks making up the other 50% of the index based on their relatively share of our asset base.

The targets and weightings for each of these measures are shown in Table 11.2.

Table 11.2: Asset performance index measures, targets and weightings

Measure	Target	Weight
Unplanned SAIFI	0.69	25.0%
Unplanned SAIDI	314.97	25.0%
Mains leaks	0.11	42.3%
Service leaks	3.76	4.9%
Meter leaks	12.35	2.7%

If we meet or exceed these targets, we can retain 30% of the efficiency benefit. However, if we do not meet these targets, the benefit can be reduced on a sliding scale, potentially to zero if we fall below 80% of the performance target. This provides customers with assurance that efficiency gains will not come at the cost of network performance or network health.

The sliding scale does not operate in the opposite direction (i.e. we do not receive a reduced financial penalty for any efficiency losses, even where there has been improved network performance). This asymmetric approach reflects the fact that customers are satisfied with the current safety and reliability performance they receive and are not willing to pay more for further improvements.

More information on the calculation of the API targets can be found in Attachment 11.1.

11.5 Network innovation allowance

Innovation on our network has the potential to promote the National Gas Objective by:

- promoting the efficient provision of services over the longer term; and/or
- enabling other customer objectives to be met (e.g. to meet emissions targets and/or to support renewable energy technologies).

However, the current regulatory framework makes it difficult to invest in innovation. This is because innovation most often results in increased expenditure in the short term and the payback period for innovation investment is often more than five years. This is in contrast to the EBSS and CESS, which provide incentives to reduce costs, with benefits and losses recovered over a five-year period. In the absence of an innovation scheme, there are reduced incentives to investment in innovation, particularly where the payback period on the investment is five or more years.

During our customer and stakeholder engagement program we found that customers support investment in innovation on the network (through an Innovation Allowance). Almost 8 in 10 customers were either supportive or strongly supportive of investing in innovation, with a small proportion (8%) seeing this as not at all or slightly important.

Based on this customer support, and our own view on the importance of innovation in addressing the National Gas Objective, we are proposing to introduce a network innovation allowance (or scheme) in the next AA period.

A network innovation allowance would provide a clear framework (including rules and requirements) for funding of innovative projects.

Noting that there is a need for a whole of industry approach to innovation, we intend to continue to engage with our customers and stakeholders, the AER and the wider industry over the coming months to define the scope and form of this scheme in time for the AER's Draft Decision in November 2020.

11.5.1 How an innovation scheme could work

Network innovation schemes have been used by regulators to counter the lower incentive service providers have to invest in innovation, relative to businesses operating in competitive markets.

The lower incentive stems from the resetting of costs and prices at five-yearly intervals. This relatively short period means that a service provider may be unable to retain the benefits of innovation for a sufficiently long period to recover the investment. This is particularly the case where:

- the payback period for an investment in innovation is longer than the AA period; and
- an allowance for the investment is not included in the opex and/or capex allowance and an EBSS and/or CESS applies.

To address this issue, some regulators have provided service providers funding to undertake eligible innovation based projects.

An example of such a scheme is the Demand Management Innovation Allowance Mechanism (DMIAM) that applies to electricity networks regulated by the AER.

This scheme provides funding for research, development and implementation of eligible projects that have the potential to reduce the long-term cost of service provision.

In the UK, innovation schemes also apply to gas networks for low carbon and general innovation investments.[6]

We will look to the DMIAM as well as schemes in place in the UK to guide the scope and form of such a scheme for the next AA period. Rather than focusing on demand (as is the case for the DMIAM), it would focus on eligible projects that are designed to promote the efficient provision of services over the longer term (in line with the approach adopted in the UK). This would include supporting:

- the decarbonisation of gas networks; and
- the potential for smarter gas networks.

To be an eligible project, the proposed project would have to:

- involve the research, development, or demonstration of a new or original concept, technology or technique, not previously implemented that has the potential to reduce the carbon footprint of gas distributed by our network; and/or
- have the potential to deliver net financial benefits and/or improvements in our services to gas customers.

Based on proposals and costs we tested with our customers, we consider a scheme that would allow between $2.5 - $5 million over the period in the next AA period for innovation is appropriate. To put this into perspective, $2.5 million over the period translates to around $1 per year on an average customer's bill.

We will also consider whether or not we should match any funding provided through the scheme (so that we bear the same risk as our customers if the project fails).

Finally, we will also consider who reviews projects to determine their eligibility for funding under the scheme, as well as how to ensure that the findings of investments are shared across the wider industry, to help the share knowledge in customers' interests.

11.5.2 Where it is used

As mentioned above, a form of the network innovation scheme, the DMIAM, currently applies to electricity distribution networks regulated by the AER. A network innovation scheme also applies to electricity, gas and water businesses in the UK.

11.6 Customer service incentive scheme

We considered the introduction of a Customer Service Incentive Scheme (CSIS) for the next AA period as part of our engagement program and Draft Plan. However, we note that our customer satisfaction scores – measured for nearly five years – continue to improve, reflecting our ongoing focus on our customers. We therefore do not consider that a CSIS is required for the next AA period.

We have committed to achieve customer satisfaction scores of at least 8.2 out of 10 in the next AA period (see Chapter 4).

11.7 Summary

In the next AA period we are proposing to strengthen our incentives to pursue efficiencies and to share the benefits with our customers. We are proposing to supplement the existing opex EBSS with a CESS.

We are also proposing to introduce a network innovation allowance. The scope and form of the allowance will be the subject of ongoing consultation with our customers and stakeholders, the AER, and the wider industry over the coming months.

To follow this engagement process or be involved in any of the engagement activities on the network innovation scheme please visit our dedicated engagement website gasmatters.agig.com.au.

[6] Office of Gas and Electricity Markets, https://www.ofgem.gov.uk/network-regulation-riio-model/current-network-price-controls-riio-1/network-innovation

12 Demand Forecasts

IN THIS CHAPTER:

Our demand forecasts have been independently determined applying methodologies consistent with those approved previously by the AER.

Overall demand for gas in the residential, commercial and industrial sectors is expected to fall consistent with past trends.

The impacts of COVID-19 have been reflected in our forecasts, with a short-term decline in the number of detached and multi-unit dwellings to be constructed expected.

We expect to continue to experience strong customer growth in the next AA period following a short-decline due to the impact of the COVID-19 pandemic. Total connections are expected to exceed 490,000 at the end of the period.

Customers will continue to connect to our network but with lower average usage consistent with previous trends.

Our forecasts of natural gas demand and customer numbers are key inputs to our growth capex and opex forecasts. They are also used to determine our prices (reference tariffs), which are calculated by dividing our forecast revenue requirement by forecast demand.

Customers are projected to continue to connect to the network, however the overall trend in the demand for natural gas continues to decline driven by a range of factors. We observe improved efficiency of gas appliances, alternative (low emissions) energy sources, high retail gas prices and changes in climate all of which reduce demand for natural gas.

Separate demand and customer connection forecasts have been developed by independent expert Core Energy & Resources ('Core Energy'), for each customer class, namely:

- Residential;
- Commercial (business customers who use less than 10 terajoules of gas each year); and
- Industrial (our largest business customers).

These customer groups are consistent with our proposed Haulage Reference Services to be provided over the next AA period.

In the next AA period, Core Energy forecasts the total demand for natural gas for our:

- Residential segment to fall by 1.5% per year, comprising connection growth of 1.0% but a decline in average consumption of 2.6%. The decline in average consumption reflects a response to a range of external factors, such as higher wholesale gas prices, increasing penetration of solar energy, improved appliance and dwelling efficiency and lower new dwellings growth;
- Commercial segment to grow by 0.3% per year, comprising connection growth of 0.6% but a decline in average consumption of -0.3%. Commercial connections are forecast to rise by 0.6% per year driven by slightly higher projected levels of economic activity in South Australia; and
- Industrial connections to fall by 2.9% per year in response to higher wholesale gas prices and in turn driving capacity lower by 3.1% per year.

Core Energy's residential connection forecast is derived from the latest view of housing starts from the Housing Industry Association (HIA).

Overall, Core Energy projects that the total demand for gas will fall by 1.9% per year in the next AA period.

The following sections provide more detail on the relevant regulatory framework, the forecasting method and the demand forecasts themselves.

12.1 Regulatory framework

Our AA proposal must include the forecast demand for reference services. In keeping with the NGR, these forecasts must:[1]

- be arrived at on a reasonable basis; and
- represent the best forecast possible in the circumstances.

The AER also identified a number of principles of best practice for demand forecasting in its 2013 Better Regulation program. The AER concluded that forecasts should:

- be accurate and unbiased;
- be transparent and repeatable;
- incorporate key drivers;
- incorporate a suitable method of weather normalisation; and
- be subject to statistical model validation and testing.

In previous AA reviews, the AER's consultants concluded that the Core Energy forecasts were consistent with the above principles.

12.2 Customer and stakeholder engagement

We engaged with stakeholders (including retailers and our customers) in respect of our demand forecasts (see Table 12.1).

We discussed the key drivers of demand at our SARG and RRG meetings, and at one-on-one meetings with customers. We also conducted a survey with major customers to ensure we understood their business needs and demand requirements.

Stakeholders were keen to understand our approach and ensure that we had appropriately forecast growth.

Stakeholders indicated they understood and supported our approach to forecasting and noted that the approach is consistent with that adopted for our recent reviews, including our last SA review. Retailers indicated that trends shown in demand forecasts are consistent with their own observations and expectations of demand.

Following Draft Plan publication in February 2020, stakeholders expressed concern about the potential impacts that COVID-19 could have on our demand forecasts. In June we updated stakeholders that our demand and growth capex forecasts have been updated to include with new Housing Industry Association (HIA) forecasts which include the most recent view of the impact of COVID-19 on housing starts.

12.3 Residential and Commercial Demand

There are currently around 450,000 Residential and 11,000 Commercial customers that are connected to the South Australian gas distribution network.

The method that Core Energy has used to forecast demand and connections for the residential and commercial sectors is broadly the same, reflecting the fact they share the common key drivers of weather and gas price. The forecasting method that Core Energy has employed for our residential and commercial customers is therefore discussed jointly below.

Table 12.2 describes these customer groups and compares to the industrial customer group (our third customer group).

The three customer groups have different characteristics, which are taken into account when Core Energy produces their forecasts. The major difference is that Residential and Commercial customers are charged on the basis of units of energy used whereas Demand (Industrial) customers are charged on the basis of the capacity they require. This will be explained further in Section 12.4.2 below.

[1] NGR 74

Table 12.1: Summary of customer and stakeholder engagement outcomes - Demand

Demand	
Customer and Stakeholder Feedback	**Our Response**
Stage 1 and 2 Engagement : Developing our Plans	
Stakeholders noted AGN's approach to demand forecasting is based on historic trends with adjustments for projected energy prices, weather and dwelling construction starts. Retailers acknowledged the trend shown in demand forecasts are consistent with their own observations and expectations of demand.	• Our demand forecast applies methodologies accepted by the AER for our most recent South Australian and Victorian reviews. Our forecasting approach is also consistent with the approach adopted by the Australian Energy Market Operator (AEMO) in the Gas Statement of Opportunities.
Stage 3 Engagement : Draft Plan Consultation ⇨ Do you support our approach to forecasting demand? ⇨ Are there any other factors you think we should consider?	
Some stakeholders are concerned that should COVID-19 reduce demand for gas, a corresponding increase in gas prices will have negative outcomes (particularly for vulnerable customers). Stakeholders queried how AGN accounts for changes in the electricity market (e.g. batteries, solar, virtual power plants influencing demand for gas).	• We provided additional information on demand forecasting and noted that our demand model accounts for price elasticity and virtual power plants. • Our demand and growth capex forecasts will be updated with new HIA forecasts.
Stage 4 Engagement : Refining our Plans	
SARG and RRG support our proposed approach to demand, noting the information provided in relation to the potential impacts of COVID-19 on demand.	• Our demand forecasts are included in Chapter 12 of this Final Plan.
Final Plan Outcome	
✔	Our approach to developing the demand forecast applies methodologies accepted by the AER for our most recent South Australian and Victorian reviews and is supported by stakeholders. The residential customer number growth reflects the Housing Industry Association's projection of housing starts, including the HIA's most recent view of the impact of COVID-19 on housing starts.

Table 12.2: Forecasts prepared by Core Energy

Customer Class	Description	Forecast Prepared by Core Energy		
		Customer Numbers	Volume	MDQ
Tariff R – Residential	These are residential customers who consume less than 10 terajoules per annum.	Yes	Yes	Not required
Tariff C – Commercial	These are network users who consume less than 10 terajoules per annum and are commercial or small business customers.	Yes	Yes	Not required
Tariff D – Demand	Tariff D comprises customers who consume more than 10 terajoules per annum. These customers are charged based on a capacity signal and are generally industrial facilities.	Yes	Yes	**Yes**

Figure 12.1: Forecasting method used for residential and commercial customers

Step 1
Normalise historic data

a. Normalise the historic demand per connection data for both residential and commercial customers to remove fluctuations due to weather.
b. Use the normalised data to calculate an historic annual average growth in demand per connection.
c. Adjust for the effect of energy price changes from the historic growth.

Step 2
Forecast demand per connection

Determine the forecast demand per connection by adjusting the normalised data in Step 1 to account for drivers that are not reflected in the historic data, i.e. future energy price movements.

Step 3
Forecast connections

Derive a forecast of the net connections that will occur in the next AA period for residential customers (largely based on forecast new dwelling growth) and commercial customers (largely based on forecast economic activity).

Step 4
Forecast demand

Determine the forecast demand for both residential and commercial customers by multiplying the forecast consumption per connection from Step 2 by the total forecast connections for each customer group from Step 3.

12.3.1 How our forecasts were developed

The method Core Energy has used to forecast our residential and commercial customers' demand is summarised in Figure 12.1.

The method depicted in Figure 12.1 is consistent with the approach that was used to develop the demand forecasts for the current AA period for both our South Australian, Victorian and Albury networks. This approach was approved by the AER and is also consistent with the principles employed by the Australian Energy Market Operator (AEMO), when forecasting residential and small commercial demand for its Gas Statement of Opportunities (GSOO).

Further detail on some of the key elements of this method is provided below.

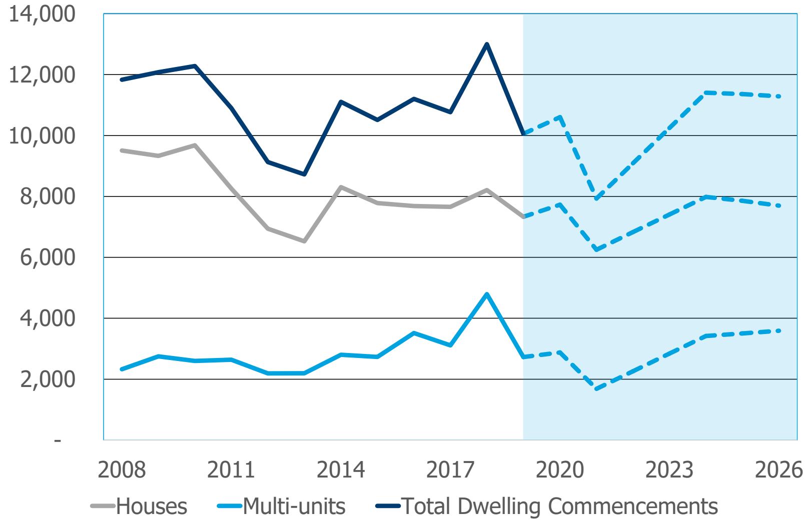
Weather adjustment

Our residential and commercial customers' demand for gas is strongly affected by weather, with customers using more gas when it is colder to heat their homes and businesses and vice versa in warmer weather. An adjustment for weather must therefore be made to historic residential and commercial demand to ensure the starting point and historic trends used to forecast gas demand are not unduly affected by abnormal weather conditions (see Step 1(a)) in Figure 12.1.

Core Energy has weather normalised demand according to AEMO's forecasting guidelines and in particular the application of the Effective Degree Days (EDD_{312}) methodology.

The EDD_{312} methodology takes into account three additional climatic factors when compared to a similar measure:

Figure 12.2: HIA actual and forecast dwelling commencements in South Australia



- Heating Degree Days (HDD), i.e. Sunshine Hours;
- wind chill; and
- seasonality.

When these three additional factors are taken into account, a greater relationship between the EDD_{312} measure and natural gas demand can be observed. Accordingly, consistent with the AEMO and its measurement of effective degree days, Core Energy has employed the EDD_{312} methodology due its close correlation to actual gas consumption.

Gas demand data has been regressed separately using historical EDD data between 2005 and 2019, which allows for a statistical relationship between weather and gas demand to be obtained.

This approach enables Core Energy 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 can be used for forecasting purposes.

Energy prices

In addition to weather, our residential and commercial customers' demand for gas is affected by changes in retail gas and electricity prices. An adjustment must therefore be made to the historic growth in consumption per connection to remove these effects (see Step 1(c)) in Figure 12.1.

An adjustment must then be made to the forecast demand per connection to reflect the forecast movement in retail gas and electricity prices.

To incorporate the effect of these prices on both the historic data and forecast demand for gas, estimates are required of:

- the responsiveness of gas demand to a change in retail gas prices (referred to as 'own price elasticity'); and
- the responsiveness of gas demand to retail electricity prices (referred to as 'cross price elasticity').

The elasticity values Core Energy has assumed are the same as those used in our last AA, which are as follows:

- Own-price elasticity: a lagged long-term-own-price elasticity estimate of -0.12% for residential and -0.43% for commercial customers has been assumed. This implies that a 1% increase in retail gas prices will result in a 0.12% and 0.43% reduction in consumption per connection for residential and commercial customers, respectively.
- Cross-price elasticity: a long-term-cross-price elasticity of negative -0.09% for residential and -0.08% has been assumed (this implies that a 1% increase in retail electricity prices will result in a 0.09% and 0.08% decrease in consumption per connection respectively).

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 South Australia.

This aspect of Core Energy's forecast is based on an independent forecast of new dwelling commencements by the Housing Industry Association (HIA) (see Figure 12.2).

HIA data (Figure 12.2) shows a decline in new dwelling commencements, particularly multi-unit dwellings, in 2018-19, followed by a small recovery in 2019/20. HIA released its most recent forecast of dwelling commencements in May 2020 outlining the impacts of COVID-19. This forecast shows a short-term decline in the number of detached and multi-unit dwellings to be constructed in South Australia. Core have reflected this short-term decline in their forecast.

The longer-term economic impacts will only be known as the impacts of the COVID-19 pandemic become clearer. We will update our forecasts when/if new information becomes available.

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 31 December 2019, there were approximately 3,000 zero consuming meters on the South Australian network, of which around 90% are residential meters. These meters have not had any consumption recorded since as far back as 1 July 2017.

A retailer also made a submission on Jemena Gas Networks' AA proposal in August 2019 seeking to have a number of these zero consuming meters disconnected. We expect that retailers in South Australia may make a similar submission on this Final Plan.

We expect these 3,000 meters will be removed from the network by 30 June 2022. The planned removal of zero consuming meters reduces total connection forecasts and hence increases consumption per connection forecasts as total consumption remains constant.

Core have assumed that half of these meters will be removed in the final year of the current AA period and the remainder removed in the first year of the next AA period.

12.3.2 Residential demand forecast

Using the methodology set out above, Core Energy has developed its forecast of residential demand in the next AA period by multiplying the forecast number of residential connections by forecast consumption per connection.

Residential connections

Core Energy is projecting that our residential connections (net of forecast disconnections)[2] will grow by 1.0% per year in the next AA period, reaching 476,549 by the end of the period (see Figure 12.3).

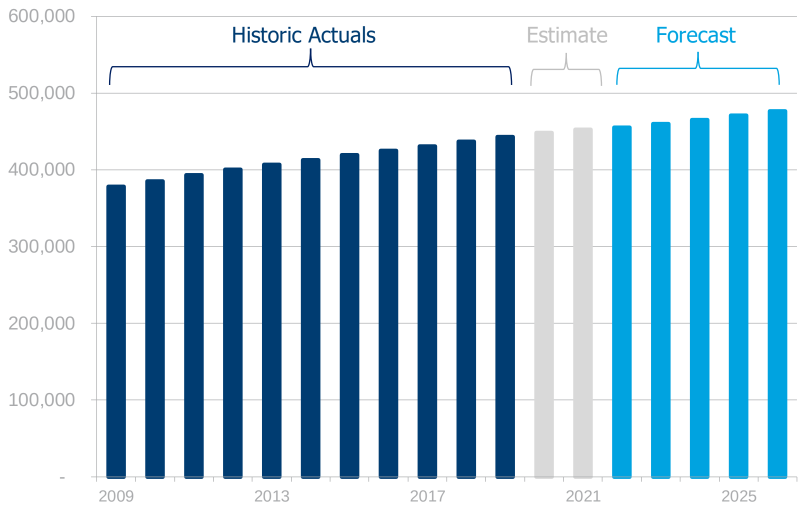
Existing connections are treated as the existing customer base less forecast disconnections. Core then overlays a new connections forecast over the existing connections forecast to derive a forecast of total residential customer numbers.

As noted earlier, new connections are forecast by estimating total new dwellings in South Australia with reference to the HIA forecast and then estimating the proportion of those dwellings that will connect to the network using an historical penetration rate.

The split of the total dwelling forecast between detached houses and Medium Density/High Rise (MDHR) apartments or townhouses is then determined. MDHR growth is forecast to be higher than detached dwellings.

It is unclear what effect the economic outcomes of COVID-19 will have on natural gas demand. We will monitor this in conjunction with Core Energy and reflect any required adjustments when/if further information becomes available.

Figure 12.3: Residential connections forecast (no.)



The forecast growth in residential connections is slightly lower than the 10-year historic average growth rate of 1.6% per year. This is due in large part to:

- lower forecast growth in new dwellings as shown in (see Figure 12.2);
- a short-term reduction in the number of new dwellings constructed in South Australia due to the impact of COVID-19;
- a reduction in the number of projected electricity to gas connections; and
- a small increase in the number of disconnections.

With regard to the first point, this lower forecast growth is largely driven by lower forecast economic activity and population growth in South Australia over the next AA period.

We have also added the connections and consumption we expect as a result of our extension to Mount Barker. The Mount Barker data are not included in the Core Energy forecast as Mount Barker is a new extension and there is no historical demand data. The Mount Barker connections and consumption data was added to our forecast reflecting the AER's Final Decision on the Mount Barker extension for the Residential, Commercial and Industrial segments.

Consumption per connection

Core Energy is projecting that consumption per residential connection will fall by around 2.6% over the next AA period, from 15.5 GJ in 2020/21 to 13.9 GJ in 2025/26.

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[2] The forecast number of disconnections is based on the application of the 10-year historic disconnection rate to total connections.

As Figure 12.4 shows, this fall is consistent with the long-term decline in average residential consumption per connection that has occurred in the last two AA periods. It is also consistent with what has occurred across our other distribution networks.

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. For further information on this trend see Attachment 9.3). It also reflects the expected increase in wholesale gas prices over the period.

Total residential demand

Overall, the demand for gas by our residential customers in the next AA period is expected to fall by 1.5% per year from 7,061TJ in 2021/22 to 6,603TJ in 2025/26 (see Figure 12.5).

This fall reflects the effect of the forecast decline in consumption per residential connection, which is partially offset by growth in residential connections.

The resultant residential demand forecasts are shown broken down into their components of net customer numbers (Figure 12.3), consumption per connection (Figure 12.4) and total demand in gigajoules (Figure 12.5).

Figure 12.4: Residential consumption per connection forecast (GJ)

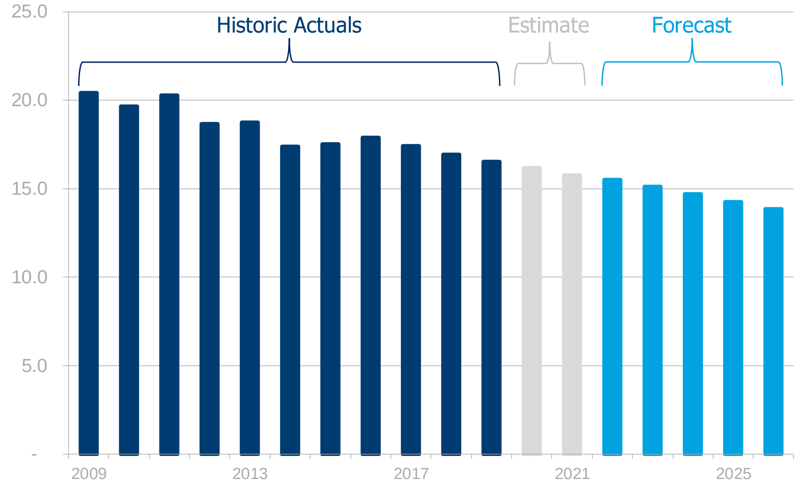
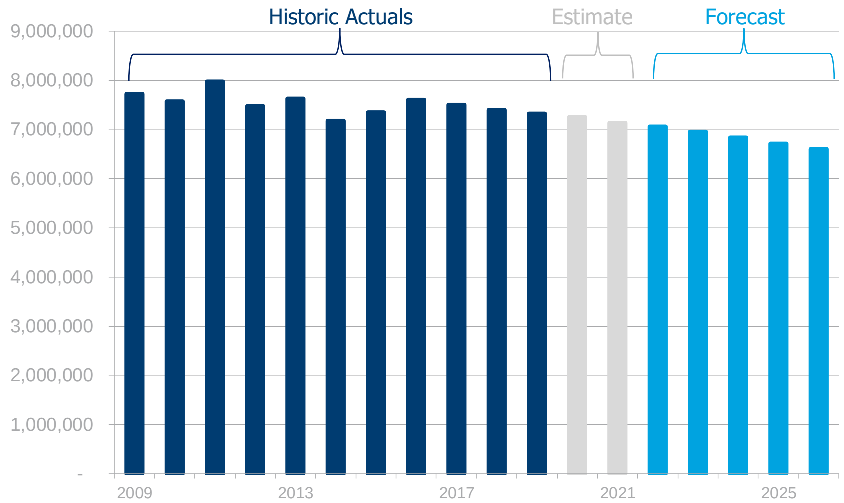


Figure 12.5: Total residential demand forecast (GJ)



12.3.3 Commercial demand forecast

Like residential demand, Core Energy's commercial demand forecast is calculated by multiplying the forecast number of commercial connections by the forecast consumption per commercial connection.

Commercial connections

In the next AA period, Core Energy is projecting the number of commercial connections (net of disconnections) will grow by 0.6% per year (see Figure 12.6) - lower than the historic trend due to a declining ratio of business numbers to real GSP. [3] Core Energy will update inputs to the forecast including updated GSP to reflect the impact of COVID-19 when/if new information becomes available.

Consumption per connection

In a similar manner to our residential customers, the average consumption per commercial connection is expected to decline in the next AA period, primarily as a result of higher wholesale gas prices (see Figure 12.7).

The decline is less than for our residential customers due to the slower historic trend decline in consumption per connection. Consumption per commercial customer is forecast to fall by 0.3% per year over the next AA period, from 299 GJ in 2021/22 to 292 GJ in 2025/26.

Figure 12.6: Commercial connections forecast (no.)

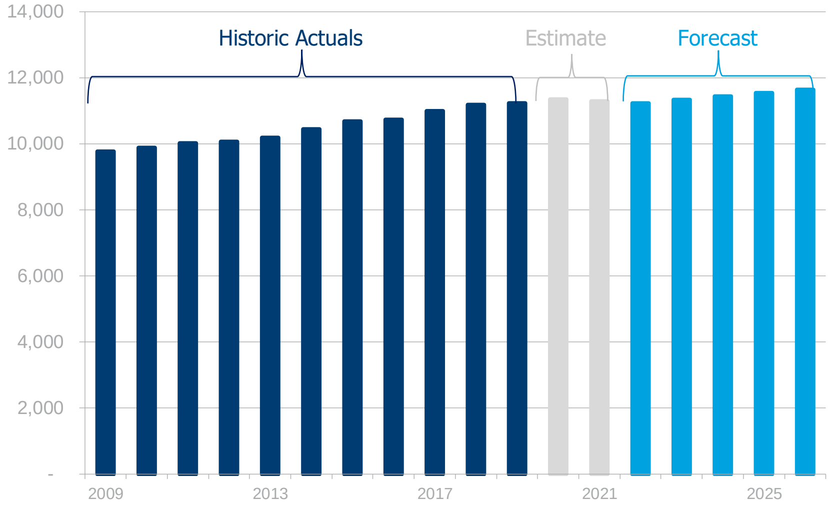
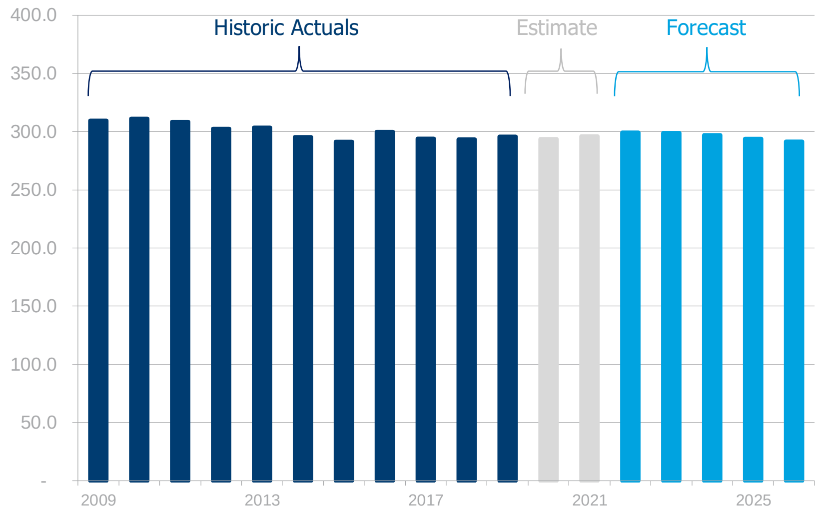


Figure 12.7: Commercial consumption per connection forecast (GJ)



[3] State Government of South Australia, State Budget 2019-20, Budget Paper 3, https://www.statebudget.sa.gov.au/budget-docs/2019-20_budget_statement.pdf

Total Commercial demand

The total demand for gas from commercial customers is expected to increase by 0.3% per year over the next AA period, from 3,361TJ in 2021/22 to 3,394TJ in 2025/26 (see Figure 12.8 and Table 12.3).

12.4 Industrial demand

12.4.1 How our forecast was developed

In contrast to residential and commercial customers, our industrial customers are charged on the basis of the capacity they are expected to require on a day. The forecast demand for this group is therefore based on both:

- the maximum amount of capacity that our industrial customers are expected to require on a day (referred to as Maximum Daily Quantity (MDQ)); and
- the total amount of gas that our industrial customers are expected to consume in a year (referred to as Annual Contract Quantities (ACQ)).

To help inform this forecast, we conducted a survey of our largest 25 industrial customers by capacity. The objective of the survey was to better understand their future MDQ and ACQ requirements, including any planned connections or disconnections over the next AA period. In total 10 customers responded to the survey.

Figure 12.8: Total commercial demand forecast (GJ)

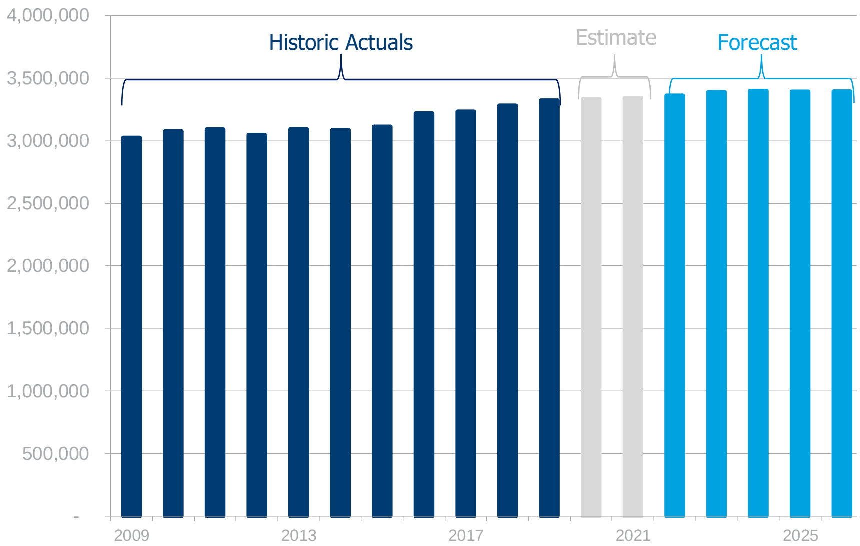
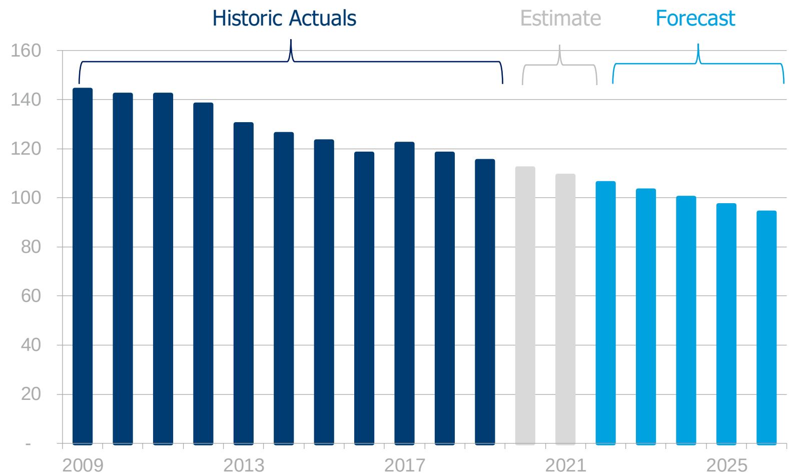


Figure 12.9: Industrial Connections Forecast (no.)



For those customers that did not respond to the survey, Core Energy examined the relationship between each customer's historic demand and economic activity. It did this by dividing the Industrial customer base into cohorts based on their ANZSIC codes, which are codes used by the Australian Bureau of Statistics to classify different industries.

Industrial demand driven by economic factors

In those cases where there is a strong relationship between the industrial group's natural gas demand and economic factors, the MDQ and ACQ is forecast by applying an adjustment to the historic demand based on forecast economic growth. This economic growth is estimated using a combination the Gross State Product of South Australia (GSP) and another measure known as

Gross Value Add (GVA) which is a measure of economic output.

Examples of customer groups that were driven by economic factors were:

- Information Media and Communications;
- Retail Trade; and
- Electricity, Gas, Water and Waste Services.

In those cases where there was not a statistically significant relationship, the MDQ and ACQ were forecast by applying an adjustment based on the historic trend.

Industrial demand driven by weather

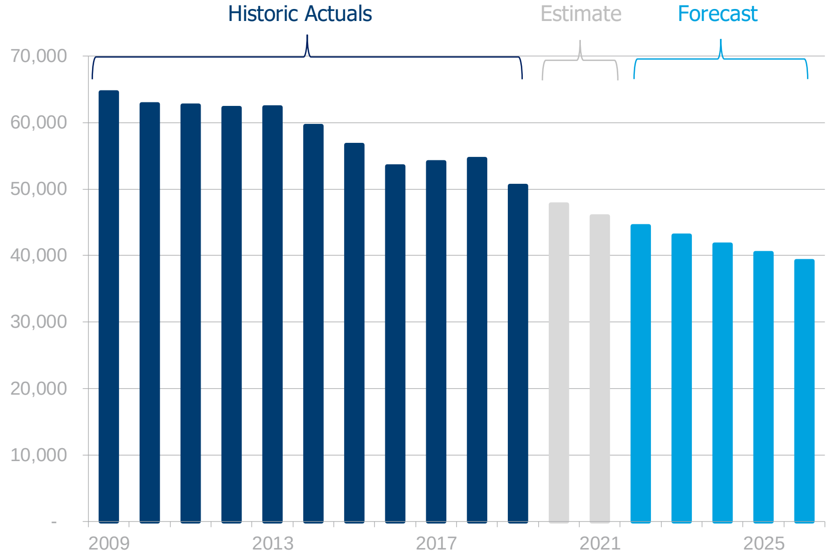
Core Energy also weather normalised a portion of the Industrial customers whose natural gas demand had a strong relationship to weather. The portion of Industrial customers that exhibited a strong demand response to different weather patterns were weather normalised.

For example, the Health and Social Assistance and Accommodation and Food Services sectors have a peak in the winter as gas space heating demand peaks and summer when gas air conditioning in large retail spaces is used.

Industrial Connections

The connections forecast for industrial customers has been developed having regard to historic growth estimates and information on known new connections and disconnections (see Figure 12.9). The disconnections data was informed by our survey of the top 25 Industrial customers which provided valuable data on those businesses who had plans to either increase or decrease consumption and/or capacity, or indeed leave the network in the future.

Figure 12.10: Industrial demand – MDQ (GJ)



12.4.2 Industrial demand forecast

Industrial MDQ is forecast to decline by 3.1% per annum to 39,174 GJ MDQ over the next AA period (see Figure 12.10). Industrial connections are also forecast to decline to 106 connections, from 113 at the start of the AA period.

12.5 AEMO Forecasts

AEMO produces annual forecasts of gas demand for the east coast gas market of Australia in the GSOO, the most recent report published in March 2020[4]. 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.

Both the AEMO and the Core Energy forecasts are predicting a decline in total demand for the residential and commercial segment.[5]

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.

[4] Australian Energy Market Operator, '2020 Gas Statement of Opportunities', https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo, 27 March 2020

[5] Ibid, 2020 GSOO report charts, Figure 7 (GSOO 2020 Central Case), South-Eastern Australia.

12.6 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 2018/19 volumes and an estimate of prices throughout the period. The ARS forecast is escalated in line with our operating expenditure (opex) forecast over the next AA period.

12.7 Summary

Table 12.3 provides a summary of our demand forecasts for the next AA period.

As this table shows, residential and industrial demand is forecast to decline over the next AA period whilst commercial demand is forecast to rise.

Our demand forecasts are based on the methodology accepted by the AER in the current AA period for both our South Australian, Victorian and Albury networks. The residential forecasts are driven by expected new dwellings growth in South Australia, as provided by the Housing Industry Association. This HIA forecast takes into account the impact of COVID-19 in the short-term.

Our industrial forecasts are based on the historical trend and the results of the survey of our top 25 industrial customers.

Table 12.3: Summary of the demand forecast (including Mount Barker)

	2021/22	2022/23	2023/24	2024/25	2025/26
Residential demand					
Connections (no.)	455,474	460,456	466,316	472,716	478,985
Consumption per connection (GJ)	15.5	15.1	14.8	14.3	13.9
Demand (TJ)	7,063,355	6,965,198	6,922,095	6,753,763	6,661,181
Commercial Demand					
Connections (no.)	11,236	11,350	11,472	11,590	11,707
Consumption per connection (GJ)	299.2	298.8	297.5	294.3	292.4
Demand (TJ)	3,361,719	3,391,168	3,412,492	3,411,364	3,423,292
Industrial Demand					
Connections (no.)	106	103	101	100	98
MDQ (TJ)	29,157	28,322	27,542	26,818	26,048
ACQ (TJ)	10,272,243	9,982,566	9,698,534	9,420,162	9,147,402

13 Revenue and Pricing

IN THIS CHAPTER:

We have proposed to cut South Australian network prices by 9% on 1 July 2021 followed by increases of 1.2% each year thereafter (expressed in real terms).

Price changes in this Chapter are expressed in real terms to align with the AER's model. The 9% real figure here is the same as the 7% nominal figure quoted elsewhere in this document.

This will save the average residential customer $34 per year, average commercial customer $335 per year and average industrial customer $17,400 per year.

Our proposed price path reflects the forecast growth of our capital base which will enable revenue growth commensurate with changes in our underlying costs.

We are proposing a 9% (real) cut in prices over the next AA period.

Our costs are referred to as 'building blocks' and are summed to determine total allowed revenue in each year of the next AA period.

We recover our costs through the prices (or tariffs) that we charge for reference services.

13.1 Regulatory Framework

Prices in this chapter are in real terms consistent with regulatory practice. Stakeholders who wish to see nominal prices and changes should refer to Chapter 4.[1]

We are required to determine total revenue for each year of the next AA period as the sum of our forecast opex, return on our capital base, depreciation of the capital base and an allowance for the cost of tax.[2]

Our total revenue can also increase or decrease depending on our performance in relation to incentive mechanisms applying in the current AA period, such as the opex incentive mechanism (Efficiency Benefit Sharing Scheme – EBSS) which applies to our South Australian gas network.

Our prices are required to reflect, to the extent possible, 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.

13.2 Customer and Stakeholder Engagement

Customers and stakeholders provided feedback that price and affordability are their highest priorities (Table 13.1). In developing our Final Plan we have paid particular attention to the impact individual aspects of the plan will have on price.

As part of our engagement on this Final Plan, we also sought feedback on our proposed price path.

The key feedback from the engagement program was that:

- 96% of our customers either supported or strongly supported our plans, including our 9% price cut on 1 July 2021; and
- stakeholders had differing preferences on our proposed price path, with some stakeholders supporting the larger upfront price cut as proposed, providing faster price relief, whilst others preferred the cuts be delivered evenly over the five-year period.

The price path proposed in this Final Plan is for a larger upfront price cut followed by increases in price in subsequent years reflecting the forecast growth in our RAB throughout the period.

[1] NB Price changes in this Chapter are expressed in real terms to align with the AER's model. For an overview of price changes that customers will see in their bill in nominal terms (i.e. after the impact of inflation) please see Chapter 4.

[2] NGR 76

Table 13.1: Summary of customer and stakeholder engagement outcomes – Revenue and pricing

Revenue and Pricing

Customer and Stakeholder Feedback	Our Response
Stage 1 and 2 Engagement : Developing our Plans	
Customers told us that price and affordability are their top priorities. Customers and stakeholders supported our proposed price cut. Customers were keen to understand how gas distribution prices are included in their final bill – and how any savings might be passed on by their retailer.	• Based on early modelling we proposed a price cut for our customers. In our Draft Plan 6% after the impact of inflation (or 8% in real terms as expressed at the time). In the first year of the next period, followed by real increases of 1.2% each year thereafter, consistent with the growth in our capital base. • We noted that we will engage with retailers to encourage the pass through of any savings to customers when our new prices take effect on 1 July 2021, the same way we did when our prices were cut by 21% at the start of the current period.
Stage 3 Engagement : Draft Plan Consultation ⇨ Have we provided enough information to understand the basis of our proposed price, including how it is split between the capacity and commodity components? ⇨ Is there anything that our Draft Plan hasn't considered that is important to you?	
Customers and stakeholders supported the proposed price cut of 6% (after inflation) in the Draft Plan. While some stakeholders indicated a preference for 'smoothing' (i.e. consistent price reductions each year), most stakeholders indicated a preference for AGN's current model. Some stakeholders suggested that AGN consider how the price path is communicated with customers more simply. Stakeholders queried how COVID-19 might impact AGN's revenue and debt costs (and by extension impact on price), noting that further assessment is required.	• We are proposing a larger price cut in year 1 followed by real increases as this was the preferred model by most customers and stakeholders. It also aligns the price path for years 2 to 5 with growth in our capital base and therefore funding costs. The proposed price path will also provide relief to customers impacted by COVID-19. • We committed to include more information in this Final Plan regarding price cuts and the price paths for residential, business and commercial customers in real terms.
Stage 4 Engagement : Refining our Plans	
SARG and RRG supported the 7% price cut (after inflation) and endorsed the proposed way in which AGN will be communicating the price impacts and price path for customers.	• Our approach to total revenue and proposed prices is included in Chapter 13 of this Final Plan. • In the Final Plan we communicate key price impacts after the impact of inflation in Chapter 4 (as opposed to in real terms).
Final Plan Outcome	
We are proposing an upfront price cut of 7% (after inflation) which builds on price cuts of 21% delivered at the beginning of the current AA period. Customers and stakeholders support our proposed price path and revenue.	

The COVID-19 pandemic has also had a significant economic and social impact for many South Australians that was reflected by customers and stakeholders. Therefore it was more important than ever that our Final Plan deliver network price relief.

13.3 Building Block Total Revenue

Our Final Plan has described the services we will provide (Chapter 6) and the costs 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 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).

Building block total revenue includes revenue from providing HRS and ARS. We therefore need to determine the proportion of building block total revenue that applies to ARS and HRS as these services have different pricing structures. We do this by determining building block total revenue inclusive and exclusive of ARS.

ARS are those services that are specifically requested by users. Table 13.2 sets out the ARS building block total revenue, which is determined by

Table 13.2: Forecast revenue from Ancillary Reference Services, 2021/22 to 2025/26 ($2020/21, million)

	2021/22	2022/23	2023/24	2024/25	2025/26
Special Meter Read	1.2	1.2	1.2	1.2	1.3
Disconnection	0.5	0.5	0.5	0.5	0.5
Reconnection	0.5	0.5	0.5	0.5	0.5
Meter Removal	0.2	0.2	0.2	0.2	0.2
Meter Reinstallation	0.0	0.0	0.0	0.0	0.0
Meter Gas and Installation Test	0.0	0.0	0.0	0.0	0.0
Total	**2.4**	**2.4**	**2.5**	**2.5**	**2.5**

Note: Totals may not add due to rounding

Table 13.3: Building Block Total Revenue, 2021/22 to 2025/26 ($nominal, million)

	2021/22	2022/23	2023/24	2024/25	2025/26
Return on Capital	83.4	83.2	83.1	82.9	82.6
Return of Capital	57.1	61.7	66.3	64.0	69.1
Opex	74.9	77.6	80.4	83.1	85.8
Incentive Mechanism	6.7	1.8	6.2	-1.8	-
Cost of Tax	-	-	-	-	-
Building Block Total Revenue (including ARS)	**222.1**	**224.4**	**236.0**	**228.2**	**237.6**
Less ARS	2.5	2.6	2.7	2.7	2.8
Building Block Total Revenue (excluding ARS)	**219.6**	**221.8**	**233.3**	**225.5**	**234.7**

Note: Totals may not add due to rounding

Table 13.4: Proposed Price Path, 2021/22 to 2025/26 ($nominal, million)

	2021/22	2022/23	2023/24	2024/25	2025/26
Building Block Total Revenue (excluding ARS)	219.6	221.8	233.3	225.5	234.7
Smoothed Revenue	213.6	220.1	228.1	233.6	241.0
Real Price Path	-8.67%	+1.25%	+1.25%	+1.25%	+1.25%

multiplying the forecast volume by the forecast price of providing ARS in each year. The forecast volume for these services matches the expected growth in customer numbers (see Chapter 11) while the price reflects the cost of providing each ARS.

This Final Plan outlines the basis of all the relevant building blocks that are used to determine building block total revenue. The building block total revenue with and without the cost of providing Ancillary Reference Services (ARS) is provided in Table 13.3.

Our building block revenue is recovered through the prices we charge retailers for providing domestic, commercial and demand haulage services and ARS. We are required to set our prices such that the total revenue we recover equals the building block total revenue in net present value (NPV) terms. The AER's Final Decision will provide for a series of price changes (or X-factors) to ensure this objective is achieved.

The building block total revenue, smoothed tariff revenue and percentage changes in prices are set out in Table 13.4.

We have developed our price path in order:

- to provide for revenue growth that approximates the real growth in the capital base over the next AA period, thus ensuring the growth in our revenue is commensurate with the forecast changes in our funding costs; and
- to equate tariff revenue as close as possible to our underlying costs in 2025/26 (the last year of the next AA period) thus ensuring a smoother price path between the next AA and subsequent AA periods.

By aligning our price path to the growth in our capital base we are more likely to sustain credit metrics at levels assumed by the AER in setting the return on debt. This is because our revenue will more closely match our underlying costs over time, including our contractual obligations (see Section 13.3.1).

13.3.1 Financeability of a pricing decision

The AER assumes a weighted average of credit ratings between A- (one third) and BBB+ (two thirds) when it sets the return on debt (as the assumed credit rating directly impacts borrowing costs). We therefore consider it is good regulatory practice to consider whether our proposal meets the credit metrics required of A-/BBB+ rated business.

The ratings agencies focus on the following two key credit metrics in determining a 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 costs).

FFO is calculated as total smoothed 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 ratio above 2.5 to determine a weighted average credit rating of between A- and BBB+. 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 an easier constraint to achieve).

We have assessed the key credit ratios delivered by our Final Plan (see Table 13.5). Our Final Plan delivers an average FFO to debt of 9.0% and FFO to interest of 3.2 over the next AA period, which satisfies the thresholds required for a weighted average A-/BBB+ rating. This reflects and supports

Table 13.5: Final Plan Key Credit Ratios, 2021/22 to 2025/26

	2021/22	2022/23	2023/24	2024/25	2025/26	Average
FFO to Debt	8.6%	8.8%	9.1%	9.1%	9.3%	9.0%
FFO to Interest Cover	2.8	3.0	3.2	3.3	3.6	3.2

our proposed price path shown in Table 13.3.

If key aspects of this Final Plan are adjusted and these thresholds are not met, our view is that an adjustment to our cash flow would be required over the next AA period. This adjustment would be required to maintain the credit rating assumed by the AER in setting the return on debt (thereby ensuring that the plan for the next AA period is internally consistent) and could include:

- varying the inflation adjustment that is used to calculate regulatory depreciation, with the lower inflation adjustment having the effect of increasing revenue (and hence cash flow) in the next AA period; or
- shifting the classification of spending from 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).

As this Final Plan satisfies the financeability metrics, we have not proposed these measures however if revenues in the Final Decision are lower than the Final Plan, the metrics would not be satisfied.

13.4 Prices

As already noted, we recover our revenue through the prices that we charge retailers for providing reference services. This section outlines our current and proposed pricing structures.

13.4.1 Current Pricing Structure

Our current pricing structure for residential and commercial haulage services includes two zones, South Australia (excluding Tanunda) and Tanunda.

Our demand haulage service for our largest industrial customers comprises 8 zones. This includes 3 zones in the Adelaide metropolitan area (the Central, Northern and Adelaide Southern zones) and five outside the Adelaide metropolitan area (Port Pirie, Riverland, South East, Peterborough and Whyalla).

Prices for residential and commercial customers consist of several volumetric (or consumption) based charging parameters (in dollars per GJ per day) and a fixed supply charge (in dollars per day).

In the residential and commercial segments we currently recover approximately 75% of our revenue in the variable (volumetric) components of our tariffs and 25% through the fixed components. This reflects previous customer and stakeholder feedback supporting a relatively higher degree of variability in their gas bill as it more closely reflects user-based pricing. This needs to be balanced against costs, which are predominantly fixed.

Prices for our demand customers are based on agreed capacity and consist of a number of banded charging parameters (in dollars per GJ of MDQ) (see Table 13.6).

All prices decline as usage increases to promote better network utilisation.

13.4.2 Tariff name change

We currently have two tariff zones in South Australia which apply to residential and commercial customers – Tanunda and South Australia (excluding Tanunda). The Tanunda zone was first introduced in 2011/12 reflecting the network extension to the town, and differs from the other tariff on account of a 30% increase applied to the volumetric component. This difference accounts for the significant upfront capital costs incurred bringing gas to a new area or town.

The Tanunda tariff will also apply to the Mount Barker network extension, and we note that this was used in the application to approve the extension. Therefore, we consider the tariff should be renamed to better align with the customer base.

We are proposing the names of the existing tariffs be changed to "New Towns" and "South Australia (excluding New Towns)". It is envisaged the "New Towns" tariff could also apply to other significant network extensions in the future.

13.4.3Allocation of Revenue and Costs

The costs set out in this Final Plan, particularly those set out in Chapters 7 (Operating Expenditure) and 8 (Capital Expenditure), relate to the provision of HRS and ARS, which are collectively referred to as Reference Services. The costs incurred in providing Non-reference Services are directly incurred and recovered from the particular customer that requested the service, and as such, are not included in this Final Plan.

As explained in Section 13.3, the costs we incur by providing ARS are directly recovered from the customers requesting the service. ARS form around 1% of the total revenue we recover from customers. The remaining revenue is recovered from HRS and includes:

- Domestic Haulage Service – this service provides for the delivery of gas to Delivery Points (DPs) where gas is used primarily for domestic purposes;
- Commercial Haulage Service – this service applies to all DPs that are not Demand DPs or Domestic DPs; and
- Demand Haulage Service – this service provides for the delivery of gas to Delivery Points (DPs) with an annual consumption that is equal to or greater than 10 terajoules per year.

We have developed a tariff cost allocation model (TCAM) to allocate revenue to each HRS. The TCAM, which is provided as Attachment 13.2, sets out the basis of the allocation of costs between the three HRS. The TCAM allocates the HRS building block revenue (excluding ARS) to each tariff class based on a number of different cost allocators, which include a combination of asset values, customer numbers and consumption. The allocators selected are used to estimate available of the cost for servicing each tariff class.

Also explained in Attachment 13.1 is that the revenue we recover from each tariff class lies on or between an upper bound (representing the stand alone cost of providing the reference service to the customers who belong to that tariff class) and a lower bound (representing the avoidable costs of not providing the reference costs to those customers).

As expected, there has been no material change in cost allocation between the HRS for the next AA period. Rather, we have updated the previous approach to cost allocation that was approved by the AER for the current AA period for current cost (or building block)

Table 13.6: Charging Parameters by Customer Type

Residential (Tariff R)	Commercial (Tariff C)	Industrial (Tariff D)
Fixed Charge	Fixed Charge	0 – 50 GJ MDQ
0-10 GJ	0-360 GJ	50-100 GJ MDQ
10-18 GJ	360-1,920 GJ	100-1000 GJ MDQ
>18 GJ	1,920-6,000 GJ	Additional GJ MDQ
	>6,000 GJ	

information provided throughout this Final Plan.

13.4.4 Declining Block Tariff Structure

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 by promoting connection of more gas appliances, which is part of the package of measures that we use to address the observed long-term decline in demand per connection (see Chapter 11).

For instance, our first residential pricing band broadly captures a customer using a gas cooker and solar hot water system, the second step captures a customer with a non-solar gas hot water system while the final step captures customers utilising gas for space heating.

Both Tariff R and Tariff C Reference Tariffs consist of several volumetric (or consumption) based charging parameters (in dollars per gigajoule per day). Tariff R will comprise the following three volumetric charging bands:

- a charge for the first 0.0274 gigajoules of gas delivered (dollars per gigajoule) – equating to 10 gigajoules per annum;
- a charge for the next 0.0219 gigajoules of gas delivered (dollars per gigajoule) – equating to the next 8 gigajoules per annum; and
- a charge for additional gas delivered (dollars per gigajoule).

Tariff C will maintain the following four volumetric charging bands:

- a charge for the first 0.9863 gigajoules of gas delivered (dollars per gigajoule) – equating to 360 gigajoules per annum;
- a charge for the next 4.274 gigajoules of gas delivered (dollars per gigajoule) – equating to the next 1,560 gigajoules per annum;
- a charge for the next 11.178 gigajoules of gas delivered (dollars per gigajoule) – equating to the next 4,080 gigajoules per annum; and
- a charge for additional gas delivered (dollars per gigajoule).

As explained above, both the Tariff R and Tariff C classes are structured as 'declining block tariffs'.

We consider our pricing structures align with our obligations that require AGN to promote the efficient use of the network. We therefore consider there is strong merit in retaining the existing declining pricing structure and propose that it be retained in the next AA period.

13.4.5Haulage Reference Service Tariff Classes

We are required to allocate customers for the three HRS into tariff classes. Customers are assigned to a particular tariff class within a HRS on the basis of their geographic location. The list of tariff classes is shown in Table 13.7.

13.4.6Tariff R and Tariff C

As described in section 13.4.2, The Tariff R – Residential and Tariff C – Commercial tariff classes both comprise two tariff categories based on geographic location. The first category captures all residential customers in South Australia, excluding Tanunda and Mount Barker. A separate tariff was approved by the AER in the previous AA period for customers connected to the newly built network in Tanunda.

The Tariff R and Tariff C Reference Tariffs comprise the following charging parameters:

- supply charge (in dollars per day); and
- banded volume charges (in dollars per gigajoule per day).

Supply Charge

The supply charge is a fixed daily charge that applies to all DPs and is designed to:

- reflect the predominantly fixed-cost nature of gas distribution; and
- signal each customer's connection costs, having regard for the size, location and type of network user.

Banded Volume Charges

Banded volume charges are described in section 13.4.4

Table 13.7: South Australian Tariff Classes

Haulage Reference Service	Tariff Class	Proposed Tariff Name	Geographical Zone
Domestic	Tariff R – Residential	Residential (excluding New Towns)	All (excluding Tanunda and Mount Barker)
Domestic	Tariff R – Residential	Residential – New Towns	Tanunda and Mount Barker
Commercial	Tariff C – Commercial	Commercial (excluding New Towns)	All (excluding Tanunda and Mount Barker)
Commercial	Tariff C – Commercial	Commercial – New Towns	Tanunda and Mount Barker
Demand	Tariff D – Northern	Tariff D	Adelaide North
Demand	Tariff D – Central	Tariff D	Adelaide Central
Demand	Tariff D – Southern	Tariff D	Adelaide South
Demand	Tariff D – Peterborough	Tariff D	Peterborough
Demand	Tariff D – Port Pirie	Tariff D	Port Pirie
Demand	Tariff D – Riverland	Tariff D	Riverland
Demand	Tariff D – South East	Tariff D	South East
Demand	Tariff D – Whyalla	Tariff D	Whyalla

13.4.7Tariff D - Demand

The structure of the demand tariff classes consist of a number of banded Maximum Daily Quantity (MDQ) charging parameters (in dollars per gigajoule of MDQ per day). The first band effectively represents a fixed charge as a minimum chargeable MDQ applies. Consistent with the volume tariffs, Tariff D Reference Tariffs are structured as 'declining block tariffs', whereby the charges decrease as MDQ increases (again, designed to increase network utilisation).

The MDQ charges are capacity-based charges, which is intended to reflect the key cost driver in supplying demand customers. The structure provides economic signals to demand customers to have a smooth consumption profile as opposed to a 'peaky' profile. A flat profile results in improved network utilisation and therefore lower costs in providing reference services (as the capacity/size of the network required to supply a particular volume will be lower).

The locational aspect of Tariff D reflects the different cost of supplying customers and is designed to encourage demand customers to locate in those parts of the network that will impose the least costs on AGN (and hence customers). This lower cost is then factored into the determination of the Reference Tariffs for existing customers on the network and will, all else equal, result in lower Reference

Tariffs for customers in subsequent AA periods.

The proposed Tariff D structure is identical to the structure in the current AA period.

13.4.8 Ancillary Reference Services

ARS tariffs reflect the operating expense of providing these services. Each tariff reflects the actual cost of providing each service and therefore delivers the appropriate price signal.

13.5 Form of revenue control and tariff variation mechanism

We are proposing to maintain the same form of revenue 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).[3] 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 13) plus an adjustment factor.[4]

The form of revenue control and resultant tariff variation is explained and detailed further in Attachment 13.1.

13.6 Summary

We recover our regulated revenue by charging Reference Tariffs to customers for HRS and ARS. All proposed tariffs have the same structure as that applying over the current AA period and fall between the stand alone and avoidable costs of providing services to our customers.

The proposed tariffs to take effect as at 1 July 2021 are detailed in Table 13.8, Table 13.9 and Table 13.10.

Our proposed tariffs cut our network prices in South Australia by 9% (before inflation) on 1 July 2021 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.

Attachment 13.1 provides further details on the tariff structures adopted. This attachment demonstrates that the tariff structures adopted are efficient and contain no cross subsidy. It also demonstrates other factors we have considered such as transaction costs, the LRMC and the ability for consumers to respond to price changes.

We propose that a weighted average price cap apply for the next AA period consistent with what applies in the current AA period. Further details are available in Attachment 13.1 also discusses the tariff variation mechanism.

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 A-/BBB+ credit rating assumed by the AER in setting the return on debt. We have done this and consider that, given we are just at required threshold requirements, if some aspects of this Final Plan are not accepted, 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 in this Final Plan.

[3] The WAPC is a form of tariff basket control, and as such, is consistent with Rule 97(2)(b) of the NGR.

[4] Consistent with the current AA period, we are proposing to increase ARS by the CPI only.

Table 13.8: Tariff R and C Domestic Haulage Service Tariffs ($Nominal)

Charges per Network Day (excluding GST)	
Tariff R (excluding New Towns)	
Base Charge ($ per day)	0.2984
Charge for the first 0.0274 gigajoules of gas delivered ($ per gigajoule)	30.5518
Charge for the next 0.0219 gigajoules of gas delivered ($ per gigajoule)	10.8537
Charge for additional gas delivered ($ per gigajoule)	3.6743
Tariff C (excluding New Towns)	
Base Charge ($ per day)	0.6287
Charge for the first 0.9863 gigajoules of gas delivered ($ per gigajoule)	15.0681
Charge for the next 4.2740 gigajoules of gas delivered ($ per gigajoule)	6.0062
Charge for the next 11.1780 gigajoules of gas delivered ($ per gigajoule)	2.5946
Charge for additional gas delivered ($ per gigajoule)	2.0081
Tariff R (New Towns)	
Base Charge ($ per day)	0.2984
Charge for the first 0.0274 gigajoules of gas delivered ($ per gigajoule)	39.7173
Charge for the next 0.0219 gigajoules of gas delivered ($ per gigajoule)	14.1098
Charge for additional gas delivered ($ per gigajoule)	4.7766
Tariff C (New Towns)	
Base Charge ($ per day)	0.6287
Charge for the first 0.9863 gigajoules of gas delivered ($ per gigajoule)	19.5885
Charge for the next 4.2740 gigajoules of gas delivered ($ per gigajoule)	7.8081
Charge for the next 11.1780 gigajoules of gas delivered ($ per gigajoule)	3.3730
Charge for additional gas delivered ($ per gigajoule)	2.6105

Notes to Table 13.8:

- The total daily Charge will comprise the Base Charge plus a Charge for the Quantity of Gas delivered (or estimated to have been delivered) through the Domestic Delivery Point.
- The Charge for the Quantity of Gas delivered (or estimated to have been delivered) through the Domestic Delivery Point will be calculated at the rates shown in the table.
- A reference in the table to the Gas delivered through the Domestic Delivery Point is a reference to Gas delivered through the Domestic Delivery Point whether for the account of the Network User or for the account of any other person or persons.
- Charges will be calculated to the nearest four decimal places.

Table 13.9: Tariff D Demand Haulage Service Tariffs $Nominal

Adelaide Region	Northern Zone	Central Zone	Southern Zone	
50 gigajoules or less	$2,605.8981	$2,605.8981	$2,605.8981	
Next 50 gigajoules ($ per gigajoule)	$50.6700	$60.1742	$70.9637	
Next 900 gigajoules ($ per gigajoule)	$31.6331	$38.2680	$44.4423	
Additional gigajoules ($ per gigajoule)	$9.5846	$10.9666	$13.4026	
Other Regions	**Port Pirie**	**Riverland**	**South East**	**Whyalla**
50 gigajoules or less	$2,605.8981	$3,678.2873	$2,605.8981	$2,605.8981
Next 50 gigajoules ($ per gigajoule)	$50.6692	$73.9844	$50.6692	$50.6692
Next 900 gigajoules ($ per gigajoule)	$17.5602	$46.1019	$26.1527	$26.1527
Additional gigajoules ($ per gigajoule)	$8.8234	$9.5846	$9.5846	$9.5846

Notes to Table 13.9:

- The Demand Haulage Charges shown above are charges for a complete calendar month.
- The Charge for a calendar month will accrue from day to day in equal portions.
- Charges will will be calculated to the nearest four decimal places..
- For the purpose of calculating daily overrun charges pursuant to Clause 5 of the General Terms and Conditions, the overrun rate is $15 per gigajoules (excluding Goods and Services Tax).

Table 13.10: Ancillary Reference Services Tariffs $2021/22

Tariff Class	
Special Meter Read	$11.30
Disconnection	$77.00
Reconnection	$77.00
Meter Removal	$77.00
Meter Reinstallation	$83.00
Meter Gas and Installation Test	$230.00

14 Network Access

IN THIS CHAPTER:

We have continued standardising our terms and conditions across our networks.

Our AA Document will remain consistent with the AA Document applicable in the current period

We are continuing the process of standardising our proposed terms and conditions across Australia.

Our reference service terms and conditions set the contractual arrangements between AGN and network users.

A key part of our relationship with network users is the contractual agreement that governs the conditions (or terms) of access to our networks, commonly referred to as a 'Haulage Agreement'.[1] The terms and conditions of the Haulage Agreement typically reflect the AER approved terms that are set out in our AA Document, unless otherwise agreed by the parties.

The following sections outline the processes followed to develop our proposed terms of access to our South Australian gas distribution network over the next (2021/22 to 2025/26) AA period.

We also describe the changes we are proposing to the terms and conditions from those in place during the current (2015/16 to 2021/22) AA period. The terms and conditions are set out in our AA Document, which will be provided alongside the Final Plan to be submitted to the AER by 1 July 2021.

14.1 Regulatory Framework

We are required under the NGR to specify the terms and conditions on which each reference service will be provided in our Final Plan.[2]

14.2 Customer and stakeholder engagement

Our terms and conditions have been subject to considerable stakeholder engagement through a number of successive AA review processes (see Table 14.1). As a result our terms have been amended over time to take into account the 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 network over the next AA period.

We have engaged further with retailers on the proposed terms to apply to our South Australian network leading into developing our Final Plan. This engagement has occurred primarily through our Retailer Reference Group (RRG), which comprises representatives of retailers that operate in South Australia.

Our engagement on the proposed terms commenced in 29 April 2019, as highlighted in Section 5.1 and in Attachment 14.1.

'AGN continues to set the benchmark standard of consultation with industry in its AA reviews. Furthermore, we support AGN's efforts to try and align the terms and conditions of access for their SA AA with Victoria to the extent possible.'
Red Energy and Lumo Energy Submission to our Proposed General Terms and Conditions

[1] Network users are primarily gas retailers or self-contracting users of our networks.

[2] NGR 48(1)(d)(ii))

Table 14.1: Summary of customer and stakeholder engagement outcomes – Network access

Network Access

Customer and Stakeholder Feedback	Our Response
Stage 1 and 2 Engagement : Developing our Plans	
We distributed draft terms and conditions in June 2019. We received feedback from three retailers on the first draft.	• We noted the process that commenced 10 years ago to standardise our terms and conditions across all our networks. To this end, we started with our current terms and conditions as a base which includes the outcomes of previous engagement and AER decisions. • Feedback was incorporated into the second draft of the terms and conditions which were provided to members of our Retailer Reference Group in December 2019. • We committed to continuing to provide opportunities for retailers to comment on our proposed terms and conditions as part of stages 3 and 4 of our engagement program.
Stage 3 Engagement : Draft Plan Consultation ⇨ Do you support AGN continuing to standardise terms and conditions across its network?	
We received two retailer submissions on terms and conditions regarding changes to customer details, credit support, time limits, disclosure to associated companies, best endeavors to read meters and users procuring gas through market mechanisms. We also received communication from another retailer seeking alignment with the Australian Energy Market Operator's Retail Market Procedures. We received a submission supporting our approach to continuing to standardise terms and conditions across our networks.	• We provided responses addressing all the feedback on terms and conditions.
Stage 4 Engagement : Refining our Plans	
We continued to discuss our draft terms and conditions focusing on the new customer details clause. SARG and RRG support the standardisation of our terms and conditions across our networks.	• In response to feedback, we have modified the proposed customer details clause in the third version of the proposed terms and conditions. The customer details clause is now a general clause in line with the recently approved Jemena Gas Networks terms and conditions as opposed to the detailed clause in Multinet and AusNet terms and conditions, which we proposed in the first draft of the terms and conditions.
Final Plan Outcome	
We have continued standardising our terms and conditions for our networks across Australia. Our AA Document will remain consistent with the AA Document that applies in the current AA period.	

14.3 Terms and conditions review

14.3.1 Approach

We commenced a process of standardising our terms across all jurisdictions where we have networks in 2012.

We believe there are a number of benefits to our customers from standardising terms of access, including promoting greater efficiency across the industry and reducing transaction costs.

Our approach to developing the proposed terms and conditions includes:

- harmonising the proposed terms with those for our Victorian and Albury networks, taking into consideration any jurisdictional differences requiring variation (being the most recent network terms approved by the AER);
- incorporating common amendments recently included in our South Australian Haulage Agreements which will improve alignment and efficiency in our terms and conditions across Australia;
- correcting typographical errors and anomalies;
- correcting references to matters that are no longer relevant (e.g. due to the passage of time and changes to legislation and standards);
- incorporating feedback from our RRG on the three drafts of our proposed terms and conditions; and
- incorporating feedback received during the Draft Plan consultation on the proposed terms and conditions.

14.3.2 Key changes

Each change and the basis for it are set out in detail in Attachment 14.1. Key changes include:

- amendments to align with the Australian Energy Market Operator (AEMO) Retail Market Procedure (RMP) for "current user" and "user or current user";
- amendments to align with the RMP, specifically that a "…network operator must use reasonable endeavours to read meters in accordance with the applicable meter reading schedule…";
- amendments as requested by a member of the RRG to address where Users are procuring their gas through a market mechanism (eg Short Term Trading Market) the User may not have a relationship with any shipper or the affected shipper, nor can the User make requirements on that shipper;
- insertion of a clause to enable the requesting of customer details from retailers for the purpose of operating, maintaining or management of the Network or the provision of Distribution Services. We consider it beneficial for customers if we have this information, as it will enable us to contact customers in a timely manner by multiple methods. At present, we can generally only conduct letterbox drops or mail outs to "the householder". It will also support the introduction of digital communication channels in a cost effective way, which was a key insight from our customer workshop as detailed in Table 5.10;
- insertions of clauses to disclose confidential information to a related body corporate and disclosure of information to associated companies; and
- insertion of receipt points.

The above is not an exhaustive list and the detailed explanations in Attachment 14.1 should be considered in reviewing our Final Plan. Attachment 14.3 contains a marked version of the proposed terms and conditions.

14.4 Summary of the AA Document

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 AA Document.

We are proposing the following changes to the AA Document:

- Network Extensions and Expansions, Capacity Trading, Queuing and Changing Receipt and Delivery Points – changes to align with recent changes to the NGR;
- Speculative Capital Expenditure – addition of clause to align with our Victorian and Albury AA Document;
- Capital Expenditure Sharing Scheme – addition of clause and Annexure to detail the application of the scheme;
- revised maps and heating value table;
- Return on Debt Formula - adopted changes from the AER in its recent decision on the Rate of Return Instrument; and

- making consequential definitional changes and corrections.

Attachment 14.2 provides a summary of the changes to the AA Document and a marked version of the AA Document.

14.5 Summary

The terms and conditions are a key part of our relationship with network users. The proposed terms form the basis on which users gain access to our networks and generally form the basis for the contractual agreements entered into between AGN and retailers. Our proposed terms have gone through considerable consultation with stakeholders over the past seven years.

We consider that the process of standardising our terms across our networks is consistent with achieving lowest sustainable costs for our customers.

Glossary			
AA	Access Arrangement	HRS	Haulage Reference Service(s)
ACQ	Annual Contract Quantities	HSE	Health Safety Environment
AER	Australian Energy Regulator	HyP SA	Hydrogen Park South Australia
AGIG	Australian Gas Infrastructure Group	I&C	Industrial and Commercial (customers)
AGN	Australian Gas Networks	ILI	In Line Inspection
AHC	Australian Hydrogen Centre	KPI	Key Performance Indicator
AMS	Asset Management Strategy	LPG	Liquid Petroleum Gas
ARENA	Australian Renewable Energy Agency	MDQ	Maximum Daily Quantity
ARS	Ancillary Reference Service	MFP	Multifactor Productivity
CALD	Culturally and Linguistically Diverse	MGN	Multinet Gas Networks
capex	Capital Expenditure	MRP	Market Risk Premium
CBD	Central Business District	next AA period	2021/22 to 2025/26
CCP, CCP24	Consumer Challenge Panel, Consumer Challenge Panel 24	NGL	National Gas Law
CESS	Capital Expenditure Sharing Scheme	NGR	National Gas Rules
COTA	Council for the Ageing	opex	Operating Expenditure
CSIRO	Commonwealth Scientific and Industrial Research Organisation	OTR	Office of the Technical Regulator
current AA period	2016/17 to 2020/21	PMC	Periodic Meter Change
DBP	Dampier Bunbury Pipeline	RBA	Reserve Bank of Australia
DCVG	Direct Current Voltage Gradient	RRG	Retailer Reference Group
DP	Delivery Point	SAMP	Strategic Asset Management Plan
DMSIP	Distribution Mains and Service Integrity Plan	SARG	South Australian Reference Group
DRP	Debt Risk Premium	SAFRRA	South Australian Federation of Residents and Ratepayers Associations
EBSS	Efficiency Benefit Sharing Scheme	SCADA	Supervisory Control and Data Acquisition
EDD	Effective Degree Day	Subsequent AA period	2026/27 – 2030/31
ESCOSA	Essential Services Commission of South Australia	TAB	Tax Asset Base
EWOSA	Energy and Water Ombudsman of South Australia	TJ	Terajoule/s
FFO	Funds from operations	TRIFR	Total Recordable Injury Frequency Rate (the number of total recordable injuries per million hours worked)
GJ	Gigajoule/s	TFP	Total Factor Productivity
GSP	Gross State Product	UAFG	Unaccounted for Gas
HDPE	High-Density Polyethylene	VCAP	Vulnerable Customer Assistance Program
HIA	Housing Industry Association	WPI	Wage Price Index

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