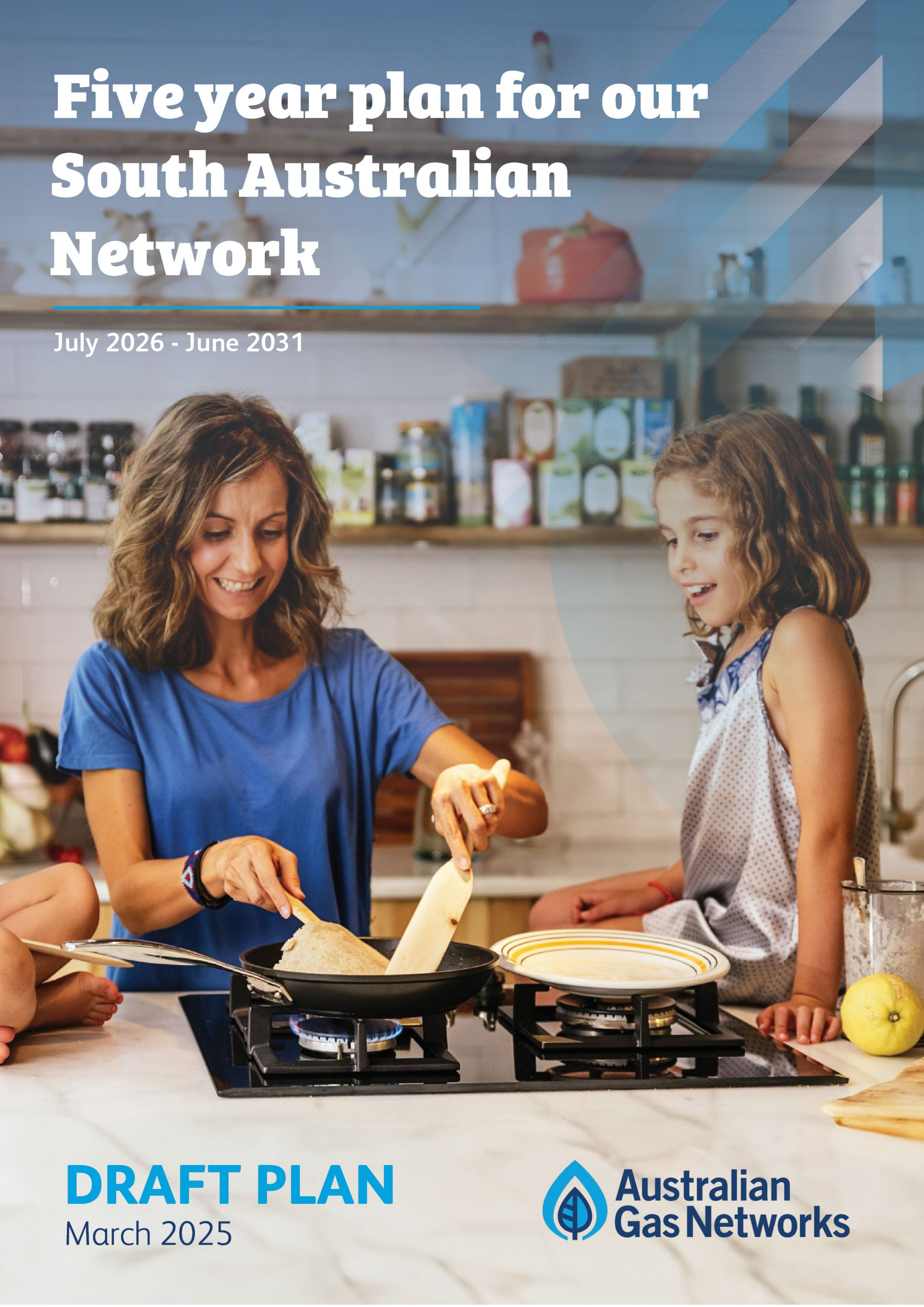
Five year plan for our South Australian Network

July 2026 - June 2031



DRAFT PLAN

March 2025

Australian Gas Networks

Contents

We are Australian Gas Networks. We deliver gas to more than 485,000 homes and businesses in South Australia every year. We do this safely, reliably and in a cost-efficient manner for our customers.

Our vision is to provide infrastructure that is essential to a sustainable energy future. We are actively participating in the energy transition by delivering the natural gas needed today and advancing solutions for tomorrow.

Since 2021, our Hydrogen Park South Australia facility has been delivering blended renewable hydrogen to hundreds, then thousands, of homes. This facility demonstrates the safe delivery of renewable gas – and now we're planning for the next step in delivering renewable gas through HyP Adelaide.

These projects will continue to lay the foundation to ensure our customers will enjoy gas cooking and heating in their homes and businesses into the future.

CEO Foreword

Our Draft Plan for the South Australian distribution network prioritises stability as the energy transition continues. Our efficient and effective operations mean we can offer steady prices for our customers over the next five-year period, while continuing to deliver a sustainable future for the network and our customers.

This Draft Plan for the South Australian distribution network outlines how we will continue to deliver safe and reliable services to our customers during a period of ongoing change in the energy sector.

At Australian Gas Infrastructure Group (AGIG) we deliver infrastructure for a sustainable future. Our AGN South Australian distribution network plays a crucial role in the economy and community more broadly by serving the energy needs of households, businesses and industry in Adelaide and the regions.

Customers are at the centre of our plans. This means ensuring we deliver for our customers now and into the future. Our Draft Plan seeks to outline what we have delivered for our customers in the current AA period (July 2021 to June 26) and what we will deliver in the next AA period (July 2026 to June 31).

Performance in the current AA

In the current AA period, we have delivered on our goal of maintaining a customer focus. In 2024 we achieved:

a customer satisfaction rating of 8.7, maintaining excellence throughout the current Access Arrangement; and

some of the lowest incident rates across AGN for both our Total Recordable Injury Frequency Rate (TRIFR) (which decreased from 8.3 in 2021 to 2.0) and Lost Time Injury Frequency Rate (LTIFR) (which decreased from 0.9 to 0).

We will also have concluded our low-pressure mains replacement program by the end of the current AA period. Over the last two decades we have replaced around 2,000 km of low-pressure mains. This is an important achievement that improves safety, reduces greenhouse gas emissions and, looking ahead, ensures our infrastructure is ready for renewable and carbon neutral gases.

In the current period we also introduced our Priority Services Program for customers who are experiencing vulnerability at a time when they need us the most. With Priority Services, customers have access to a dedicated customer care team, providing access to additional support and services when needed. The program commenced in July 2023 and has helped over 100 customers experiencing vulnerability in SA so far, and will be continued in the next AA period.

These outcomes demonstrate our commitment to the safety, reliability and service expectations of our customers. A commitment we intend to maintain in the next AA period.

Customer and stakeholder engagement

Our Draft Plan follows nearly 12 months of engagement with our customers and stakeholders.

In strengthening our program of engagement activities, and to promote breadth and depth of engagement, we have partnered with Orbviz to design a digital and interactive version of the Draft Plan.

The tool presents the Draft Plan information in an engaging and interactive way. It allows customers and stakeholders to focus on the aspects of the Draft Plan that are of interest and provide feedback quickly if they wish to do so.

We intend to use the tool at our next round of customer workshops to gain insights and feedback on the Draft Plan, to help inform our Final Plan.

Four key themes have emerged from our engagement so far:

cost, affordability and price remain the key issues for most of our customers;

customers want to ensure expenditure and investment remain at levels necessary to maintain the safety and reliability of the network;

customers expect us to sustain the current level of excellent customer service; and

the future of gas is important and customers are interested to understand more about renewable and carbon-neutral gas, and how the network can contribute to reducing emissions.

Plans for the next AA

Our Draft Plan delivers on the themes emerging from our engagement process. Most importantly, prices will remain steady from 1 July 2026 with a marginal decrease of 0.9% (after inflation).

Recent inflationary conditions within the South Australian economy, and Australia more broadly, has resulted in an uplift in expenditure incurred in the later years of the current AA period. These higher costs are expected to continue into the next AA period.

That said, we are pleased that our forecast of capital expenditure is expected to decrease by 9% in the next AA period, reflecting the conclusion of the low-pressure mains replacement program by the end of this period. Operating expenditure is however expected to increase by 33%, reflecting proposed changes to the capitalisation approach for some activities and the increased gas cost to meet our unaccounted for gas (UAFG) obligations. Overall, total expenditure is expected to increase by $67 million, or 7.3%.

Future of Gas

South Australia is at the forefront of the energy transition and our network continues to play a key role in delivering sustainable energy choices.

The current policy environment in the state respects customer choice and the role gas can play in a sustainable future as South Australia leads the country in renewable and carbon neutral gases.

In the current AA period, Hydrogen Park South Australia (HyP SA) has successfully expanded. After initially providing (by volume) a 5% blend of renewable hydrogen to around 700 homes, the project was expanded to provide a 10% blend to around 5,000 homes and businesses. HyP SA has laid the foundation for larger scale hydrogen production and future potential uses.

The next step is to expand delivery to the whole of the Adelaide distribution network with Hydrogen Park Adelaide (HyP Adelaide). HyP Adelaide incorporates a 60 MW electrolyser providing a 10% blend by volume of renewable hydrogen to the majority of the Adelaide network. Further work on the project is progressing, including the potential form of jurisdictional support for the project. For this Draft Plan, we have included $26 million to be recovered through operating expenditure. This project will continue South Australia's leadership position in the energy transition and provide customers with sustainable energy choices into the future.

Demand and Price

While we consider our networks will continue to play a role in the future energy mix, we recognise we face a more competitive environment now and into the future. Demand per residential connection has declined by more than 15% over the current AA period as our customers invest in energy efficiency and change the way they use energy.

As behaviour and technology continue to change, we need to fine-tune the way we calculate our tariffs to enable a smooth transition to net zero emissions. Consistent with recent decisions by the Australian Energy Regulator, we are reviewing the structure of our tariffs and how our tariffs vary each year within the AA period.

In developing this Draft 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.

Publishing the Draft Plan helps to ensure that customers remain at the centre of our planning.

I strongly encourage our customers and stakeholders to provide feedback and seek out our engagement activities across South Australia. With your feedback, we can develop and provide a Final Plan to the Australian Energy Regulator in July 2025 reflective of customer and stakeholder needs now and into the future.

Craig de Laine

Chief Executive Officer

Draft Plan

2026/27 – 2030/31

Australian Gas Networks

Delivering a sustainable future for our South Australian customers

Our customers and stakeholders value:

- Keeping prices stable
- Maintaining a high level of safety and reliability
- Continuing our strong track record of customer service
- Investing for a sustainable future

Stable prices

↓0.9%

(after inflation)

Our plan from July 2026:

Customer Focussed

31,000 new connections

>82% customer experience performance score

A Leading Employer

Target Zero Harm across our operations

>80% health and safety performance score

Operational Excellence

Public leak reports within 2 hours **>98.5%**

Continued replacement of multi-user services

Sustainable Communities

Continue to deliver the Priority Services Program

Connect renewable gas projects to our network

1 Plan highlights

Our Draft Plan outlines the activities and investments we propose to undertake for the 2026/27 to 2030/31 period and the resulting price change for our customers.

IN THIS CHAPTER:

- **An upfront price cut for the next period of nearly 1% builds on price cuts of 7% and 21% delivered at the beginning of the prior and current AA periods.**
- **We have a strong track record of safety, reliability and customer service in the current period.**

Customers are at the centre of our plans. Our Draft Plan has been informed by our customer and stakeholder engagement program, which commenced nearly 12 months ago.

This chapter summarises how we have developed our Draft Plan, our achievements for the current AA period and the key elements of our proposal for the next period, 2026/27 to 2030/31.

1.1 Developing this plan

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

We held a total of 16 dedicated customer workshops (12 face-to-face and 4 online), with 213 participants in 6 locations. We engaged with a diverse set of customers, including dedicated workshops with the Culturally and Linguistically Diverse (CALD) community, and stakeholders to inform our Draft Plan.

This Draft Plan has been informed by the feedback we received in stages one and two of our engagement program. This feedback combined with further engagement activities will help us further refine our Final Plan for submission to the AER by 1 July 2025.

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 deliver infrastructure essential to a sustainable energy future. In delivering our vision we will be customer focussed – that is continue to deliver quality services that our customers value. Our vision is also supported by being recognised as a leading employer, delivering operational excellence and contributing to sustainable communities. During the current period we have delivered on that vision, and we aim to continue our progress during the 2026/27 to 2030/31 period.

Our key achievements during the 2021/22 to 2025/26 period so far are summarised below.

Customer focussed

- Our customer satisfaction score for AGN SA has been consistently excellent, with a score of 8.7 in 2024.
- We will have connected over 31,000 customers by the end of this period, bringing our total customer base to around 491,000.
- 87% of emergency calls have been answered within 30 seconds.
- Our South Australian Priority Services Program (PSP) was launched in July 2023 with around 100 registrations so far.

A leading employer

- In the current period, the Total Recordable Injury Frequency Rate (TRIFR) has averaged 5.4, the lowest rate achieved in AGN's history. This is a very significant improvement from a score of more than 10 reported in our last Draft Plan for AGN South Australia.
- We offer our employees up to 2 days volunteer leave each year. In 2024, our employees volunteered over 400 hours to contribute to the communities we serve, which is our highest every contribution.
- We are recognised as an Inclusive Employer by the Diversity Council of Australia 2023-24
- As at December 2024, our workforce is evenly balanced from a gender perspective.
- In 2024, we placed 12th in the GoodCompany's "Best Workplaces to Give Back" – up from 16th place in 2023.
- 100% of compliance training has been completed within the required timeframes.

Operational excellence

- Delivered an upfront price cut of 7% (after inflation) on 1 July 2021
- Capex is projected to be 13% lower than the benchmark, reflecting the efficient delivery of our mains replacement program and our commitment to continuous improvement.
- We will have removed all the cast iron and unprotected steel and other identified highest risk low and medium pressure mains, representing a significant milestone in enhancing network safety and reliability.
- We will complete inline camera inspections and reinforcements on HDPE 575 and DN50 mains. This will extend the service life of these mains for an estimated additional ten years.
- We are forecast to outperform our opex allowance by 22% in this AA period, even with cost pressures evident towards the end of the period.

Sustainable communities

- In 2021 we connected Australia's largest renewable hydrogen production facility, Hydrogen Park South Australia (HyP SA), to the network providing a renewable hydrogen blend of up to 5% by volume to around 700 homes.
- In 2023 and 2024 we expanded HyP SA such that it now delivers a hydrogen blend up to 10% by volume to around 5,000 homes, businesses and schools.
- At the end of 2024, AGIG achieved ~40% scope 1 emissions reduction relative to 2005 levels, on a pathway to meeting the Federal Government Target of 43% reduction by 2030.
- Our overall Risk Management Strategy and ESG Governance ensure we can continue to deliver services without interruption, and strong cyber security is an integral part of this.
- In 2023, AGIG enhanced its cyber security risk management governance as part of our Critical Infrastructure Risk Management Program, which the Board is ultimately accountable for maintaining.
- Our Reflect Reconciliation Action Plan (RAP) was launched in September 2023.

1.3 What we will deliver

Our Draft Plan for the 2026/27 to 2030/31 period builds on our strong performance over the current period. We acknowledge the longer term challenges the gas distribution industry faces, which matters have been addressed by our plans.

We are committed to meeting our obligations and customer expectations over the next AA period. The activities and expenditure we propose to undertake in the next five years are summarised below.

Customer focussed

- We will connect around 31,000 new residential, business and industrial customers by the end of the next AA period.
- We will augment our network at the northern and southern boundaries to safeguard service levels for both existing and new customers.
- We will systematically replace ageing meters to maintain accurate customer billing. Additionally, we will install digital meters at inaccessible sites and offer customers the opportunity to opt in for a digital meter, providing greater control and transparency over their bills.
- We will improve our website and digital platform and implement analytics and functionality to optimise our customers' digital experience.
- We have proposed a price path that provides an upfront price cut for customers, which has the ancillary benefit of

minimising price volatility in the next 5-year period.

- We have sought to implement the AER's preferences for amendments to our tariff structure (for flatter tariffs) and form of revenue control (to implement a control element to the weighted average price cap when there is material revenue variation from forecast) in a manner that maintains price stability for our customers.

A leading employer

- We will continue to target zero harm throughout our operations.
- In 2024 we launched our Diversity, Equity and Inclusion (DEI) Engagement Plan for the 2024 to 2026 period and achieved a key target under the United Nations Sustainable Development Goal (SDG) 8 – Decent Work and Economic Growth.
- We will continue to invest in our employee experience and the skills of our people.

Operational Excellence

- We will continue our current program to replace Multi-User Services (MUS) sites, following the completion of 457 of the highest risk (Priority 1) MUS sites in the current AA period.
- We will optimise our IT environment through continued consolidation and integration under the AGIG One IT Strategy, achieving economies of scale in IT procurement, support and operational planning.
- We will focus on critical asset integrity and risk mitigation initiatives, including the dig-up and modifications to our high- pressure transmission mains to enable Inline Inspection (ILI), and implementing measures to minimise overpressure risks at District Regulating Station (DRS).
- We will maintain our very high reliability performance, where our customers experience one hour off-supply every 40 years, on average.

Sustainable communities

- We currently plan on connecting our network to HyP Adelaide, a 60MW electrolyser due for completion during the next AA period. We will engage further on these plans with our stakeholders, including the South Australian Government, prior to the submission of the Final Plan.
- We will further reduce our emissions through targeted protected steel mains replacement, lowering unaccounted-for-gas (UAFG) on the network. We have already achieved a significant reduction in UAFG through the completion of the next stage of our low-pressure mains replacement program in the current period.
- We will continue to grow the Priority Services Program to help those customers experiencing vulnerability.

Overall, our Draft Plan delivers steady prices with an upfront price decrease of 0.9% (after inflation). Importantly, in before inflation (or "real" terms), the prices our customers are forecast to pay for our gas transportation services at the end of the next AA period will be lower than at the end of the current period, and lower than they were 10-years ago.

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.

In 2023, Energy Ministers agreed to change the national energy laws to include an emissions reduction objective into the NGR, including amendments to the new capital expenditure criteria. The amendments allow the AER to approve capex where it contributes to meeting a jurisdiction's emissions reduction targets through the supply of services. We consider that if South Australia's emissions reduction targets are to be achieved, it will require a whole of system approach. We are keen to contribute to the achievement of these targets in the next AA period.

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.

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 Draft Plan seeks feedback on our proposals for the South Australian distribution network for the five-year period commencing 1 July 2026. It will inform our Final Plan, which we are required to submit to the AER by 1 July 2025.

The Draft Plan provides our preliminary views on the activities and expenditure we propose to undertake in the next AA period (from 1 July 2026 to 30 June 2031). It includes feedback received to date from our customers and stakeholders

After the opportunity to comment on the Draft Plan, our customers and stakeholders will also have further opportunity to engage as we develop our Final Plan. The AER will also engage with stakeholders through its own process.

How to read this plan

The first five chapters of this document provide an overview of our plans, our business, our stakeholders, our track record and the process we have undertaken to develop a plan that reflects our vision.

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

- Financing costs – the cost of financing our capital base and meeting our tax obligations (Chapter 11);
- Operating expenditure – the expenditure we require to run our business day-to-day (Chapter 8);
- Capital expenditure – the investment in our assets required to deliver services to our customers (Chapter 9);
- Regulatory Depreciation – consistent with the requirements of the NGR, the appropriate depreciation schedule for the next AA period, taking into consideration the impact of the energy transition on our business over time, (Chapter 6);
- Pipeline and Reference services – the Reference Services we propose to offer in the next AA period, including consideration of the AER's Final Decision (published December 2024) on our Reference Service Proposal (Chapter 7);
- Capital base – the total value of our investment in the South Australian network (Chapter 10);
- Demand forecasts – the total amount of services we forecast our customers will demand over the period (Chapter 12); and
- 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 13).

In the last two chapters, we outline how we have calculated the total revenue required, the resulting prices for our services (Chapter 14), and the terms and conditions for access (Chapter 15).

All numbers quoted throughout this Final Plan are $2025/26, unless otherwise labelled.

Next steps

We encourage our customers and stakeholders to provide feedback on this Draft Plan. Your feedback is a key part in achieving our objective of submitting a Final Plan that is capable of being accepted by our customers and stakeholders.

At the end of each chapter, we have highlighted key questions on which we are seeking your feedback. A full list of the questions is also provided at the end of this document.

Contact information is provided on the back cover of this document. We are seeking your feedback by 28 April either online at gasmatters.agig.com.au or by mail or in person.


Multinet Gas Networks
Gas Meter
POSITION
GAS PRESSURE
Freestanding Meter Installation
Australian Gas Networks

2 Our business

We deliver gas safely and reliably to more than 485,000 South Australian homes and businesses every year.

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.**

Australian Gas Networks (AGN) is part of the Australia Gas Infrastructure Group (AGIG).

2.1 About AGIG

AGIG serves over two million customers across every mainland state and the Northern Territory. Our assets include around 36,000 km of distribution networks, 4,300 km of transmission pipelines and 60 petajoules of storage capacity.

2.2 Our vision

At AGIG, our vision is to deliver infrastructure that is essential to a sustainable energy future. It is made up of four strategic pillars:

- *Customer focussed* – this means ensuring public safety and the provision of high levels of reliability and excellent customer service.
- *A leading employer* – this means ensuring the health and safety of our employees and contractors, and having an engaged and skilled workforce through leading employment practices.
- *Operational excellence* – this means getting the work done within benchmark by continually looking for ways to lower the cost of our services while delivering continuous improvement and the very high levels of reliability that our customers value.
- *Sustainable communities* – this means a commitment to long-term positive impacts on the environment and that our operations contribute to the wellbeing and resilience of the communities we serve.

The activities and investments in this Final Plan are designed to achieve these strategic pillars, and our Vision. The chapters that follow will discuss our plans in the context of these objectives alongside the requirements of the NGL and NGR.

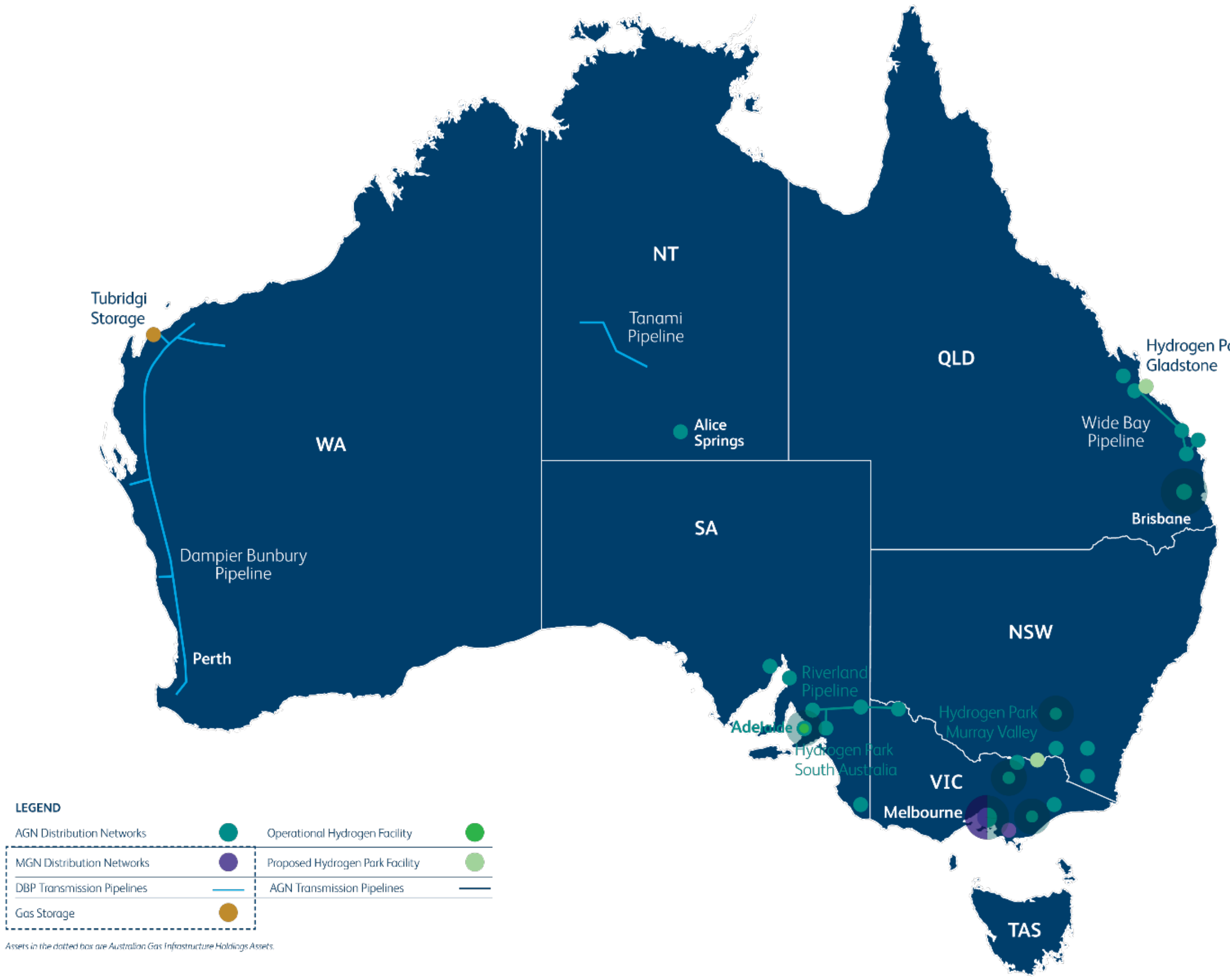
We also publicly report under our Vision, most recently in our 2024 Environmental, Social and Governance Report.

2.3 Our values

To achieve our vision, we embrace four values in everything we do:

- we build trust;
- we are accountable;
- we care; and
- we are one team.

Figure 2.1: AGIG's operations across Australia



2.4 Delivering for customers first

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

This commitment reflects our ongoing practice of engaging with customers and stakeholders, including publication of a Draft Plan prior to formal lodgement of our Final Plans with regulators. In developing this Draft Plan, we have engaged with our customers through a number of 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.

Our Role in the Gas Supply Chain

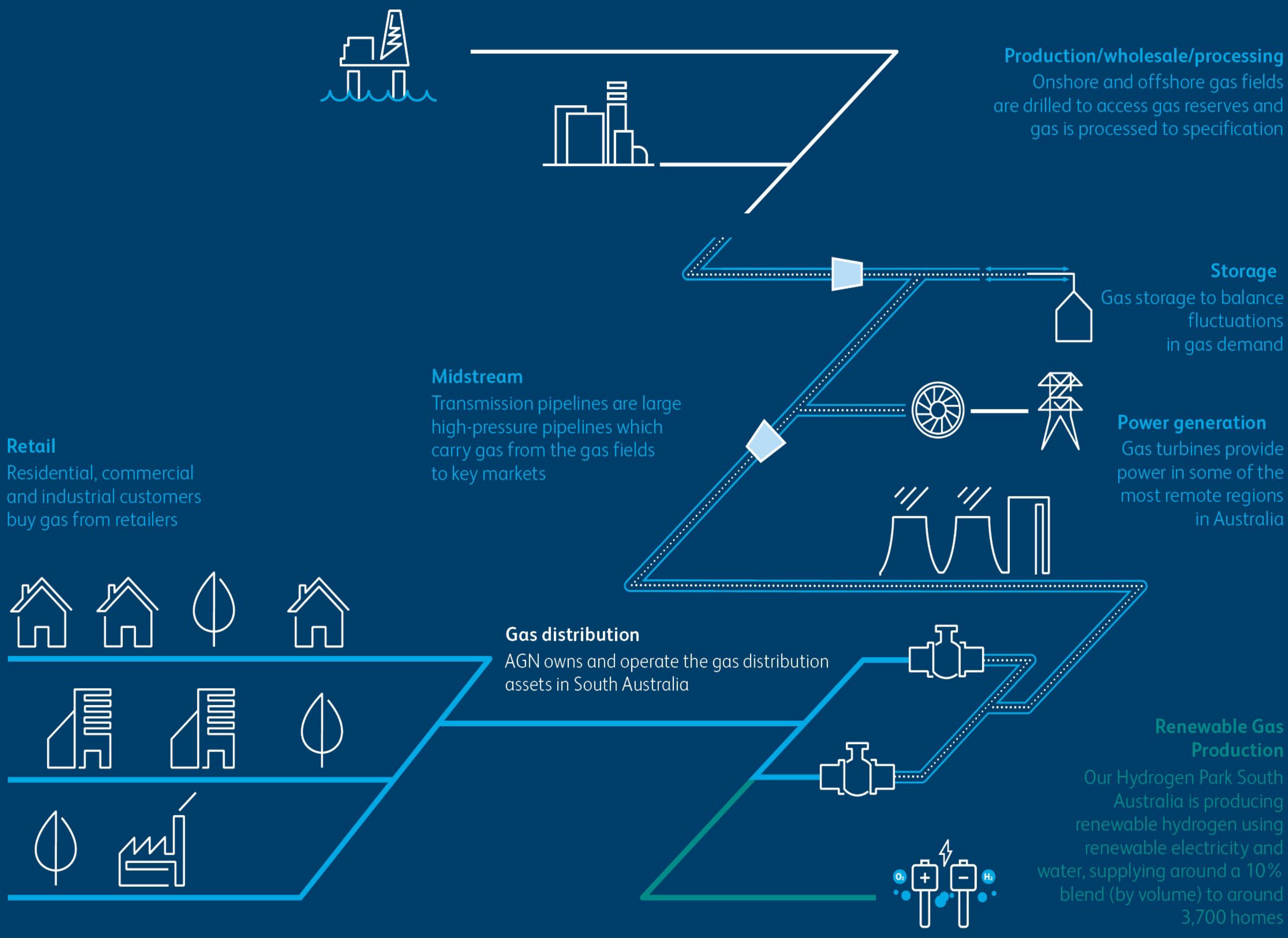
We own and operate the gas distribution infrastructure that delivers gas across South Australia.

We don't own gas, we transport it. We service the needs of Producers, major energy users and residential and business users by transporting gas from those who produce it to those who use it.

Our customers choose their gas retailer, who purchase the gas on the customers' behalf. The gas is transported through transmission pipelines and our distribution networks to customers' premises. Retailers pay network charges to the transmission and distribution network businesses and recover these costs from customers through their retail gas bills.

Our customers might interact with us on the following occasions:

- to obtain a new gas connection
- if they experience an outage that is either planned or unplanned
- to report a gas leak
- if they are experiencing an issue with their meter or when their meter is being read
- upgrades or maintenance are occurring in their street or community
- they have a general enquiry or complaint about their gas supply or service.



Our Vision

To deliver infrastructure essential to a sustainable energy future

Our Strategic Pillars

Customer Focussed

Public Safety

Customer Experience

Cost Efficient

A Leading Employer

Health and Safety

Employee Experience

Skills Development

Operational Excellence

Profitable Growth

Benchmark Performance

Reliability

Sustainable Communities

Enabling Net Zero

Environmentally Focussed

Socially Responsible

Our Values

We build **Trust**

We are **Accountable**

We **Care**

We are **One Team**

2.5 Zero Harm

Maintaining the safety of our workforce and the public is always the central focus of all our activities. When developing our Final Plan and the work programs that underpin it, our aim is to do everything we can to meet the obligations of our safety case and asset management strategies.

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. We have made good progress in the current AA period, where injury rates are the lowest they have every been.

Our safety focus was also recognised by the Australian Gas and Pipelines Association, where we received the 2024 Safety Excellence award in recognition of our underground asset location work.

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 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. Our gas transmission assets also provide a key role in electricity generation in Western Australia. 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 by our South Australian distribution network.

2.7 Our role in South Australia

Natural gas plays a pivotal role in South Australia, providing a reliable source of energy for homes, businesses and 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.

AGIG is also at the forefront t 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 delivery net zero, by developing and implementing a pathway to zero emissions for our South Australian distribution network. More information on HyP Adelaide is available in Chapter 4.

Figure 2.3: SA gas network

3 Our track record

In the 2021 to 2026 period we have continued to deliver the strong safety, reliability and service standards expected by our customers.

IN THIS CHAPTER:

- **We are close to concluding our low pressure mains replacement program with the replacement of 704km of low pressure mains over the period, improving safety, reducing greenhouse gas emissions and delivering infrastructure ready for renewable and carbon neutral gases in the future.**
- **We have connected and expanded Hydrogen Park South Australia, which now delivers a 10% renewable hydrogen blend to more than 5,000 customers on our SA distribution network.**

During the current AA period our focus has been on safety, customer service, minimising costs and completing our mains replacement program.

Our activities have been guided by our vision, to deliver infrastructure for a sustainable energy future. Our activities in the current period contribute to the four pillars of our vision: customer focussed, a leading employer, operational excellence and sustainable communities.

3.1 Customer focussed

Customer focussed means ensuring public safety and the provision of high levels of reliability and customer service in a cost efficient way.

Under this pillar our targets have included responding and repairing leaks within set timeframes, customer satisfaction delivering connections and our mains replacement program.

In the current period to date, we have delivered against these targets by:

- Strong public safety performance – responding to 99% of publicly reported leaks within 2 hours;
- Very high reliability – our customers experience one hour off supply every 40 years, on average;
- 91% of emergency calls were answered within 10 seconds in 2024; and
- customer satisfaction scores have been consistently high, with a score of 8.7/10 in 2024.

3.2 A leading employer

Being *a leading employer* means ensuring the health and safety of our employees and contractors, and having an engaged and skilled workforce.

In this pillar our targets have included HSE and employee engagement performance.

In the current period to date, we have delivered against these targets by:

- Achieving very significant improvements in our Total Recordable Injury Frequency Rate (TRIFR), which has averaged 5.4 in the current period. This is a very significant improvement from a score of more than 10 reported in our last Draft Plan for AGN South Australia. Injury rates are currently the lowest they have been in our history;

- We continue with our health and safety initiatives, including annual zero harm workshops, a HSE culture model and reporting and HSE recognition awards; and
- 100% of compliance training has been completed within the required timeframes.

3.3 Operational excellence

Operational excellence means getting the work done within benchmark levels by continually looking for ways to improve cost of service through efficiency, quality and continuous improvement.

In the current period to date, we have delivered against these targets by way of the following:

- Delivering a price cut of 7% to our customers on 1 July 2021;
- Completing our low-pressure mains replacement program by the end of current AA period. This is the conclusion of a multi-decade program replacing more than 3,000km of low-pressure pipelines. This safety driven program has the added benefit of making the network ready for 100% renewable gases;
- Responding to 98% of public leak reports within 2 hours;
- Capex is expected to be 13% below allowance, reflecting our efficient delivery of the mains replacement program and focus on continuous improvement; and
- Opex is expected to be 22% below our allowance, reflecting lower unaccounted for gas (UAFG) following our low pressure mains replacement program and general operational efficiency ahead of emerging cost pressures at the end of the period.

3.4 Sustainable communities

Sustainable communities means ensuring we are environmentally and socially responsible in the way we provide services.

Under this pillar our targets have included taking first steps to develop options for the long- term future of the South Australian distribution network.

In the current period to date, we have delivered against these targets by:

- capturing ESG information from 2024 as part of our procurement processes for major projects;
- delivering our Priority Services Program in 2023, which has supported around 100 SA customers experiencing vulnerability;
- completing our low-pressure mains replacement program which has driven UAFG to record low levels; and
- connecting and expanding Hyp SA, which now delivers an up to 10% renewable hydrogen blend to more than 4,000 customers on our SA distribution network.

4 What we will deliver

This Draft Plan supports our vision to deliver infrastructure for a sustainable future in the 2026–2031 period.

IN THIS CHAPTER:

- **We will deliver stable prices into the next AA period for customers recognising the current cost of living pressures being experienced by the community.**
- **We will connect around 31,000 customers to the network in the next AA period.**

Our Draft Plan sets out how we will continue to provide affordable, safe, reliable and sustainable gas distribution services today and for the future in South Australia.

Our activities for the next AA period will be guided by our vision, to deliver infrastructure for a sustainable future. Our activities will contribute to the four pillars of our vision: customer focussed, a leading employer, operational excellence and sustainable communities.

4.1 Customer focussed

Customer focussed means ensuring public safety and the provision of high levels of reliability and customer service.

In the next AA period we will deliver on this pillar 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 experience scores at or above 81%;
- connecting around 31,000 new residential, business and industrial customers.
- proceeding with the medium risk Multi-user Services (MUS) renewal following the completion of highest risk MUS in the current AA period;
- ensuring accurate billing through systematically renewing ageing meters and introducing digital meters in hard-to access locations, while also giving customers the option to switch to digital meters for better bill management.
- enhancing digital customer services by upgrading our website with online tools and analytics to offer bill saving estimates and cost-effective online repair solutions.

4.2 A leading employer

Being *a leading employer* means ensuring the health and safety of our employees and contractors and having an engaged and skilled workforce.

In the next AA period we will deliver on this pillar by:

- continuing to target zero harm through workshops and re-enforcing our HSE culture;
- switching from lagging indicators to leading indicators of employee safety; and

- continuing our health and safety initiatives, including our various wellbeing initiatives.

4.3 Operational excellence

Operational excellence means getting the work done within benchmark levels by continually looking for ways to improve cost of service, pursue growth and maintain very high levels of reliability.

In the next AA period, we will deliver on this pillar by:

- Delivering an upfront price cut of 0.9% (after inflation) on 1 July 2026, which builds on our price cuts delivered in prior AA periods of 7% and 21%;
- Continuing to target our long-standing reliability of the network with limited disruption to our customers;
- Connecting around 31,000 new customers and 228 km of new mains length into the network; and
- Incorporating a productivity adjustment into our operating expenditure forecast.

4.4 Sustainable communities

Sustainable communities means ensuring we are environmentally and socially responsible in the way we provide services.

In the next AA period we will deliver on this pillar by:

- Continuing to support customers experiencing vulnerability through our Priority Services Program;
- Enabling renewable gas opportunities such as HyP Adelaide (see Box 4.1) to bring renewable gases into the network; and
- Replacing protected steel sections of the network to continue to reduce UAFG.

Question for consideration

1. Do you have any views on what we plan to deliver for the next AA period?

Box 4.1: Hydrogen Park Adelaide

About Hydrogen Park Adelaide

Hydrogen Park South Australia (HyP SA), located in the Tonsley Innovation District, has been successfully delivered in the current AA period, demonstrating our ability to safely deliver renewable hydrogen to around 4,000 customers through the existing gas distribution system.

We are working on the next step in decarbonising South Australian gas supply, which includes the potential for Hydrogen Park Adelaide (HyP Adelaide).

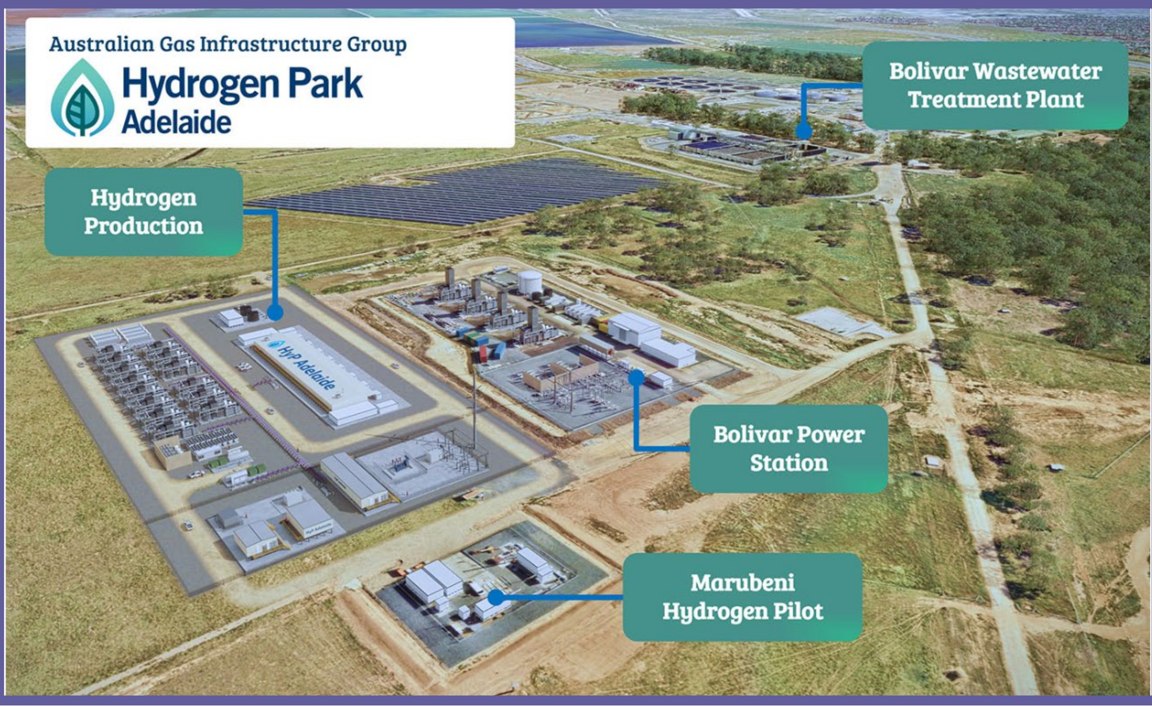
HyP Adelaide is a proposed 60 MW renewable hydrogen production facility located at SA Water's Bolivar wastewater treatment plant, that will aim to produce up to 900 TJ per year of renewable hydrogen. HyP Adelaide is proposed to be Australian Gas Infrastructure Group's next key milestone, building from the capability and knowledge from HyP SA and Hydrogen Park Murray Valley.

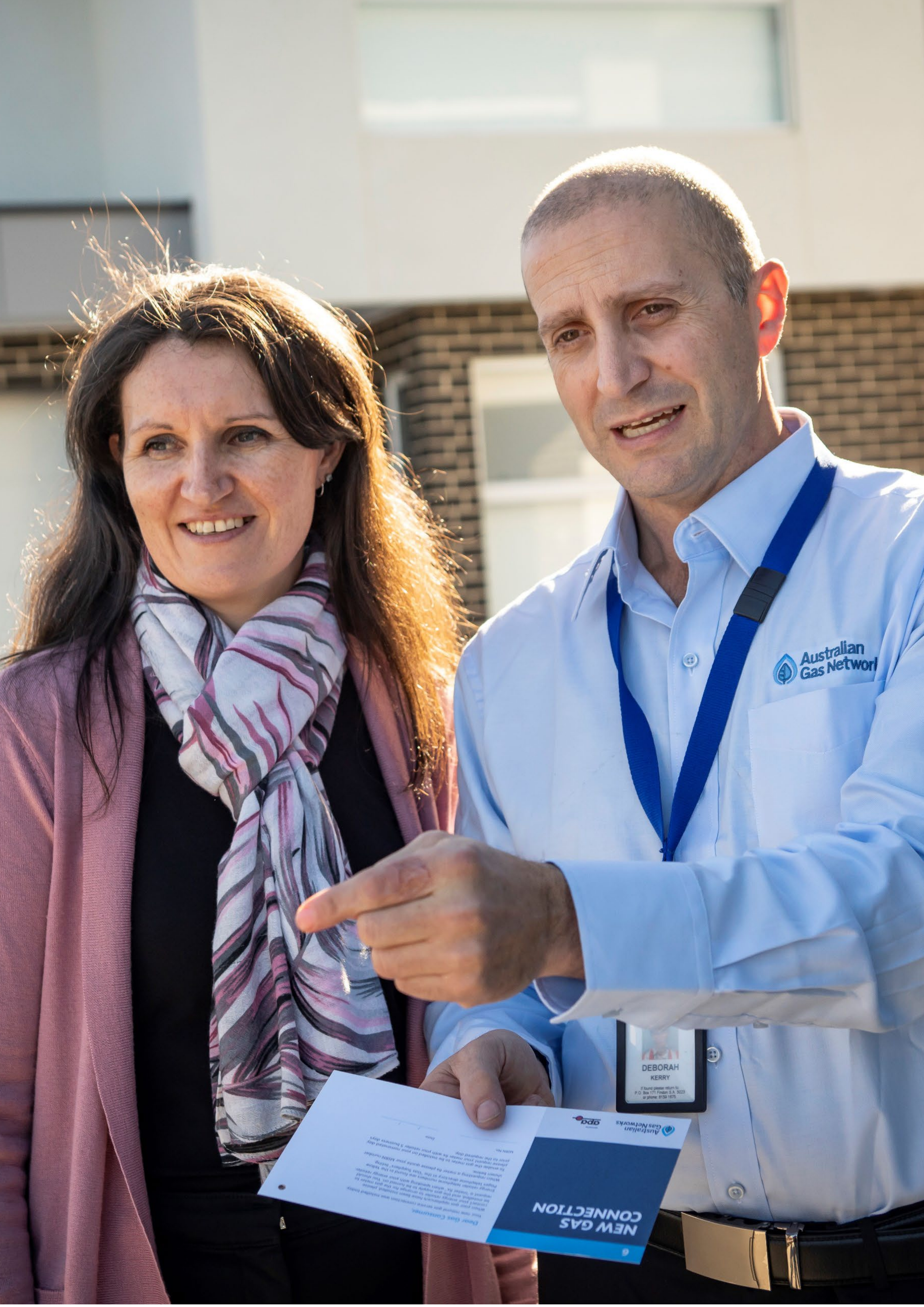
HyP Adelaide intends to deliver hydrogen to the Gepps Cross city gate via a new pipeline. The gas will then be blended at up to 20% by volume into Adelaide's gas networks, supplying over 480,000 customers.

HyP Adelaide would assist with decarbonisation of gas supply in Adelaide and enable large industrial customers to offset their gas usage by acquiring renewable gas certificates generated by reference to renewable hydrogen produced at the facility. Renewable hydrogen could also potentially be supplied to the Bolivar Power Station adjacent to the site, blended into its gas supply at up to 25% by energy. The renewable hydrogen would assist by providing a lower carbon option to help firm South Australia's electricity grid.

In addition, we are exploring other opportunities to supply oxygen and waste heat generated by the facility to industrial customers.

We are liaising with the South Australian government on policy support to help deliver the project. The impact of the policy being explored has been estimated and included in our operating expenditure forecast (see chapter 8). Importantly, network prices remain stable for our customers through the next AA period.




Australian
DEBORAH
KERRY
NEW GAS CONNECTION

5 Customer and stakeholder engagement

This Draft Plan has been developed in collaboration with feedback and insights from customers and stakeholders as part of an extensive engagement plan and ensures we put a strong customer focus at the core of this plan

IN THIS CHAPTER:

- **We engaged with our customers and stakeholders to understand how they wanted to be involved in the development of our plans.**
- **We held iterative workshops with key customer groups, including residential, business, culturally and linguistically diverse (CALD) customers, to understand their needs and preferences.**
- **We designed and delivered bespoke engagement activities around key issues of importance for different stakeholder groups.**
- **We have partnered with OrbViz to design and deliver an interactive digital engagement tool to engage on the Draft Plan to promote breadth and depth of engagement.**

Thorough and effective engagement with customers and stakeholders has ensured that our business delivers on what is most important to them.

This chapter outlines how our engagement activities have informed and shaped our proposals.

It also provides an opportunity for customers and stakeholders to provide further input into the development of our Final Plan.

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 acceptance by our customers and stakeholders. This Draft Plan is a key step in achieving our objective.

We adopted a five stage approach to our engagement program which is illustrated in Figure 5.1. We have used this framework to report the outcomes against our engagement activities.

In the development of this Draft Plan we completed Phases 1 and 2 of our engagement program.

This chapter describes our engagement with key stakeholders on the development of our engagement approach, principles, methodology and timeline before engaging on what we would propose for our business in the next AA period.

It also documents and describes the engagement activities we have undertaken and how we have responded in this Draft Plan, including:

- Meetings of the South Australian Reference Group (SARG);
- Meetings of the Retailer Reference Group (RRG);
- Two phases of customer workshops with over 150 AGN returning customers from metropolitan and regional South Australia;
- In-depth workshops with culturally and linguistically diverse (CALD) customers in Adelaide, in partnership with Multicultural Communities SA;
- A "deep dive" workshop into key topics of interest as highlighted by members of our reference groups; and
- One-on-one meetings with individual stakeholders and presentations at their workshops/meetings.

Ongoing, thoughtful and targeted engagement direct with customers across the state and our two stakeholder reference groups, the South Australian Reference Group (SARG) and Retailer Reference Group (RRG), through a series of meetings and workshops, has been critical to the success of this engagement program.

Membership of the SARG reflects the diversity of our customer base, with organisations representing residential and business customers, major gas users, customers facing vulnerability, multicultural communities, the building industry and property developers.

Prior to re-engaging with the SARG at the beginning of this regulatory review period, we considered it prudent to revisit and update the Terms of Reference to ensure that the group was able to reach the best possible outcomes for our stakeholders and customers. We also extended the representation of members to make sure that we were hearing the views of a broad a cross section of South Australians as possible.

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

This chapter also summarises the outcomes of our customer workshops; what we learnt about customer expectations, how we adapted the workshops based on participant feedback, what is important to customers and how can we continue expanding on these foundations as we progress into the next stages of our engagement program.

This chapter demonstrates our dedication to building trust with our stakeholders and customers, that we will go above and beyond to ensure they understand the information we are giving them, and that they can have a say on every topic they have told us is important to them.

Figure 5.1: Our five-stage approach to engagement

Stages 1 and 2 of Engagement Program are complete

Stage 1
Strategy and research

May – Aug 2024

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

IAP2 Spectrum
CONSULT/INVOLVE

Engagement Activities
- Meet with key stakeholders
- Publish and consult on a Draft Engagement Plan
- Expand our SA reference group membership
- Agree reference group schedule and role
- Engage with the Retailer Reference Group
- Establish partnership opportunities with customers and stakeholders (e.g ethnic communities)

Key Deliverables
This Stage 1 Final Engagement Report

A report summarising and responding to feedback and including a Final Engagement Plan.

Stage 2
Developing our Draft Plan

Aug 2024 – Feb 2025

Purpose
Running a series of engagement activities designed to inform the development of our Draft Plan.

IAP2 Spectrum
INVOLVE/ COLLABORATE

Engagement Activities
- Series of SA reference group meetings
- Iterative customer workshops across South Australia with key customer segments
- Series of Retailer Reference Group meetings
- Briefings/meetings with key stakeholders (e.g. AER Consumer Challenge Panel)

Key Deliverables
Stage 2 Engagement Findings

Summary tables/report of all feedback from Stage 2 to inform the Draft Plan.

Stage 3
Consultation on our Draft Plan

Mar – Apr 2025

Purpose
Focusing on public consultation on our Draft Plan.

IAP2 Spectrum
CONSULT/INVOLVE

Engagement Activities
- Publish and distribute Draft Plan for consultation
- Meetings/ briefings with key stakeholders (e.g. AER Consumer Challenge Panel)
- Customer workshops to consult on Draft Plan
- Combined deep dive workshops for SA Reference Group and Retailer Reference Group meetings

Key Deliverables
Draft Plan

Summary tables/report of all feedback on key areas/issues for further engagement in Stage 4.

Stage 4
Refinement and engagement

Apr – Jul 2025

Purpose
Finalising our plan and incorporating feedback received during consultation on the draft.

IAP2 Spectrum
INFORM/INVOLVE/ CONSULT

Engagement Activities
- Undertake an further engagement as required
- Meetings/briefings with key stakeholders (e.g. AER Consumer Challenge Panel
- Combined deep dive workshops for SA Reference Group meetings and Retailer Reference Group meetings

Key Deliverables
Final Plans to the AER

Submission of Final Plan with supporting customer and stakeholder engagement reports.

Stage 5
Post-Lodgement Engagement

2nd half of 2025

Purpose
Fit for purpose engagement activities designed to address specific feedback from the AER.

Some post-lodgement activities may include separate engagement by networks to address the feedback from the AER on our individual submissions.

5.2 Our engagement approach

In May 2024, we invited the following key stakeholders to collaboratively design and seek input into the development of AGN's engagement strategy, ensuring that participants are aligned on the key objectives for and approach to stakeholder engagement for the Access Arrangement:

- Multicultural Communities Council of SA
- Council of the Ageing SA
- South Australian Federation of Residents and Ratepayers Association Inc
- St Vincent de Paul Society
- Energy Users Association of Australian
- South Australian Council of Social Service
- Energy Consumers Australia
- Ai Group

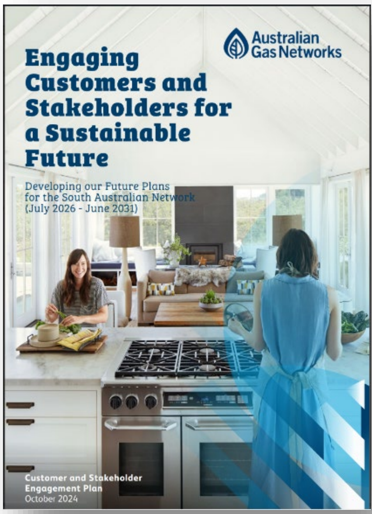
In July 2024 we published our Draft Engagement Plan with an eight-week consultation period. We distributed the Draft Engagement Plan widely and invited key stakeholder groups to provide feedback.

This was an important step in our five-stage engagement approach, as it ensured that we were engaging with relevant stakeholders and customers and giving them the opportunity to provide input into our proposed engagement activities.

To achieve this, we sought feedback on:

- our proposed stakeholder engagement program;
- our proposed engagement principles;
- our proposed engagement topics;
- our proposed engagement activities; and
- our identification of customers and stakeholders.

A summary of feedback we received on our draft Stakeholder Engagement Plan is detailed in Table 5.1. The Final Engagement Plan was published in October 2024 and can be found on our online engagement portal, Gas Matters: (gasmatters.agig.com.au).



5.3 Our customers and stakeholders

We have identified several stakeholder groups with an interest in how we plan, manage and operate our gas distribution network (illustrated in Figure 5.2).

In the early stages of engagement, we consulted with key stakeholders and sought feedback on who should be involved, to ensure that the voices of all relevant stakeholders are heard and considered.

Stakeholders across all of our engagement activities represent a cross-section of our customers, energy retailers, government agencies and other businesses that rely on the delivery of our services.

5.4 Our engagement principles

In collaboration with stakeholders, we adopted a series of engagement principles as shown in Figure 5.3. These principles guide how we engage with our customers and stakeholders.

Figure 5.2: Our customers and stakeholder groups

Table 5.1: Summary of customer and stakeholder feedback on our Engagement Plan

Customer and stakeholder feedback	Our response
Our engagement program	
Stakeholders requested detail on: • the engagement narrative and the reasoning behind why we engage. • how the Engagement Plan interacts with the AER's Better Resets Handbook.	Further detail on the Engagement Plan narrative and reference to the AER's Better Reset Handbook was included in the Final Engagement Plan.
Our engagement principles	
• Stakeholders expressed support for our engagement principles. • One stakeholder suggested we make it clear that under the engagement principle 'clear, accurate and timely communication' the information we provide is also understandable.	We incorporated the word 'understandable' into the "Clear, Accurate and Timely Communication."
Our customers and stakeholders	
• Stakeholders suggested we explicitly mention First Nations people, renters and people experiencing vulnerable circumstances as customers in the Engagement Plan.	We updated the 'residential customers and community' section to explicitly include First Nations people, renters and people experiencing vulnerable circumstances. Indigenous Australians: We strongly encourage members from local Indigenous groups to participate in any other engagement activities that are of interest to them, such as the customer workshops. If any specific issues affecting local indigenous groups arise as we prepare our submission, we will reach out to discuss these.
Our engagement activities	
• Stakeholders requested details on the digital opportunities for engagement with customers and stakeholders. • Stakeholders suggested expanding engagement activities to include an additional forum to discuss key regulatory issues at a more in-depth level.	We included more detail on digital opportunities and on additional engagement activities to discuss key regulatory issues.

Figure 5.3: Engagement principles

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 look to continually improve

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 report how we used stakeholder insights to inform plan

Clear, Accurate and Timely Communication

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

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

Ensuring engagement is accessible to all stakeholders, regardless of age or cultural, linguistic or socioeconomic background

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 to improve our approach

Integrated

We will be responsive by integrating customer and stakeholder feedback into all aspects of this work

Clear evidence that we have listened and responded to customer and stakeholder feedback in our plans

5.5 Key topics for engagement

Our engagement program covers a broad range of often complex topics. In developing the list of topics, we asked our stakeholders and customers what was most important to them. We have been guided by our customers and stakeholders on where to focus our engagement activities.

A key part of our engagement program is our customers' and stakeholders' keen interest in discussions around the future of gas. Our South Australian stakeholders were keen to learn more about our plans in South Australia for decarbonisation of gas and the future of gas more broadly, including within the national context.

In particular, stakeholders highlighted their interest in:

- how decisions we make today will impact customers in the future;
- what renewable gas could mean for customers in the energy transition (e.g. in terms of appliances, transition costs); and
- the potential role gas will play in a low carbon future, and how to best consider and respond to uncertainty.

5.6 Engagement activities and feedback

5.6.1 Customer engagement

Engaging directly with customers in the development of this plan is critical to ensure that we align our plans and proposals with customers' needs and expectations.

<u>Customer workshop methodology</u>

Our customer workshops are being run in three phases with the same group of customers, allowing iterative engagement as our plans are developed and refined.

To date we have completed two phases of workshops – in August/September and October/November 2024. Feedback obtained from the 181 customers who attended over 15 workshops has been used to shape this Draft Plan.

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

- build customer knowledge over time to allow customers to make informed decisions;
- test and validate our ideas in response to customer feedback as we develop proposals; and
- prioritise and explore issues in more detail in response to customer feedback.

We were pleased to be able to hold most of our workshops with customers face-to-face, to allow opportunities for organic discussions and which in turn further contributed to the development of our plan.

Participants were recruited through a specialist third party provider, selected to ensure the group was representative of a broad cross section of the community.

We also partnered with Multicultural Communities Council of SA (MCCSA) in hosting dedicated workshops with CALD customers in metropolitan Adelaide.

Customer workshops were facilitated by a third party (KPMG) to independently capture and document customer feedback.

We used a range of tools to ensure that workshops were engaging and interesting, including presentations from subject matter experts, interactive polling/surveying tools and the invitation for customers to ask questions throughout the 90 minute workshops.

During the workshops that were held online, the chat function was constantly monitored so participants felt like they could type their question/feedback without interrupting the presentation. Participants were encouraged to turn their microphones and cameras on, and use the 'raise hand' function on MS Teams to alert the facilitator that they had a question or comment to make.

KPMG facilitated the use of the visual online collaboration tool 'Mural' to ensure that interactive activities were as engaging for online participants as they were in the face-to-face workshops.

<u>Phase 1 Customer Workshops:</u>

181 customers attended Phase 1 of our customer workshops. These customers were recruited by a third-party agency, selecting people who would represent metropolitan, regional, residential, small business and CALD customers.

Phase 1 workshops were designed to align to our engagement principles and objectives, including listening to customer views on a range of topics, providing relevant information and committing to integrating customer feedback into our Plan.

To facilitate genuine conversation where everyone had the opportunity to have their say, the Phase 1 workshops were designed and delivered based on the following four engagement objectives:

- Build engagement: ensure participants felt welcomed, valued and were eager to return to future workshops;
- Educate: provide a sound understanding of our business, role in the gas network, regulatory oversight and demonstrate the importance of good engagement to our decision-making;
- Explore: genuinely engage with, listen to and understand what is important to participants, what they value, their preferences and what their interest areas are; and
- Prepare: understand which topics participants are interested in focusing on.

During each 90-minute workshop, subject matter experts were in attendance to present and respond to questions directly from customers. We conducted interactive activities to keep the workshops interesting.

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

We invited stakeholders to provide feedback on the most important aspects of our service and issues we should be considering in our future planning. This enabled us to focus on these topics in subsequent engagement activities in Phase 2.

During Phase 1, customers identified the following key topics as issues of importance for consideration in the development of our plans:

- Price and affordability;
- Customer service and customer experience;
- Reliability of supply;
- Public safety;
- Future of gas; and
- Regulatory building blocks.

See Table 5.2 for a detailed list of these topics for engagement.

Table 5.2: Key topics for engagement

Key topics
Price and affordability of gas bills
• Price paths • Intergenerational equity
Customer service and experience
• Services for customers in vulnerable circumstances
Reliability of supply
Public safety
Future of gas
• Renewable gas opportunities • Government policy impacts • Future Energy scenarios • Customer transition/impacts of renewable gas blending • Demand impacts • Long term planning (beyond five-year plan)
Regulatory building blocks
• Pipeline services • Setting our capital base • Depreciation • Demand forecasting • Our capital and operation expenditure proposals over the next period
Terms and conditions

In Phase 1, customers told us that:

- Price and affordability was their top priority:

  "Affordability means having a stable and reasonable gas price that fits our budget."

  "Energy is an essential service and needs to be cost effective."

- They are highly satisfied with the reliability of their gas supply:

  "Gas reliability is important to myself, home and business for washing, cooking and mechanical repairs."

- They expect efficient resolution to an issue and prefer to talk to someone directly:

  "Great interaction would include multiple options for contact – email/phone/chat on website. And timely response and action."

- Renewable energy is important to them, but affordability is a key consideration:

  "Clean energy is important as long as it's reliable and affordable."

- They are interested in the future of gas and have a strong desire to explore it further during the engagement program:

  "What are the plans to use biogas and where?"

  "Is it true that Victoria is removing/ abolishing [gas] in new houses?"

  "What does the future of natural gas look like in South Australia?"

<u>Phase 2 Customer Workshops:</u>

Of the 181 customers that attended our Phase 1 workshops, 153 returned for Phase 2. This represents an 85% return rate. See Table 5.3 for details.

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

We designed these workshops to extend and build on the foundational knowledge customers had gained in Phase 1, equipping customers with enough information to enable them to genuinely engage and provide feedback on topics aligned to their interests.

The objectives of our Phase 2 workshops were to:

- Maintain engagement: continue to ensure that participants felt welcome, valued and were eager to return to the final phase of engagement.
- Test and align: build on the knowledge of customers' priority areas by starting to test potential investments and decisions that align with customer expectations and priorities. Commit to seeking input and feedback from customers to ensure shared value is created through the decision-making process.
- Foster informed decision-making: based on knowing what is important to customers, provide more detailed information on key priorities and interest areas, and address questions to ensure customers can provide informed input and feedback during the workshops.
- Validate: confirm key feedback and insights with participants in a way that reassures participants that they have been heard and listened to.

Phase 2 workshops were generally 90 minutes in duration and included opportunities for open discussion with AGN subject matter experts.

Participants were asked to provide feedback and ask questions at the end of each topic, as well as a 2-minute paper at the end of the workshop asking participants:

- Have we covered all the issues and topics that are important to you?

- What else would you like to know in future sessions?

The key insights obtained from the Phase 2 workshops remained very similar to those obtained from Phase 1. Summarised in KPMG's Report:

- Customers were satisfied with our proposal to maintain stable prices and customer service levels (including our Priority Services Program for supporting vulnerable customers):

  "What factors are being taken into account on prices being stable in the next five years?"

- Customers strongly support our approach to maintaining gas safety and reliability:

  "Knowing AGN is staying on top of maintenance is reassuring."

  "I feel highly confident that the reliability will be maintained through this approach."

- Customers are interested in learning more about our plans to grow our gas distribution network:

  "Will new infrastructure be able to use 100% renewable [gas] and will old meters need to be upgraded?"

  "What are the challenges for regional development of new communities like the large housing developments at Gifford Hill (near Murray Bridge)?"

- Customers want to better understand the network's proposed shift to a renewable energy future and the personal impacts of the transition:

  "How will hydrogen be delivered alongside natural gas?"

During Phase 2 workshops we presented customers with information about our early price forecasts for the 2026-31 Access Arrangement period. In line with customer sentiment from Phase 1, we informed customers that we were proposing stable prices based on their feedback that

Customer feedback:

Phase 1

- ✓ "Clear and well spoken, excellent engagement. I felt heard verbally and with the post it notes. Great engagement."
- ✓ "Well organised and run workshop. The hosts and speakers were very informative. The post-it notes were a great idea for sharing thoughts and questions. Very engaging workshop."
- ✓ "I learnt about AGN and why they want to improve. I valued various viewpoints that were present. Having reps at the table was very useful."
- ✓ "Very informative and clear information given. Great staff from AGN."

Phase 2:

- ✓ "The workshop ran very smoothly and was very informative."
- ✓ "The knowledge of the presenters and their delivery was able to be understood. Not too much jargon."
- ✓ "Level of information was in depth and very informative. I valued the foresight in using renewables and hydrogen in particular."
- ✓ "Staff were very interested in getting feedback. Loved their enthusiasm, it made me feel like providing more feedback."
- ✓ "The information and slides were informative and clear. The presenters were clear and concise and having multiple presenters helped break up the session."

steady and stable pricing was the most important factor.

We presented customers with an infographic detailing how we intend to spend every dollar of the opex and capex over the 5-year period.

Summary of Phases 1 & 2 Workshops

Full KPMG reports on both the Phase 1 and 2 workshops are available on our online engagement portal, Gas Matters (gasmatters.agig.com.au).

A summary of customer feedback from Phase 1 and Phase 2 and how we responded is shown in Table 5.4.

We set ourselves a target to achieve 80% satisfaction with the way in which we engaged with our customers during these workshops. The results of this feedback are shown in Table 5.5 and have exceeded that target. We asked customers at the end of each workshop to rate the workshop as a whole, so that we could learn from their feedback and make the next interaction more positive (see Table 5.6).

5.6.2 Next steps

Our next steps in the customer engagement process are to hold Phase 3 of workshops, focussing on presenting the Draft Plan; continuing to inform and educate customers on the topics they are interested in and also further testing and refinement of proposals to inform the Final Plan.

We will be holding seven workshops across South Australia, engaging with largely the same cohort of customers that have participated in Phase 1 and Phase 2.

We will use the feedback and insights from these workshops to inform our Final Plan.

Table 5.3: Phase 1 & 2 Workshop Attendance

Location	Customer Segment	Phase 1 Workshop Attendance	Phase 2 Workshop Attendance
Adelaide metro	Residential	30	30
Adelaide south	Business	23	19
Adelaide north	Residential	23	26
Port Pirie & Whyalla (online)	Residential and business	19	13
Barossa, Gawler & surrounds	Residential and business	16	12
Mt Gambier	Residential and business	20	18
CALD	CALD customers	25	20
Additional online workshop	Residential	25	15
Total		**181**	**153**

5.6.3 Stakeholders, meetings and forums

South Australian Reference Group (SARG)

The SARG is made up of industry representatives and stakeholder advocates who represent a wide range of South Australian gas end-users, including customers in vulnerable circumstances, culturally and linguistically diverse customers, businesses of all sizes and industries, social service organisations and property developers:

- South Australian Federation of Residents and Ratepayers Association Inc
- St Vincent de Paul Society
- Energy Users Association of Australia
- SA Business Chamber
- Ai Group
- Urban Development Industry Association SA
- Multicultural Communities Council of SA
- South Australian Council of Social Services
- SA Financial Counsellors Association
- Energy Consumers Australia
- Australian Energy Council
- Renewable Gas Alliance
- Master Plumbers Association
- Property Council of Australia (SA)

The role of the SARG is to:

- provide input and feedback to inform the development of our plans, ensuring they are capable of acceptance by customers and stakeholders upon submission to the Australian Energy Regulator;

- inform and shape our engagement activities to ensure we deliver best practice, fit for purpose engagement;
- advocate in the interests of constituents to ensure our plans deliver value for all customers; and
- challenge our businesses to deliver the best possible outcomes for current and future customers.

The SARG has had input into the design of all our engagement activities. Some members have attended to observe our customer workshops, and we have presented members with key insights from customer workshops at our meetings.

The SARG has met six times between August 2024 and March 2025 in the development of our Draft Plan. A number of representatives also attended an online 'Deep Dive' online workshop on topics that they specifically highlighted they wanted to know more about.

The SARG members were interested to understand our future plans in the context of price, and importantly that our proposals are cost efficient while delivering for current and future customers. As such, we provided early price modelling to members at our meeting in October 2024. This early presentation of our prices is consistent with our commitment to our 'no surprises' approach to engagement.

<u>Retailer Reference Group (RRG)</u>

The RRG is a mechanism used to formally engage with gas retailers, who play a major role in customer experiences with our gas networks.

Five of the six gas retailers that operate in South Australia are represented on our RRG, including:

- AGL
- Alinta
- Energy Australia
- Origin Energy
- Red Energy
- Momentum (not in SA)

Through the RRG, retailers were interested in discussing some specific elements of our proposals, including reference services, terms and conditions, prices and any new program that might impact their operations (i.e. Priority Service Program).

The RRG has met seven times between May 2024 and March 2025, including face-to-face and online meetings. A number of representatives also attended an online 'Deep Dive' online workshop on topics that they specifically highlighted they wanted to know more about.

RRG members have provided feedback and insights into how our preliminary proposals may impact their business and their customers.

A summary of key topics and information presented to the SARG and RRG is listed in Table 5.7.

We anticipate that we will meet with the SARG and RRG as a collective group as we refine the Final Plan.

5.7 Developing our Draft Plan

All feedback from SARG and RRG meetings, together with feedback from customer workshops has been captured and used to shape and refine our Draft Plan.

Most chapters of this Draft Plan also include a section on customer and stakeholder engagement.

Table 5.4:Customer feedback on topics presented

<table>
<tr><th>Theme</th><th>Engagement activity</th><th>Key insights and results</th></tr>
<tr><td></td><td colspan="2">Phase 1 customer workshops</td></tr>
<tr><td rowspan="3">Price and affordability</td><td>Customers were given an overview on our pricing model, and were introduced to our Priority Services Program. This followed discussion and questions around what affordability means to customers, and what a great interaction with us would involve.</td><td>• The majority of customers across all eight workshops ranked price and affordability as the number one priority.
• Customers equate affordability with steady and stable prices.
• Affordability means not having to make lifestyle trade-offs, such as being able to keep warm over winter.</td></tr>
<tr><td colspan="2">Phase 2 customer workshops</td></tr>
<tr><td>We presented to customers a break down on how residential bills are constructed, and showed how we intend to spend every dollar in the context of operating and capital expenditure.
Customers were presented with an early forecast average residential distribution charge of $628 from 1 July 2026, subject to variables and customer preferences.
We presented to customers our capital and operating expenditure proposals.</td><td>• Customers were comfortable that we were not proposing increases to pricing, but were keen to understand our proposal in more detail.
• Customers expressed a high level of support for our proposed pricing approach to maintaining current safety and reliability levels.
• Customers were satisfied with our proposal to continue our Priority Services Program which supports customers in vulnerable circumstances.</td></tr>
<tr><td></td><td colspan="2">Phase 1 customer workshops</td></tr>
<tr><td rowspan="3">Safety and reliability</td><td>We explained what reliability and safety means to us, and asked questions relation to their views on their importance:
• Why is gas reliability important for you or your business?
• How satisfied are you with the current reliability of your gas supply? Why and how could it be better?</td><td>• Customers place a great deal of importance on uninterrupted supply of gas to their homes and businesses.
• Reliability of supply was ranked as customers second highest priority.
• Customers are satisfied with the current levels of gas reliability.
• Many customers have never experienced a disruption to their gas supply.</td></tr>
<tr><td colspan="2">Phase 2 customer workshops</td></tr>
<tr><td>We presented our proposal to maintain current levels of reliability and safety over the next five-year period, which is forecast to cost 35c in every dollar of a customer's bill.
Customers were asked:
• "Are you happy with our proposed approach to maintaining gas safety? Why or why not?"
• "Are you happy with our proposed approach to maintaining gas reliability? Why or why not?"</td><td>• 97% of customers stated they were satisfied with our approach to maintaining service reliability.
• Customers have a high degree of confidence in our public safety and reliability track record and expect this to continue over the next five-year period.
• Across the eight workshops, 11 customers expressed the need for more information on our approach to maintaining gas reliability, specifically around:
  ◦ The reliability of gas once more hydrogen is integrated, and
  ◦ Whether or not AGN will be replacing pipelines in SA based on the age of the infrastructure</td></tr>
</table>

Table 5.4:Customer feedback on topics presented (continued)

Theme	Engagement activity	Key insights and results
	Phase 1 customer workshops	
Customer experience	Customers were asked what they believed a great interaction with us looked like.	• Customers expect efficient resolution to an issue and prefer to talk to someone directly. • Customer experience was not rated a high priority for further discussion (compared to the other topics), but customers were clear that they expect good communication and simple service that is resolution-focused. • Customers often prefer interacting with real people, and having the option for online chat and SMS.
	Phase 2 customer workshops	
Customer experience	We presented to customers our proposed budget breakdown across key customer service areas, including our Priority Services Program which supports our customers experiencing vulnerability. We discussed our Customer Service Centre and other customer service areas such as public safety, network growth and network operations.	• Customers were satisfied with our proposal to continue our Priority Services Program which supports customers in vulnerable circumstances. • Some customers asked for more information on what else the 20c allocated spend to "Customer Service" would entail and after receiving more information was comfortable with proposal.
	Phase 1 customer workshops	

Renewable energy and the future of gas	We explained to customers about our clean energy initiatives, followed by a discussion and questions in relation to how important the supply of cleaner energy was to customers.
	Customers were asked whether the supply of cleaner energy was important to them.
	Customers were also asked what they would like to know more about in terms of renewable gas.
		• Customers stated that our commitment to supplying cleaner energy was important, but affordability for customers is a key consideration.
		• Customers asked:
		  • "Will the price of gas be affordable?"
		  • "Would there be an opt in for biogas or green energy usage and would there be a significant cost to the end user?"
		  • "What is the overall environmental impact of switching gas from natural to renewable when looking at the climate crisis on the whole?"
		• Customers expressed curiosity and interested in the shift from natural gas to renewable gas.
		• Customers wanted to know more about our renewable gas initiatives, cost of renewable gas and appliance compatibility.

	Phase 2 customer workshops	
Renewable energy and the future of gas	We focussed on sharing information and educating customers on the future of gas, to allow them the opportunity to genuinely engage on options. We also shared in-depth information on regulation and competition in the market and how this impacts our business in terms of depreciation. We presented a placeholder figure on customer bills.	• Customer feedback centred on seeking more information about our role in transitioning to a new energy future, as well as the direct personal impact the shift to renewable energy will have. • Customers noted they were unaware of our hydrogen project until attending these workshops. • Customers wanted to know more about the cost of renewable gas, and whether there would be incentive for customers using hydrogen as they are contributing to a positive climate change initiative. • Some customers advised the placeholder increase for depreciation was minimal, others wanted to understand in more detail the impacts.

- Table 5.5: Customer response to engagement metrics

Engagement metrics	AGN target (%)	Phase 1 result (%)	Phase 2 result (%)
The workshop information provided was clear, relevant and accurate	+80%	**96%**	**98%**
I felt genuinely listened to and heard	+80%	**93%**	**95%**
There was an opportunity to have your say	+80%	**95%**	**95%**
The workshop content was delivered in an accessible way	+80%	**93%**	**97%**
The workshop activities were engaging and educational	+80%	**97%**	**89%**
The workshop venue and time was appropriate	+80%	**97%**	**95%**
The delivery of the overall workshop was of high standard	+80%	**100%**	**97%**

Table 5.6: Tailoring workshops based on customer feedback

Phase 1 feedback	How we tailored for Phase 2
Reduce paper/printing: Some participants commented that there was too much use of paper throughout the workshop, requesting digital options to provide feedback and engage in activities.	In Phase 2, we introduced QR codes that enabled participants to share their feedback and participate in workshop activities through digital worksheets. This improved the user experience for participants as there was a significant uptake in participants utilising the QR codes.
Question time: Some participants said they really enjoyed the open question time for discussion in Phase 1, requesting that there was more of this throughout the workshop.	In Phase 2, we ensured there were additional opportunities for open question time with AGN subject matter experts and the executive team.
Logistics: Some comments from participants expressed dissatisfaction on the location of the Adelaide North venue, noting they would prefer a venue that was more accessible.	The location of the Adelaide North workshop was changed in Phase 2 to enhance accessibility and inclusivity for participants, in line with the identified engagement objectives.

We also remained flexible throughout the phases of the workshops and were committed to making real-time updates to the facilitation of our workshops in accordance with participant feedback. For example, slight visual changes were made to 'The Future of gas in the energy transition' content based on feedback from the first three workshops of Phase 2 to ensure maximum understanding and engagement from customers.

5.8 Stage 3: Consultation on this Draft Plan

The release of this Draft Plan means we are now in Stage 3 of our five-stage approach (March – May 2025) and are consulting widely with customers and stakeholders on this Draft Plan.

A series of consultation questions are included in this Draft Plan. Submissions can be made online at Gas Matters (gasmatters.agig.com.au).

To support stage 3 engagement we are:

- publishing our Draft Plan online for a four week period for public consultation;
- continuing to engage with customers in our third phase of workshops;
- continuing our meetings with the SARG and RRG; and
- offering briefings and one on one meetings with stakeholders.

These activities support engaging on the details of our plans, including in the context of our broader business plans.

5.9 Summary Feedback and Our Response

We have undertaken a range of engagement activities to support the development of this Draft Plan.

All customer and stakeholder feedback and how we have responded in this Draft Plan is shown in Table 5.4.

5.10 Next steps

We will continue to meet with the SARG and RRG members to discuss the contents of this Draft Plan and encourage members of each group to submit a formal response.

SARG and RRG members have indicated a continued interest in the Future of Gas in South Australia, so we will host a Deep Dive into hydrogen projects in South Australia shortly after this Draft Plan is released.

We will also meet with various other stakeholders, providing briefings on this Draft Plan and seeking their input into our proposal.

We will commence Phase 3 customer workshops at the start of April.

We will encourage stakeholders and customers to interact with the Orbviz platform and consultation on this Draft Plan is open for four weeks.

A range of engagement activities supporting the consultation period include a further phase of customer workshops and continued SARG and RRG Meetings. We are also offering one on one meetings and briefings with stakeholders.

An innovative way to engage with our customers and stakeholders on the Draft Plan

In strengthening our program of engagement activities and to promote breadth and depth of engagement (a key principle under the AER's Better Resets Handbook), we have partnered with Orbviz to design a digital and interactive version of the Draft Plan.

The tool presents the Draft Plan information in an engaging and interactive way. It allows customers and stakeholders to focus on the aspects of the Draft Plan that are of interest and provide feedback quickly if they wish to do so.

Orbviz does not replace this Draft Plan document, but rather complements it – providing a snapshot summary of our proposals, with detailed explanation and information in the Draft Plan document itself.

We have collaborated with key stakeholders to design the platform to ensure that it meets the needs of different customer and stakeholder groups.

We intend to use the tool at our next round of customer workshops to gain insights and feedback on the Draft Plan to inform the Final Plan.

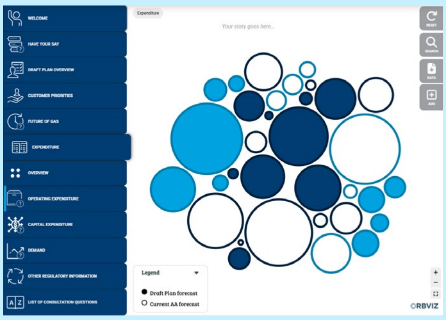


Table 5.7: Summary of SARG and RRG meetings

Meeting	Key discussions
Engagement strategy co-design workshop (May 2024)	KPMG facilitated a workshop with key stakeholders and AGN representatives collaboratively design and seek input into the development of AGN's strategy, ensuring that participants are aligned on the key objectives for and approach to stakeholder engagement for the AA.
RRG Meeting #1 and Feedback session Key Stakeholders and Feedback session (May 2024)	• Draft Reference Service Proposal • Form of Revenue Control • Tariff Structure • Stakeholder feedback
SARG Meeting #1 (August 2024)	• Business overview • Future business plans • Role of the SARG • Draft engagement plan for consultation
RRG Meeting #2 (August 2024)	• Access Arrangement overview • Draft Reference Service Proposal • Forms of revenue control • Tariff structure
SARG Meeting #2 (September 2024)	• Stakeholder engagement update • Regulatory building blocks • Capex forecasting • Accelerated depreciation
RRG Meeting #3 (September 2024)	• Overview of what we have delivered and future plans • Draft engagement plan
SARG Meeting #3 (October 2024)	• Stakeholder engagement update • Orbviz presentation • Indication of preliminary early modelling • Preliminary work on depreciation
RRG Meeting #4 (October 2024)	• Stakeholder engagement update • Orbviz presentation • Indication of preliminary early modelling • Preliminary work on depreciation • Capex, opex and demand forecasting
Deep Dive Workshop (November 2024)	• Gas policy in South Australia • AGIG's low carbon vision • Future of gas plans

Table 5.7: Summary of SARG and RRG meetings (continued)

Meeting	Key discussions
SARG Meeting #4 (December 2024)	• Tour of Hydrogen Park South Australia (Tonsley) • Stakeholder engagement update • Reference service proposal • Demand history and forecasting • Independent review into the SARG • Prices for the next AA period and preliminary modelling • AER's release of its Final Decision on our Reference Service Proposal
RRG Meeting #5	• Heating values briefing • Reference Service Proposal update • Demand forecasting • Stakeholder engagement update
SARG/RRG Meeting Online Workshop (February 2025)	• Orbviz demo • Sub-committee into review of SARG

SARG/RRG Meeting #1
(February 2025)
	• Overview of the Draft Plan:
	  • Plan highlights
	  • Opex
	  • Capex
	  • Demand
	  • Future of Gas
	  • Tariffs
	  • Network access

Questions for consideration

2. Do you have any feedback on our customer and stakeholder engagement program?
3. Have we considered customer and stakeholder feedback and responded appropriately in this Draft Plan?

6 Future of gas

We see an energy sector on the cusp of major change, where increasing use and ownership of renewable resources by consumers will release new competitive forces which will affect all energy networks. Although change will happen over decades, we need to start planning now to ensure we meet the long-term interests of our customers.

IN THIS CHAPTER:

- **We explain the changing energy landscape, its effect on competition and energy networks**
- **In this context, the regulatory framework can be utilised to maintain a stable risk balance between investors and consumers as the energy sector transitions to net zero**
- **Depreciation is a useful tool that can be used to maintain a stable risk balance and ensure a smooth transition**

The energy sector is transforming to a competitive future unlike anything we have seen before. Through this transformation, we need to act to maintain a stable risk balance between investors and consumers, to ensure we can continue to provide services which are in the long-term interests of our customers.

The energy sector is on the cusp of significant change. The full ramifications are unlikely to be seen for decades. This change is driven by the uptake of renewable electricity, though not in respect of *what* they are but rather who owns them.

In particular, for all the current focus on managing intermittent renewable electricity in an electricity grid, over the longer term, it is the fact that many renewable resources (including batteries for storing renewable power) are owned by consumers which will become increasingly important as the energy sector transitions.

Customer's control and sovereignty over their energy sources and use will have profound effects on networks. How exactly this will play out, nobody knows. Our challenge, like that of all gas and electricity networks, is to remain relevant for consumers, and the energy choices they want to make in the future. We can do this by maintaining a stable balance of risk between investors and customers, even as the energy market changes around us, an approach which underpins the regulatory framework in Australia.

If the risk balance is stable, both customers and investors can face the future with more confidence and together navigate the change in a way that continues to encourage efficient investment in and use of the network in the long-term interests of consumers.

The best way to achieve that is to do exactly what is required by the National gas Rules, to review and determine the appropriate depreciation profile with each new Access Arrangement period to ensure it remains fit for purpose.

6.1 Regulatory framework

NGR 89(1) provides that a depreciation schedule should be developed for an access arrangement period. This chapter addresses the need to consider depreciation profiles, after first providing the broader perspective which sits behind our work on depreciation.

6.2 Customer and stakeholder engagement

This is a topic we have consulted on extensively with our customers. We have sought to explain what we are doing, what the economic forces are behind what we are doing and why we are looking to act now. We have deliberately not focussed on price outcomes and customer willingness to pay, but rather on underlying issues. We will continue to consult as we move through to our Final Plan, and the AER's Draft Decision.

6.3 Change in the energy sector

The energy sector is on the cusp of significant change; a process which will take decades to unfold and whose end point is impossible to see. The driver is, we believe, renewable electricity. Much of the debate at present is about how to manage increasing shares of intermittent renewable electricity within an electricity grid using storage and different forms of firm power. However, this is a short-term technical issue.

Over the longer term, what we think will drive change is *who* owns the renewable electricty infrastructure (generation and storage), and what opportunities that gives them. Changes in this could unleash major new competitive forces.

A move from energy being provided by a third party to being produced by consumers themselves has never happened before, which means it is hard to predict what will evolve out of current trends. However, an indication of the scale of change we might expect can be gleaned by looking at a different market which has gone through this change; land transport.

Centuries ago, land transport was provided by those who consumed it (just like energy, largely); people either walked, rode a horse or used a wagon. There was, consequently, not very much of it. Then railways developed as a third-party source of land transport which required massive investments in infrastructure but which provided customers with a much cheaper, more comfortable and more reliable form of land transport. Consumption of land transport services took off.

At the close of the 19th Century, the automobile was invented and people could produce their own land transport services again, at a quality similar to that provided by railways (using roads; a differently funded, competing form of infrastructure). Take-up of these new automobiles was rapid; even more rapid than the take-up of rooftop solar today.

Rising car ownership, however, was not the end of the story. After World War 2, people realised that cars allowed an entirely new urban form and the "suburb" was born. This changed almost every aspect about how people lived and worked. In just the same way that an early adopter of automobiles circa 1905 would never have been able to predict that their grandchildren would be living in the suburbs, an early adopter of rooftop solar today has no idea how this technology might change their grandchildren's lives.

Within the context of this kind of change, two issues are key.

Firstly, given the large fixed costs of energy networks and the long timeframe over which costs are recovered, we need to plan well in advance of when we can see the future clearly if we are to navigate change in the long term interests of consumers and maintaining the risk balance between investors and consumers.

Secondly, long term infrastructure can be used into the future and repurposed. This is because re-use and repurposing is a much more efficient way for society to use infrastructure than abandoning it every time its original purpose is no longer required.

For example, when our networks carried manufactured town gas, they needed large storage tanks, called gasometers, spread throughout the network. With natural gas, they were no longer needed, and many were repurposed, rather than wasted, into apartments, sporting fields and cultural spaces (see here).

6.3.1 Renewable gas

Renewable gas (hydrogen or biomethane) is crucial for our future in the energy market, but not in the way that we have seen some stakeholders express in previous Access Arrangement processes. In prior Access Arrangement reviews some submissions have suggested that there is a dichotomy between renewable gas being successful and there therefore being no need to consider depreciation any further, and renewable gas being unsuccessful and there being a need to plan for the decommissioning of the networks. Some have even suggested that changes in depreciation and renewable gas investment are inconsistent with each other.

This misunderstands the role of renewable gas in our future. Renewable gas is a gateway to our future; without it, our social licence to operate could disappear before any competitive future such as those alluded to above eventuates. In such a world, we may need to plan for a much more radical repurposing (see above) of our gas networks.

However, if renewable gas is successful, nothing else changes in respect of future competitive forces because the sources of competition affect renewable gas just as much as natural gas. Indeed, we do not need to wait for a competitive future to arrive; as we outline below, our competition right now comes from electric appliances, and these compete with renewable gas in exactly the same way as they do with natural gas. The fact that we are planning for success in renewable gas in no way excuses us from planning for the rest of our future, or from thinking about how to use tools like depreciation to improve the agility with which we face the future.

Renewable gas is, however, of great interest to our customers; it is consistently one of the things they want to hear most about in consultation. Customers have a desire to continue to use gas and their gas appliances, but with a view to lowering the carbon footprint of their gas use in a carbon constrained future. For this reason, we summarise some renewable gas initiatives in Box 4.1.

6.4 Our response in the context of regulation

The discussion above relates to the deep future, when we are facing a very different competitive environment. That environment is not here yet. Right now, the world has not changed all that much; customers continue to connect to the network and gas is still being used in ways similar to the past few decades, and we are still regulated in the same we have been. We need to work with what we have and where we are. And the question is how we do that. This has two elements; the regulatory framework and current demand for gas.

Regulation acts to prevent a monopolist from taking advantage of their market power to the detriment of consumers. It does this by limiting the actions we can take, which circumscribes the tools we can use. The AER has developed a discussion paper dealing with how regulated pipelines might deal with future uncertainty in a 2021 information paper, which suggests eight possible options before ultimately settling on changing depreciation schedules as the most appropriate response and each regulatory decision subsequent to that for gas infrastructure has in fact changed depreciation schedules. We believe this regulatory tool is the best fit for the purpose of maintaining a stable risk balance between customers and investors as energy markets change because it takes risk off the table for both parties rather than shifting it between them.

In terms of focus, the period of time whilst we are regulated is likely to be dominated by gas performing its current role; providing heat in various forms as it is burned in homes and businesses. In this role, gas faces competition because electric appliances (air-conditioners vs gas heaters, for example) are also capable of acting as a substitute rather than the more fundamental forms of future competition alluded to above. Essentially, we are testing our ability to remain viable over the coming few decades where our current regulatory and demand environment prevails. If we can do this successfully, it means all of our customers, current and future, face the lowest long run cost for using our network.

6.5 Modelling process

The model we are using is adapted from the model we used in our recent Victorian Access Arrangement proposal (see here). The model is a customer choice model attached to a long run version of our regulatory building block model used to generate prices. In the model, in a given year customers see a price generated by the long run regulatory model and decide how much gas to use. If their appliances are at the end of their lives, they also decide whether to replace gas appliances with electric (or vice versa). The consequence of that decision is then used to determine prices for next year (in the regulatory model, price is cost divided by demand), and consumers go through the same decision-making process.

Depreciation fits in because neither relative prices nor consumer tastes are constant, so changing price by shifting depreciation from a time when relative prices are close and customers are price sensitive to a time when they are less price sensitive means that demand is less affected. Since invested capital is recovered only once, this has the net effect of each customer on average through time paying less for their gas by virtue of the fact that there are more of them during the whole period. This better spreading of costs is key to keeping the risk balance between investors and customers stable.

The change we make from our Victorian model is that, rather than relying on a small number of scenarios which each define an entire, plausible future state of the world, we make use of driver variables which have a range (or, in some cases, a series of discrete variables) and we simulate different values of each driver variable to give a range of future outcomes.

There are pros and cons of approaches that use scenarios and drivers, but we think that drivers are a better approach when dealing with the kind of competitive future we think we face.

What we do in a practical sense is pick a year (the exact year doesn't matter much) when we think the new competitive marketplace might emerge, then work out a plausible revenue stream that we ought to be able to earn in this marketplace to derive a future market value for our business in that year.

Via simulation using the different driver variables, we then test a particular depreciation profile to give a range of values for our RAB (the cost-based business value that regulators use) immediately prior to the emergence of competition. If the business value we ought to be able to support in the competitive marketplace sits just below the middle of the range of RAB values that our simulation exercise suggests will result at the end of the period of regulation for the depreciation profile we choose, then we think this represents a reasonable opportunity to earn at least the efficient cost of our invested capital; the benchmark the law requires regulators to aim for. It is worthwhile pointing out that:

- This is in no way a guarantee of asset recovery. All it does if give us the same opportunity to recover efficiently incurred capital spending we have always had, as the energy market changes.
- This is not a plan to try and meet one particular potential future outcome, like a plan to manage the decline of the network. Rather, it is an attempt to look across all potential outcomes which will, we hope, avoid the error of ignoring valid information and producing too much or too little depreciation, which does shift the risk balance from investors to customers (or vice versa).

Our modelling is not yet complete but is rather a work in progress as we gather information about the driver variables. We will consult with customers and share early results of the modelling with a final position becoming part of our final plan.

We note that, whilst a formal modelling process is a transparent way to show how information leads to conclusions, it is impossible to include every consideration into a modelling framework. Where other considerations, including, importantly, feedback from customers, lead to a different outcome from that which the model suggests, we will transparently explain why we have reached this different conclusion.

6.6 Key factors driving change

As noted above, our formal modelling focuses on the key drivers which influence the particular customer appliance choices we are modelling. The discussion of drivers below is framed around this customer choice, and what drives it.

6.6.1 Policy

Policy is obviously a key driver for gas appliance usage. Our modelling framework allows us a great deal of flexibility in this regard to cover various different environments we might face. For example, in Victoria, the government is currently considering a proposal which will ban all new gas appliances in homes. Our model accordingly has a switch which allows us to simulate demand in an environment where a certain number of customers must leave the network each year, whether they want to or not, due to a new appliance ban. The model also allows other policy options such as connection bans and subsidies.

At present, none of these policies are contemplated by the South Australian Government. Accordingly, we switch these parts of the model off, and focus on what policies are in place.

The key policy is support of the renewable gas industry in SA. What this effectively means is that the likelihood of renewable gases successfully reaching scale and lowering cost increases. In the modelling framework, we make no real distinction between types of gas in a physical sense and focus just on price. This means we can proxy success of the SA Government policy by modelling lower gas prices, with higher renewable gas blends, more quickly than might otherwise be the case.

6.6.2 Fuel price

As the modelling is focussed on gas vs electricity appliance choices, a key consideration is the price of fuel. An electric heat pump (for water or air) uses less energy than its gas equivalent because it moves, rather than creates, heat, but this is of limited benefit if the price of electricity is high. So relative prices are key.

Each price, be it electricity or gas, wraps in a number of factors, as it is the price which consumers see. So for electricity, a certain proportion of the market will have rooftop solar and, at certain times of the day get "free" (the sunk costs of their solar cells are not included in the model) electricity. We can model this by doing a weighted average of costly network electricity and free rooftop solar rather than trying to include choices involving rooftop solar into the model.

Similarly, although we explore different potential pathways for natural gas, renewable gas and carbon prices, the price paid by consumers is a combination of all three, and this is reflected in our model, rather than including models of each gas fuel source.

As a final point, drivers are not independent and have some cross correlation. Gas and electricity prices are one example. To the extent that gas is the marginal supplier of electricity, a high gas price will occur with a high electricity price. Our modelling takes this correlation into account, limiting the ability of the simulations to draw a low gas price alongside a high electricity price and vice versa.

6.6.3 Appliance price and efficiency

The other key price consideration for customers is the up-front price of gas and electric appliances. This does not stay constant through time. Nor does performance. We wrap both cost and performance into a single up-front price. Thus, if an appliance ends up being twice as efficient as it was previously, we model that as effectively being a halving of its up-front purchase price, rather than separately modelling appliance performance.

Intuitively, the customer is "seeing" the future performance of an appliance when they buy it and factoring it into what they are willing to pay; there is no real difference from the perspective of the choice a customer makes between being willing to pay twice as much for something because you know it will perform twice as efficiently, and facing two identically performing products where one is half the price.

We make this choice to simplify modelling and avoid having an ongoing performance variable to complicate the model.

6.6.4 Weather

One driver is weather. There is a great deal of debate about the comparability between gas and electric appliances in producing heat, and we recognise that factors such as insulation in the home play a key role (as does customer choice). However, it is true that, the colder it gets, the less of a substitute a reverse-cycle air conditioner is for a gas heater. It is also true that most houses now have both gas heating for winter and a reverse-cycle air conditioner for summer, as the latter is very often the cheapest and most effective cooling option

This means that, all else being equal, the fewer cold days there are, the more likely it is that a customer would use their reverse-cycle air conditioner, to save on fuel costs, given that a heat pump uses less energy.

We therefore allow for some variation in weather, changing the number of effective degree days when gas is attractive. In most cases, this only has a volume effect. However, if it persists for long enough, it may lead to a customer not replacing their gas space heater, because it is warm enough to no longer require it.

6.7 Summary

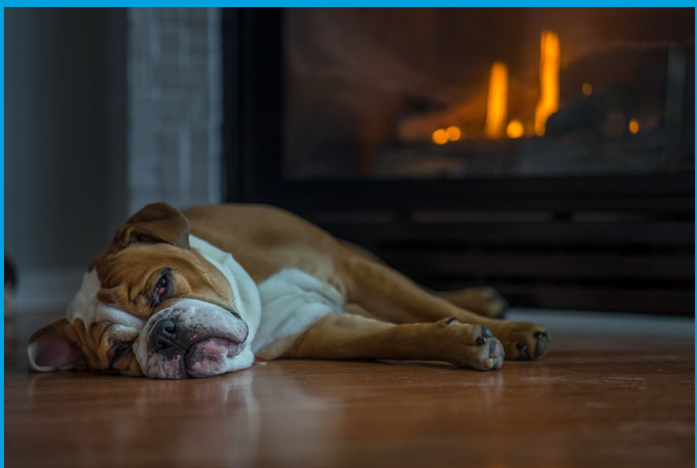
To date we have built the model we plan to use, tested it and started collecting the relevant data. We have also undertaken much of the background research which will help us sense check the final model outputs, and which has helped inform this Draft Plan. This suggests that a range for additional depreciation of between $20 and $185 million (or between $10 and $80 extra per residential bill per annum) is likely to be reasonable. The upper end we consulted on with customers late in 2024 (Phase 2 of our customer workshops) and the lower end reflects more recent information. We will continue to consult with consumers as we progress towards the Final Plan.

It is not necessarily the case that, once we have the full suite of information, the final answer will definitely lie within the band which seems reasonable at the moment. It could be above, or below.

The point of considering depreciation at each access arrangement is not that it will always get bigger because there is a certain path we are heading down and the only uncertainty is the timing of the end point.

Rather, it is that, in a dynamic market environment, this key opportunity for flexibility needs to be considered anew. Sometimes, the best answer after many months of analysis may well be to do nothing. This was the case, for example, in the recent proposal for the Dampier to Bunbury Pipeline in Western Australia, no change in depreciation from the prior proposal five years ago. Reviewing and determining appropriate depreciation profiles will become a business as usual part of regulation over coming decades.

In the context of this forthcoming AA, we remain optimistic about our ability to continue to deliver value for our customers as their needs change. We will continue to evolve our depreciation profile for the Final Plan with a view to maintain the risk balance between customers and investors in order to deliver more stable prices for customers through time.



Question/s for consideration

4. What are your views of the emerging opportunities for customers in South Australia? Are we too optimistic, too pessimistic or is it too early to tell?
5. Do you support our efforts to remain flexible as the future changes, or should our only concern be the lowest prices for the next five years with no thought of the future?

Australian Gas Networks

7 Pipeline and reference services

Our pipeline and references services for the next AA period are generally consistent with those currently provided by the South Australian distribution network.

IN THIS CHAPTER:

- **We intend to maintain the same reference and non-reference services in the next AA period, but with the addition of the abolishment service as a reference service.**
- **Our haulage reference services will continue to be complemented by a range of ancillary reference services.**

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

In the current AA period, we have offered various haulage and ancillary services.

Our haulage services and main services ancillary to providing a haulage service, such as connections and special meter reads, are classified as reference services, specifically haulage reference services (HRS) and ancillary reference services (ARS).

Reference services are determined based on 'reference service factors' (RSF) including the actual and forecast demand for the service and demand substitutability.

These services, which have accounted for more than 99% of the revenue earned in the current AA period (Figure 7.1), are the basis of the reference tariffs approved by the AER.

We plan to offer the same suite of reference services in the next AA with the addition of the abolishment service being classified as a reference service.

The AER's Final Decision on our Reference Service Proposal has approved our proposed reference and non-reference services (Table 7.1).

Our RSP submitted to the AER in June 2024 incorporated the feedback we received from stakeholders on our suite of proposed services, and classification of those services.

The following sections provide further detail on our proposed reference and non-reference services and the RSP process. Details of the price and other terms and conditions that will apply to the reference services are provided in Chapters 14 and 15 respectively of this Draft Plan.

Reference service factors

The reference service factors in the NGR require consideration to be given to:

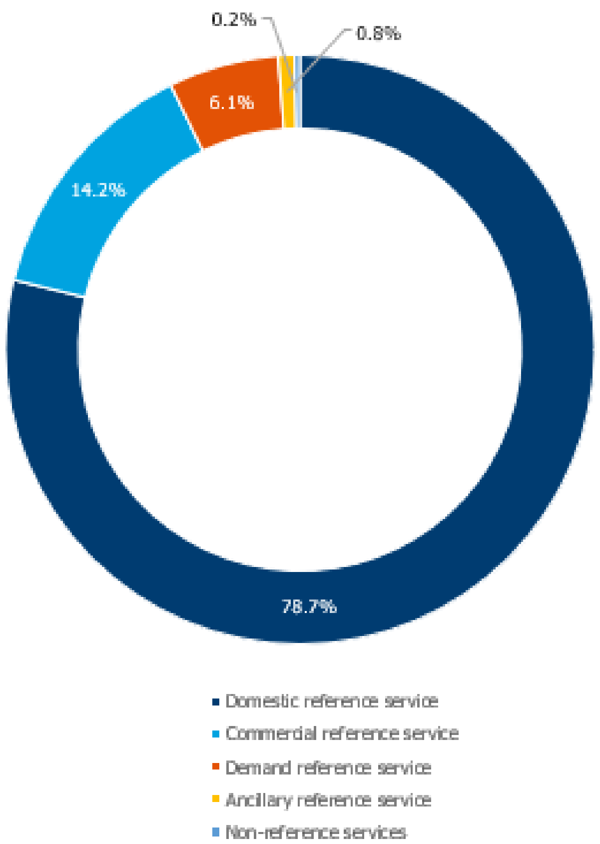
- actual and forecast demand for the service and the number of prospective users of the service;
- the extent to which the service is substitutable with another reference service;
- the feasibility of allocating costs to the service;
- the usefulness of specifying a service as a reference service in supporting negotiations and dispute resolution for other services; and
- the likely regulatory cost.

Table 7.1: Proposed services for the South Australian distribution network 2026/27 – 2030/31

Service	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. A DP is a Commercial DP at a given time if that DP is not a Demand DP or a Domestic DP at that time.
Ancillary reference services	
Special Meter Read	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.
Disconnection	The use of locks or plugs at the metering installation of a domestic or commercial DP 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 of a metering installation and the soundness of the gas installation downstream of the metering installation.
Meter Removal	Removal of a meter at a metering installation to prevent the withdrawal of natural gas at the DP.
Meter Reinstallation	Reinstallation of a meter at a metering installation, performance of a safety check and the lighting of appliances where necessary.
Service Abolishment	Cut and cap of the service within the street and removal of all above ground assets (meter etc.) This service generally applies to small scale abolishment services, which covers most residential property requests. AGN will ultimately determine which cessation of supply service is applicable to each Delivery Point.

Service	Description
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 will be charged in accordance with location as either metropolitan or non-metropolitan).
Same Day Premium Service	Request for a service on the day of request in addition to the charge for the requested service.
Relocate/Remove Service Pipe	Relocate the service or "Inlet" pipework.
Downgrade Meter Size	A retailer request for a customer's meter to be downgraded.
Pressure Change	A customer request for a change in gas pressure and may involve a regulator.
Other Negotiated Service	A network service that is different from the Reference Services on terms and conditions.

Figure 6.1 SA distribution network revenue share 2021-23



Australian Gas Networks

7.1 Regulatory framework

In accordance with the National Gas Rules (NGR), we are required to include a list of all pipeline services we can reasonably offer in a Reference Service Proposal (RSP) at the start of the AA process (NGR 47A).

In our RSP, we are required to specify which services are reference services (NGR 47A(1)(c)), with regard to the reference service factors (NGR 47A(15)), which were listed above.

On June 2024, we provided our RSP to the AER for the next AA period. This proposal provided for a consistent set of reference and non-reference services in the next AA period. It also included the abolishment service being classified for the first time as a reference service.

The AER consulted on this proposal with stakeholders and in November 2024, approved our proposal for service offerings (Final Decision).

Our proposal to offer reference and non-reference services in this Draft Plan must be consistent with the AER's RSP decision, unless there has been a material change in circumstances (NGR 48(1)(b)).

7.2 Customer and stakeholder engagement

Our proposed services in this Draft Plan reflect the feedback we received from our customers and other stakeholders.

We shared our proposed list of services in our Draft Reference Service Proposal, which we published for comment on 22 May 2024.

In this proposal, we asked our stakeholders whether they:

- supported the proposed reference services
- preferred any classification changes for specific services from reference to non-reference, or non-reference to reference
- had any suggestions for improving the descriptions of our services, and
- required any additional services.

We received five submissions on our Draft RSP. We also shared our proposed reference and non-reference services in our customer workshops and with our SARG and RRG.

Our stakeholder engagement demonstrated broad support for the continuation of our service offerings.

One aspect of our engagement concerned the abolishment service, which involves permanent disconnection with cutting and capping of the service at the main (for small scale connections). We now classify this type of service as a reference service for our distribution networks in Victoria.

The abolishment service is currently offered free of charge in SA for public safety reasons, to reduce the risk of network assets being left idle.

Our Draft RSP noted how the policy landscape concerning new gas connections in SA is different to that in Victoria. It also noted how the current rates of abolishment in SA remain stable at a relatively low level and currently reflect abolishments for 'knock down rebuilds' where the gas service is removed and then reinstalled for a new home.

Some stakeholders indicated the importance of the abolishment service being classified as a separate service, in the interests of transparency and to cater for any possible future increase in demand.

Our classification of the abolishment services as a reference service in our Final RSP responded to feedback from stakeholders and is discussed further below.

Engagement insights

Customers support the continuation of our existing set of reference and non-reference services.

Stakeholders generally support the abolishment service being identified as a separate service

7.3 Pipeline services

Table 7.1 sets out the reference and non-reference services we propose to offer in the next AA period.

The classification of the services in this table as either reference or non-reference services is broadly consistent with the classification that applies in the current AA period. It is also consistent with our June 2024 RSP, which the AER approved in November 2024.

7.3.1 Reference services

In the next AA period, we propose to offer three haulage services (Domestic, Commercial and Demand Haulage) and seven ancillary services for connection, disconnection and meter-related services.

As Figure 7.1 shows, these services make up more than 99% of our revenues in the current AA period.

Consistent with the reference services factors, these services:

- are the most sought after services by our customers;

- are not generally substitutable with other reference services;
- have largely predictable costs that can either be attributed to individual users or reasonably allocated across users of a particular service; and
- can aid prospective users in access negotiations and dispute resolution for other pipeline services, thereby minimising regulatory costs for all parties.

We are proposing that the abolishment service is an ancillary reference service for the first time on our South Australian network. The proposed classification of the abolishment service as a reference service in our Final RSP reflects:

- consistency with the current AAs applying to our Victorian distribution networks;
- how the abolishment service can be considered to meet the reference service factors under NGR 47(A)15 in that there is currently moderate demand for the service and because it is not substitutable with any other service, and
- that we can allocate costs for this service for residential properties and other small scale abolishments, because they are relatively standard in scope.

At this stage, we propose that the abolishment service charge is determined in a manner consistent with the AER-approved approach for the Victorian distribution networks and the Jemena Gas Network. This is a partial cost recovery approach, and would represent around 20% of the total cost of the service, with the remaining costs socialised across other customers.

To be clear however, we do not consider this charging approach sustainable in an environment of government intervention to promote disconnection from the gas network. In such a situation, full cost recovery from the customer, as opposed to socialised across other customers, is appropriate and better aligned to the requirements of the NGR.

We welcome feedback on the preferred pricing approach.

Other ancillary services such as meter gas and installation test or meter reinstallation have been specifically requested by retailers or other stakeholders to be reference services in previous periods.

7.3.2 Non-reference services

In the next AA period, we also propose to offer certain non-reference ancillary services (Table 7.1). These services have been classified as non-reference services because they do not meet one or more of the reference service factors, particularly those relating to substitutability, consistency of demand (especially considering demand for these services is often low), and the ability to allocate costs efficiently (since the cost of providing the service varies markedly depending on the specific customer requirements).

7.4 Summary

We propose to maintain the current set of reference and non-reference services in the next AA period, but with the addition of the abolishment service as a reference service.

Our customers support this approach, which is also consistent with our Reference Services Proposal approved by the AER in November 2024.

We will continue to consult on the preferred pricing approach for the abolishment service.

Questions for consideration

6. Do you think the pipeline and reference services we have proposed are appropriate, or do you think there has been a material change in circumstances that would warrant a change to the reference services that were approved by the AER in November 2024?
7. Do you think the new abolishment reference service should be charged at partial cost recovery (e.g. for a charge of around $250) or full cost recovery (e.g. around $1,250)?


Safety
UniSafe

8 Operating expenditure

We will continue to maintain an efficient operating program for our customers as we seek to prudently address key market challenges.

IN THIS CHAPTER:

- **Our opex forecasts have been developed using the base-step-trend methodology approved by the AER.**
- **Opex in the next AA period is forecast to be 9% higher than current AA period benchmark, excluding our proposed change to capitalisation.**
- **Our opex forecast ensures we continue to provide the safe, efficient, reliable and high-quality service our customers value while also supporting emission reduction initiatives for a sustainable future.**

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.

Consistent with our approach across our regulated gas networks, we have developed our opex forecast for the next AA period by adopting the AER's preferred base-step-trend methodology. This means that 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 having regard to the individual factors that drive those costs and where the base-step-trend is not the best approach to forecast future costs. A good example of this is our unaccounted for gas (UAFG) costs. We also consider any new operating costs that we will incur over the AA period.

On an aggregate basis, our opex is currently forecast to be $481 million over the next AA period (see Table 8.1).

Some of the proposed increase in opex can be attributed to the increased costs associated with UAFG, which reflects the higher gas prices that we expect to pay.

Excluding the effect of our proposed change in capitalisation policy (see Section 8.4.1) and UAFG, our current forecast is $423 million, which is around 9% higher than our allowance of $389 million for the current AA period ($2025/26). It is 24% higher than our forecast actual opex performance of $340 million (also excluding UAFG) (Figure 8.1).

In most cost categories, we have experienced an increase in costs from midway through the current period which flows through to the next AA period. There are a range of reasons, such as the increasing costs of repairs and maintenance to meet new traffic management legislation, and higher costs of spoil management, reinstatement and dumping. Meeting Security of Critical Infrastructure (SOCI) cybersecurity obligations is also driving increased costs.

From 2025/26, we will also be introducing the Critical Mains Management Plan, which increases network patrols on the network, and the SCADA alarm management and control program at a national level.

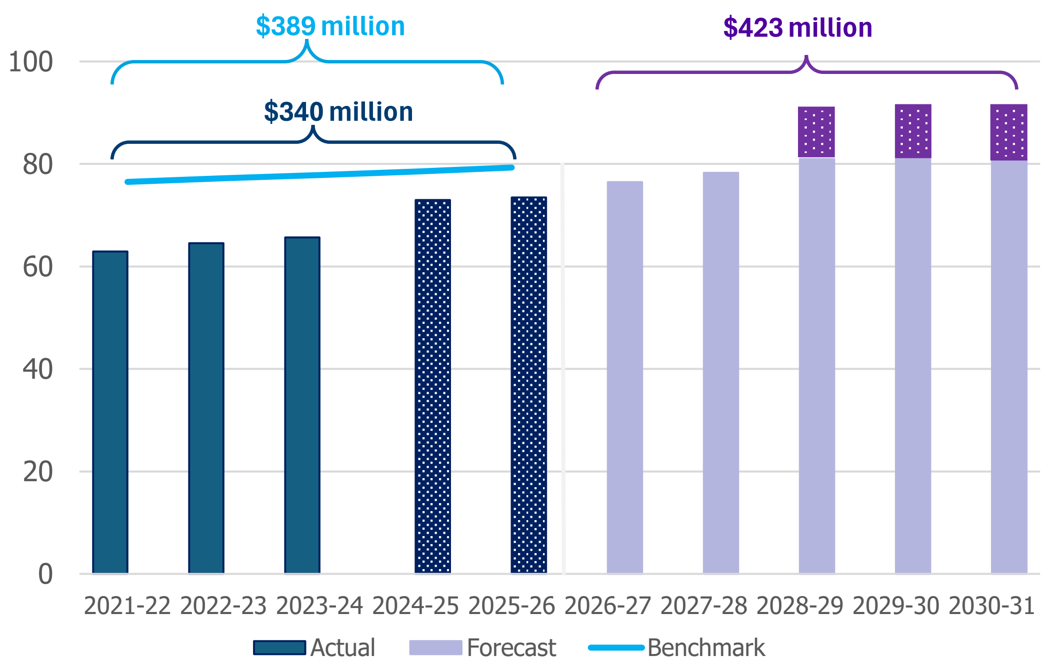
From 2028/29, we have potential step changes increasing our cost base, as discussed in Section 8.5.1. The spotted dark purple sections of the columns in Figure 8.1 highlight one such step change for the potential costs of purchasing certificates for the new renewable gas opportunity for HyP Adelaide.[1] Although an increase in opex is expected to flow into the next AA period (as shown in Figure 8.1), the opex incentive mechanism under which we operate, coupled with our internal and external controls, will continue to ensure that the opex we incur is both prudent and efficient.

Table 8.1 Total forecast opex ($million, 2025/26)

	Current AA period	Next AA period		Drivers for change
Opex (ex UAFG and capitalisation policy change)	340.4	422.9	✓	Cost pressures which have emerged in the current AA and key step changes, including for a potential new renewable gas opportunity (HyP Adelaide) and IT transition costs, plus the 'trend' component of our opex forecasts (real cost escalation and customer growth less productivity)
Proposed change in capitalisation	-	32.8	✓	We are proposing to reduce the level of overheads that are capitalised into our asset base
UAFG	20.6	25.1	✓	Reflects the increase in the cost of gas, and continuing trends in the volume of UAFG
Total opex	**361.1**	**480.8**		

Note: Totals may not add due to rounding

Figure 8.1: Opex excluding UAFG and changes to capitalisation of overheads ($ million, $2025/26)



[1] Hydrogen Park Adelaide (HyP Adelaide) is a proposed 60 MW renewable hydrogen production facility located at SA Water's Bolivar wastewater treatment plant, that will aim to produce up to 700 TJ per year of renewable hydrogen.

Our revenue in the next AA period is expected to be $22 million lower than it otherwise would be due to a negative carryover amount from the incentive scheme. This will predominantly offset any increase in the base year (as discussed in Chapter 13).

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.

All numbers quoted are expressed in 2025/26 dollars, unless otherwise stated.

8.1 Regulatory framework

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

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

8.2 Customer and stakeholder engagement

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

Customers were supportive of continuing with the Priority Services Program to assist customers in vulnerable circumstances.

We have engaged with our customers and stakeholders in the development of our opex proposal. We shared our preliminary modelling with our reference group members in September and October 2024 and presented our draft proposal and sought feedback on our investment priorities and level of expenditure in February 2024.

Stakeholders were keen to understand the proposed HyP Adelaide project opportunity and associated regulated expenditure. We will hold a deep dive meeting with interested stakeholders during the Draft Plan consultation.

Engagement insights

- ✓ Customers expect a high level of public safety and feel that safety is currently well managed.
- ✓ Customers highly value an uninterrupted supply of gas in their homes and businesses and are satisfied with current levels
- ✓ Customers support a proposed approach to maintaining current levels of safety and reliability.
- ✓ Customers are satisfied with current customer service levels, with a preference for interacting with AGN directly and also through a variety of digital channels.

8.3 How we develop our opex forecast

Our opex forecast for the next AA period has been developed using the base-step-trend approach. Figure 8.2 provides an overview of this approach.

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, ancillary reference service (ARS) and UAFG costs).

We have also used bottom-up costing for our proposed step changes.

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

8.4 Our opex forecast for the next AA period

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

Figure 8.2: 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)

8.5 Base year opex

Selecting our base year

Under the base-step-trend approach, the actual costs incurred in the penultimate year of the current AA period are used as the basis for forecasting costs in the next AA period. This year represents the most up to date actual cost information available at the time that the AER will make its decision.

The penultimate year of the current AA period is 2024/25. At this point, we do not have the actual costs for this year. We have therefore based our estimate of 2024/25 on the actual opex incurred to December 2024 and a forecast for the remaining six months of the financial year.

When we submit our Final Plan to the AER on 1 July 2025, more information on our actual opex in 2024/25 will be available. We intend therefore to update this forecast with nine months of actual data and three months of forecasts when we submit our Final Plan.

By the time the AER makes its Draft Decision towards the end of 2025, we will be able to provide a full year of actual opex for the 2024/25 base year.

Removal of non-recurrent opex

As noted in Figure 8.2, once the base year costs are determined, it is adjusted to remove any non-recurrent costs.

The opex we have forecast to incur in 2026/27 reflects our current forecast for expenditure on recurrent activities. We will continue to review and refine our forecast for our Final Plan.

Inclusion of other recurrent opex

We must also adjust the 2026/27 estimate for any new recurrent expenditure that occurs in 2025/26, after the base year (from 2024/25) has been established.

From 2025/26, we will also be introducing the Critical Mains Management Plan, which increases network patrol requirements, and the SCADA alarm management and control program at the national level.

We have estimated that these initiatives which are important for maintaining the safety and reliability of the network, will add $0.5 million to recurrent opex from 2025/26.

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 are required to better estimate efficient costs.

As noted above, we have developed separate forecasts for the costs associated with ancillary reference services (ARS) such as connections and special meter reads, UAFG and debt raising costs. As shown below (Table 8.2), we have excluded the estimates for these costs from the 2024/25 base year estimate.

Table 8.2: Establishing the base year for forecasting opex in the next AA period ($2025/26)

Category	2024/25 forecast
Total opex	75.1
Minus ARS	2.4
Minus UAFG	4.3
Minus Debt raising costs	2.4
Base year for forecasting	**66.0**

Base year opex used for forecasting

The base year opex that we have used for the purposes of the Draft Plan is $66.0 million. This amount will need to be updated ahead of the Final Plan and following the AER's Draft Decision to reflect the actual costs incurred in 2024/25.

While some revisions may need to be made, the revised costs can be assumed to be both prudent and efficient given the operation of both:

- the opex incentive scheme (see Chapter 13), 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 section 9.7), the objectives of which are to ensure we undertake opex in a prudent and efficient manner, in accordance with good industry practice.

The AER has noted in the past that unless it has evidence that the revealed opex in a proposed base year is materially inefficient, that it can use the revealed costs of the service provider for its alternative opex forecast."[2]

8.5.1 Step 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 from changes to legislation, regulatory obligations or new activities.

We have identified four potential step changes in opex over the next AA period, as follows:

- changes in our approach regarding the capitalisation of overheads and a more efficient allocation of a share of these costs to opex ($32.8 million). More information on this proposed change is provided below.
- the purchase of certificates for a new renewable gas opportunity for the HyP Adelaide hydrogen facility ($26.3 million). See Box 4.1 for a further description of HyP Adelaide. More information will be provided in our Final Plan as the project progresses; and
- transition costs for insourcing the service delivery contract at the end of its 30-year term (on 1 July 2027) ($7.7 million).

We were also considering a small step change of $0.3 million to cover higher insurance premiums in real terms. Following feedback from our most recent stakeholder meeting held 27 February we will absorb the cost, rather than identifying it as a step change. We welcome feedback on this approach.

Accounting for changes to capitalisation of overheads

As indicated above, one of our main step changes proposed in our Draft Plan is for a portion of capitalised overheads to be expensed from 2026/27.

Our capitalised overheads account for around $11 million of expenditure per year. These overheads relate to activities undertaken, such as:

- operations and maintenance for capital projects, including senior management costs;
- network analysis, design, mapping and costing support in relation to network extensions and modifications;
- costs associated with procurement of vehicles;
- technical assurance, which includes technical audits, employee training and competency assessment;
- costs of providing design and engineering services for high-pressure and non-standard distribution assets; and
- indirect costs to support the provision of the above activities such as human resources and HSE.

Consistent with our approach for our distribution networks in Victoria, we have identified a portion of these activities which are more akin to operating expenditure than capital expenditure. These activities are:

- operations and maintenance for capital projects, including senior management costs
- costs associated with procurement of vehicles; and
- indirect costs to support the provision of the above activities such as human resources and HSE.

To account for this capitalisation policy change in the opex forecast, 59% of the forecast capitalised overheads from 2026/27 to 2030/31 have been included in our opex forecasts. This results in a proposed opex step change totalling $33 million (averaging $6.5 million each year). An offsetting change has been made to lower our capex forecast for the next AA period.

Therefore, the reclassification of these costs will have no effect on our overall costs, because the increase in opex arising as a result of the reclassification will be offset by a reduction in capex.

Reclassifying these activities as opex is considered a more efficient option for expenditure allocation and reduces the growth in our asset base.

8.5.2 Trend

The final element of the base-step-trend approach requires consideration to be given to the extent to which our costs are expected to change over the next AA period from:

- input cost escalation;

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

- output growth; and
- productivity growth.

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

For the purposes of the Draft Plan, we have assumed a trend rate of change, averaging 0.9% per year from 2026/27.

Further detail on the key determinants of this rate of change is provided below.

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: [3]

- labour costs are assumed to account for 71% 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; and
- materials costs are assumed to account for 29% of our opex, on average, 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 a weighted average of the Wage Price Index forecasts for Electricity, Gas, Water and Wastewater Services in South Australia and Construction Industry, developed by Oxford Economics.

The materials cost growth rate is based on the growth rate assumed by the AER in recent regulatory decisions for AGN, which is zero.

The application of these assumptions results in a real (i.e. before inflation) average annual input cost escalator of 0.8% per year over the next AA period.

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 forecast growth in:

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

These forecasts, which are also incorporated in our capex and revenue forecasts in Chapters 9 and 14 respectively, have been weighted consistent with the AER benchmark rates, with customer numbers given a 51% weighting and kilometres a 49% weighting.

The application of these assumptions results in an average annual output growth rate of 0.6% per year over the next AA period.

Productivity growth

In applying the 'base year roll-forward' approach, the AER considers whether there should be an adjustment to capture the benefits of any potential future efficiency gains by the business.

We considered this issue in our recent AGN Victoria and Albury AA (from 2023/24). The AER had approved productivity factors in its Draft Decision, before Victorian policy developments impeded the growth of the network and productivity improvements were no longer considered feasible.

We therefore applied a productivity growth estimate of 0% per year in our AGN Victorian and Albury AA, which was accepted by the AER.

Given that the policy environment is different in SA compared with Victoria, we have proposed the productivity improvements that were initially endorsed by the AER for our AGN network in Victoria. There are scale benefits and other synergies across our network operations. This assumption also continues the annual average productivity growth (of 0.4%) which applies to our opex allowance in the current AA period.

8.5.3 Category specific forecasts

As noted above, separate forecasts have been developed for 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.

For the purposes of this Draft Plan we have assumed the volume of UAFG is equal to the annual average volume of UAFG our SA network has experienced in the last three years.

Our UAFG forecast has then been calculated by multiplying:

- the annual average volume of UAFG in the last three years; *by* the forecast average price of gas, which is based on current market indications for securing firm gas to meet our UAFG quantity requirements in the next AA period.

The application of this method produces a forecast of $25 million for the next AA period.

In a similar manner to our current AA, we are proposing to deal with the uncertainty surrounding the forecast gas price through the inclusion of a 'true-up' adjustment in our tariff variation mechanism.

In effect, this means that if the actual price we are required to pay for gas is lower (higher) than forecast, then the lower (higher) price will be passed through to our customers.

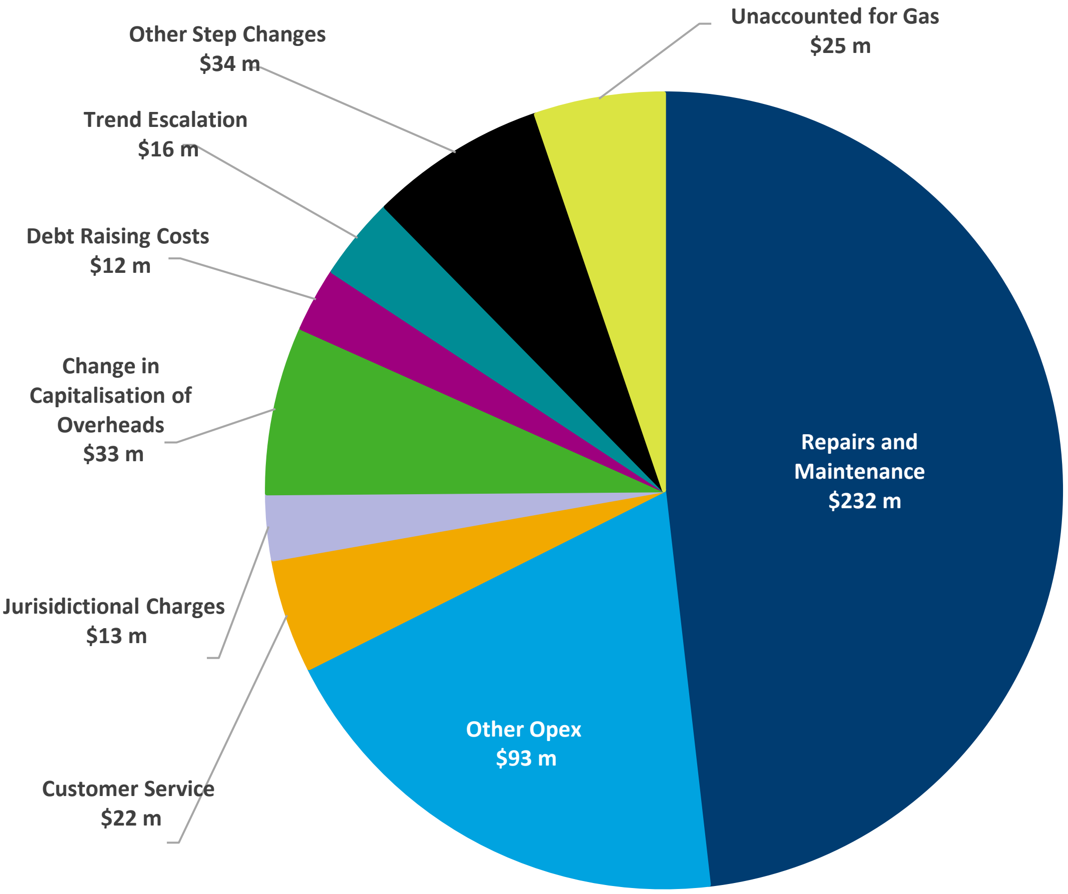
Debt raising cost forecast

Debt raising costs are the costs businesses incur when raising or refinancing debt and the costs associated with maintaining a debt facility.

Our debt raising cost forecast is $12.5 million over the next AA period.

In our Final Plan, we propose to adopt the Economic Regulation Authority (ERA) method of applying 16.5% of notional debt for debt raising costs. This approach is similar to the AER's preferred benchmark method (from 2004) but is updated by the ERA in its 2022 Rate of Return Instrument (RoRI) with more recent market data.

Figure 8.3: Opex forecast for next AA period by category ($ million, 2025/26)



8.6 Summary

Figure 8.3 and Table 8.3 over the page set out our forecast opex (by category and in aggregate) for the next AA period.

As this shows, we expect to incur $481 million in opex over the next AA period. Almost 7% of our opex forecast is for a change in capitalisation policy regarding our overheads, which does not change our total expenditure (combined opex and capex), but rather, is a more efficient allocation of this spend.

Our projected opex in the next AA period is prudent and efficient amidst a range of market challenges, including a higher cost operating environment and the energy transition. It aligns with our strategic vision by:

- Being **customer-focussed** – we will respond to leaks on our network (to ensure public safety) and maintain our network assets as required by our asset management plans, along with other operational activities to maintain our strong safety, reliability and customer service performance. We remain focussed on how we can strengthen the customer experience of the next AA period, which includes continuing our Priority Services Program for customers experiencing vulnerability into the next AA period (see the box adjacent);
- Being a **leading employer** – we will continue to undertake workplace health and safety programs, and employee and contractor training and development initiatives to maintain a healthy, safe and skilled workforce;
- Achieving **operational excellence** – almost half of our proposed opex is for repairs and maintenance expenditure ($232 million) integral to the reliability of the network. Customers are protected to a large degree from the upward cost pressures we are facing by the operation of the opex incentive scheme and the effective price reduction it offers in the next period. We are also proposing continued efficiency through our labour productivity factor; and
- Fostering **sustainable communities** – by building on the past success of projects such as Hyp SA

Our Priority Services Program

Since the launch of our Priority Services Program in SA in 2023, we have made a meaningful impact in providing assistance to our priority customers:

- In June 2024, we implemented an upgraded Customer Relationship Management (CRM) system to support customer registrations.
- We have around 100 South Australian customers under the program (up until 28 February 2025) with:
  - Gas appliance safety checks
  - Emergency gas appliance repairs
- We launched an accessibility toolbar for our Australian Gas Networks website in February 2025.
- We established a dedicated priority 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.
- We participated in the South Australian Financial Counsellors Association (SAFCA) inaugural Bring Your Bills Day in Northern Adelaide to connect directly with customers.

We have also continued to work with stakeholders from the social and community services sector, along with our Trade Partners, to continue to refine and promote the program.

Our Priority Services Program was awarded the 2024 Service Champion for the Customer Service Project of the Year – Customer Impact by the Customer Service Institute of Australia through their annual Australian Service Excellence Awards.

We look forward to continuing this important program and assisting our priority customers into the next AA period.

(Hydrogen Park SA),[4] we will continue to deliver sustainable infrastructure for SA into the future.

We welcome feedback on our approach to forecasting opex as well as our opex forecasts and individual proposals for the next AA period.

As stated, we will need to make some revisions to our forecasts when submitting our Final Plan to the AER and then again in response to the AER's Draft Decision. We will be seeking to incorporate feedback from our customers and stakeholders in refining our final proposals.

Questions for consideration

8. Do you have any feedback on the operating activities we have proposed as part of our forecast for the next AA period?
9. Do you support our approach to forecasting opex? Is there sufficient information to understand our proposals and the basis of the costs included in our forecasts?

Table 8.3: Opex forecast summary ($ million, 2025/26)

	2026/27	2027/28	2028/29	2029/30	2030/31	Total
Base year opex forecast	69.7	69.7	69.7	69.7	69.7	**348.4**
Change in capitalisation	6.9	6.6	6.4	6.6	6.4	**32.8**
Other step changes	0.0	1.3	12.0	12.0	9.0	**34.3**
Trend factors	2.0	2.5	3.2	3.9	4.6	**16.2**
UAFG	5.0	5.0	5.0	5.0	5.0	**25.1**
Ancillary Reference Services	2.3	2.3	2.3	2.4	2.4	**11.7**
Total opex forecast (exc. debt raising costs)	**85.8**	**87.4**	**98.6**	**99.5**	**97.0**	**468.4**
Debt raising costs	2.5	2.5	2.5	2.5	2.5	**12.5**
Total opex	**88.3**	**89.9**	**101.1**	**102.0**	**99.5**	**480.8**

[4] Located at the Tonsley Innovation District, HyP SA is an Australian first project that produces renewable hydrogen gas. HyP SA commenced production in May 2021, supplying 700 customers with an up to 5% (by volume) renewable gas blend, and was then expanded in March 2023 to supply a further 3000 customers in Adelaide's south in the suburbs of Mitchell Park, Clovelly Park and parts of Marion. This includes households, businesses and schools.

9 Capital expenditure

Our capex forecast is lower compared to the current AA period and focusses on maintaining our strong safety, reliability and service performance.

IN THIS CHAPTER:

- **Investing $506 million in capex, a 9% reduction relative to the current period forecast while sustaining our strong track record of network safety, reliability and customer service**
- **Targeted protected steel mains and continued muti-user services replacement following the successful completion of low-pressure mains replacement in the current period**
- **Connecting around 31,000 new customers over the next AA period, ensuring our network remains capable of meeting evolving customer requirements**

The capex we incur is necessary to ensure gas is supplied in a safe and reliable manner, and to continue to deliver valued services to our customers.

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:

- are customer focussed;
- promote operational excellence;
- enable us to be a leading employer; and
- support sustainable communities.

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

Our capex is forecast to be around $506 million in the next AA period, which is 9% ($53 million) lower than what we expect to incur over the current AA period (see Table 9.1).

More specifically, our expenditure on mains replacement will substantially decrease as we complete the replacement of our low-pressure mains in the current AA period.

Offsetting this reduction is the continued uplift to unit rates reflecting significant real cost labour and contractor cost increases post Covid, as well as changes to traffic management requirements.

The following sections provide further details on the regulatory requirements in relation to capex forecasting, the methodology used and our expected expenditure in the next AA period.

Table 9.1: Actual and forecast capex by our strategic pillars ($million, 2025/26)

Vision	Current AA period	Next AA period	Drivers for change
Customer focussed	$196.3	$223.1	✓ New customer connections ✓ Higher rates and volumes for meter replacement ✓ Digitalisation and modernisation of customer service
Operational Excellence	$350.5	$242.0	✓ Lower volume of mains & services integrity programs ✓ Continued replacement of Multi-User Services. ✓ Upgrade of field assets (such as regulators and valves) to maintain network integrity, reliability and safety.
Leading Employer	$12.2	$18.5	✓ IT integration, infrastructure renewal, and replacement of vehicles and small plant equipment
Sustainable Communities	N/A	$22.4	✓ Piecemeal replacement of protected steel mains
Total	**$559.0**	**$506.1**	

This chapter also provides an overview of our performance during the current AA period and outlines our approach to ensuring that the capex we incur is both prudent and efficient.

All financial figures quoted in this section are expressed in 2025/26 dollars including overheads and escalation, unless otherwise stated.

9.1 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.

The key objectives driving forecast capex include, but are not limited to, the following:

- maintaining and improving safety;
- ensuring pipeline integrity;
- complying with our regulatory obligations;
- maintaining our ability to meet customer demand on the gas network; and
- assisting in achieving South Australia's emissions reduction targets through the supply of services.

Any forecast or estimate we provide must be arrived at on a reasonable basis and represent the best forecast or estimate possible in the circumstances. Furthermore, the overall economic value of the expenditure must be positive, including value accruing due to a reduction in emissions driven by the expenditure.

9.2 Customer and stakeholder engagement

We have developed our capex proposal in consultation with our customers and stakeholders.

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

Engagement insights

- ✓ Customers expect a high level of public safety and feel that safety is currently well managed.
- ✓ Customers highly value an uninterrupted supply of gas in their homes and businesses and are satisfied with current levels
- ✓ Customers support a proposed approach to maintaining current levels of safety and reliability.
- ✓ Customers are satisfied with current customer service levels, with preference for interacting with AGN directly and also through a variety of digital channels.

Customers highly value our track record of performance for both reliability and public safety and expect this to continue.

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 aimed at enhancing online services for our customers, for instance notifications around connection and disconnection.

We have developed our capex proposal in consultation with stakeholders. We presented our early capex proposals to our reference groups in September and October 2024 before presenting our full proposal in February 2025 which included our network asset integrity management, meter renewal, IT expenditure forecast, network augmentation and expected customer growth.

Stakeholders were keen to understand that our costs are efficient. We have demonstrated this in section 9.7 of this Chapter.

9.3 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 9.1 shows our actual and forecast capex over the current and next AA period.

We are on track to deliver the entire low pressure mains replacement program in the current period as planned. We are incurring higher costs over time in relation to our mains replacement, meter replacement and growth capex, primarily driven by unit rates.

By the end of the current AA period, all cast iron, unprotected steel, and other high-risk low/medium-pressure mains will be removed from our network. Going forward, the program will continue on a smaller scale with targeted, proactive replacements of protected steel mains that operate at higher pressures.

We are also on track to deliver our IT program within benchmark in the current period

9.4 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.

Figure 9.1: Current and next AA period forecast capex

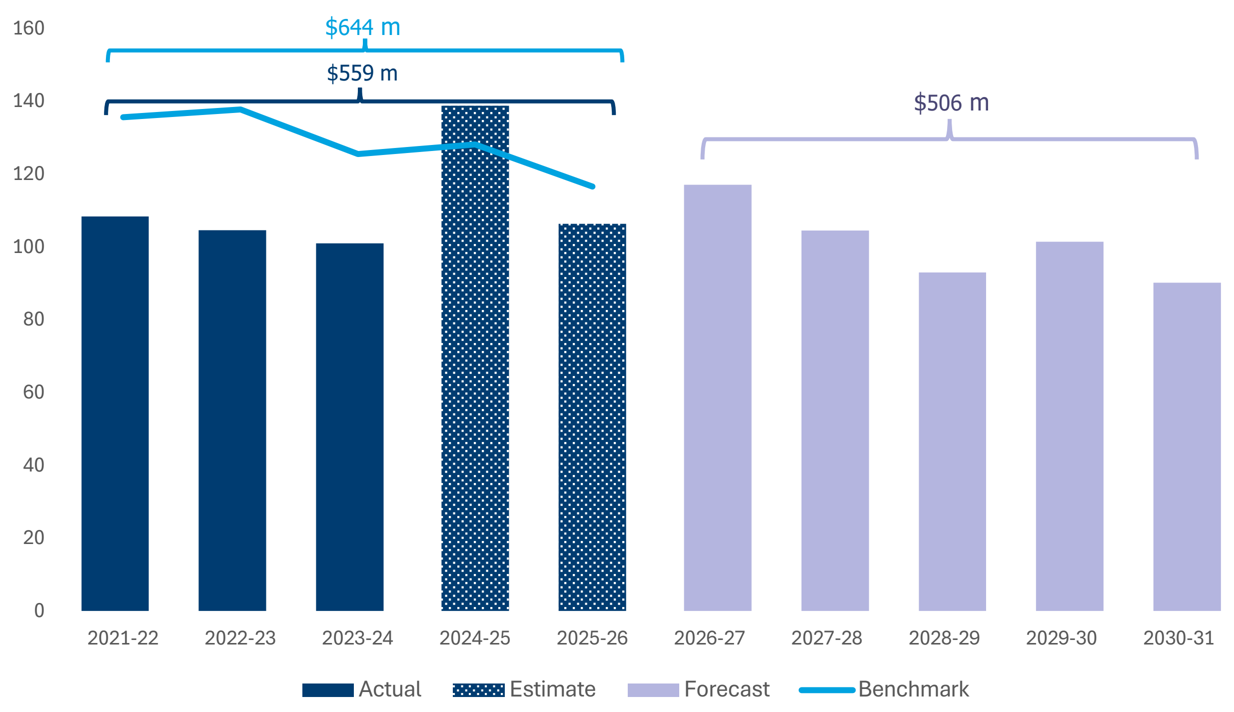


Figure 9.2: How we develop our regulatory business cases and AGN's risk matrix

RISK MATRIX

Likelihood	Impact: Catastrophic	Major	Significant	Minor	Minimal
Frequent	Extreme	Extreme	High	Intermediate	Low
Occasional	Extreme	High	Intermediate	Low	Low
Unlikely	High	High	Intermediate	Low	Negligible
Remote	High	Intermediate	Low	Negligible	Negligible
Rare	Intermediate	Low	Negligible	Negligible	Negligible

Health and Safety
Environment
Operational Capability
People | Compliance
Reputation & Customer | Financial

9.4.1 Determining our investment priorities

Most of our investment reflects the continuation of existing programs that we undertake to ensure strong safety and reliability of our network and compliance with our regulatory obligations.

The process used to identify projects for delivery is shown in Figure 9.2. As this figure shows, potential projects and program activities are identified by asset managers having regard to our AMS, AMP, risk management framework, regulatory obligations and projected network growth.

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

For the higher ranked programs proposed within the regulatory period, comprehensive business cases are developed to facilitate a more detailed assessment of the options available to address the identified issues while ensuring the costs of these options are considered and that the relevant provisions in the NGR are met.

In contrast, programs that are lower ranked or discretionary are typically deferred.

Mains replacement in the next AA period will be on a much smaller scale than the current AA period and will focus on small sections of protected steel mains in the network. This follows the significant replacement program of old low pressure mains that has been a key focus in the current and prior AA periods that has seen around 3,000km replaced over nearly the last three decades.

We are also proposing to invest around $3m in a number of new projects to improve our customers' digital customer experience, ensuring our communications with customers are aligned with current expectations. This includes initiatives such as enhancing our customers' digital interactions with us at the time of connection and disconnection, thereby bringing our service delivery up to industry standard. Mobile alerts would be received so that customers can plan around when work is being completed on their property. It would also enable customers to communicate with us through a chatbot on our website and receive up to date relevant information on their gas services.

Similar to the program we are rolling out in Victoria, we are considering installing digital meters at inaccessible and unsafe properties, significantly reducing estimated reads and bills. We are obligated to read meters every 12 months in South Australia, however there are a number of properties where this is not possible due to safety or accessibility issues. Also, while not included in our net capex, we propose offering an opt-in, fee for service, remote reading solution to empower customers to choose whether meter readers can access their property or where they may not be at a locked property for extended periods.

9.4.2 Forecasting efficient costs

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

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

- unit rate categories, 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, 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 – to new estates, existing homes, commercial and industrial customers;
  - Services – to new homes, multi-user sites, existing homes, commercial and industrial customers; and
  - Meters – new domestic, commercial and industrial meters.
- Meter Replacement – periodic meter change (PMC) – covers domestic, commercial and industrial time expired meter replacement; and
- Mains Replacement – in line camera inspection and reinforcement of AGN's oldest high-density polyethylene (HDPE) mains, replacement of high pressure small diameter steel mains and renewal of older multi-user services.

In this Draft Plan, unit rates are based on a range of information sources including:

- current actual rates or weighted average of historical rates (i.e. over the last three years of the current AA period) achieved for similar work;
- current tendered rates; or
- internal and external specialist engineering estimates.

Tender rates for the new mains and services contracts (incorporating new estates, existing homes, multi-user sites and I&C customers) are scheduled to be received around April 2025.

While we have endeavoured to reflect the best estimate possible in the circumstances, several factors are expected to place upward pressure on unit rates for growth capex activities over the next AA period including:

- higher contractor costs driven by prevailing cost trends and the balance of supply and demand for labour in South Australia's utilities industry;
- suppliers ceasing to offer the service of refurbishing domestic meters; and
- regulatory changes requiring contractors to shift from inhouse traffic management to third-party traffic service providers, with cost projections adjusted to account for the associated additional expenditure.

The unit rates for growth capex will be updated once the new contracts become available for the Final Plan submission, incorporating the results of the April 2025 tender.

The non-unit rate categories include augmentation, IT, 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 internal/external specialist engineering estimates.

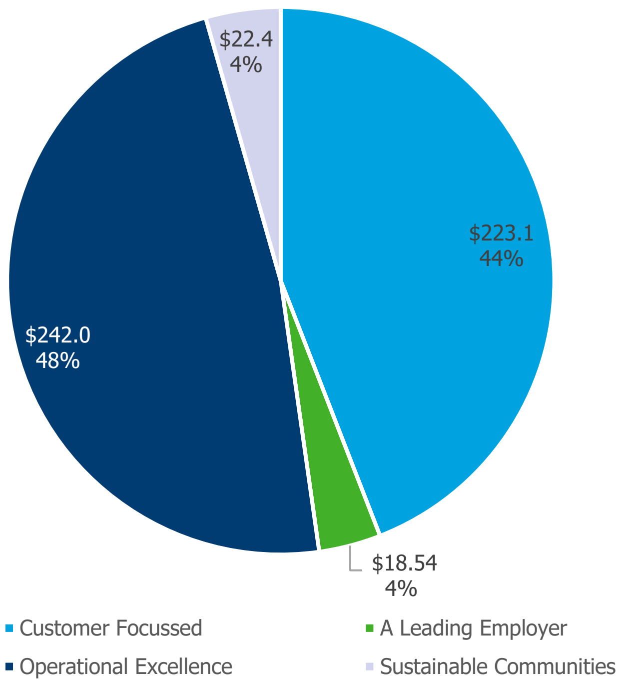
9.5 Capex alignment with our strategic vision in the next AA period

Our capex program aligns with our corporate strategic pillars, which are listed below:

- Customer focussed;
- Operational excellence;
- A leading employer; and
- Sustainable communities.

As shown in Figure 9.3, 48% of our forecasted capex is dedicated to achieving operational excellence, ensuring the capital programs are delivered safely, reliably, on time and to the highest quality standards. Additionally, 44% of our capex is driven by our commitment to being customer focussed, which enables us to provide the services our customers require and value.

Figure 9.3: Next AA capex forecast by AGIG vision and strategic pillars ($million, 2025/26)



9.5.1 Operational excellence

In the next AA period, we propose investing $242 million in targeted projects and programs to sustain our high standards of public safety and operational reliability.

Our investments will focus on critical asset integrity and risk mitigation initiatives, including ongoing integrity dig-ups and modifications to our high-pressure transmission mains to enable In-Line Inspection (ILI). We will replace ageing regulators, valves, telemetry and cathodic protection equipment while also implementing measures to minimise overpressure risks at District Regulating Stations (DRS).

Following the completion of our highest risk (Priority 1) Multi-User Service (MUS) renewals, we will proceed with the medium risk (Priority 2) MUS renewals to further enhance network integrity and reliability.

Additionally, we will invest in the ongoing maintenance and strategic upgrades of our core IT business systems to ensure they remain up to date, fit-for-purpose, resilient to cyber threats and continue to support our business operations efficiently.

9.5.2 Customer focussed

Customers are at the centre of our capex planning. We propose to invest $223 million in the next AA period on projects and programs that will meet customer needs and sustain our strong track record of customer service.

A significant portion of this investment will support network connections, including laying reticulation mains and services, and installing meters to connect around 31,000 new residential and commercial customers. This ensures our network remains capable of meeting evolving customer requirements while maintaining high service standards.

We will also augment our network in both the north and the south extremities of the network to accommodate sustained growth in these areas, safeguarding service levels for both existing and new customers.

To uphold our commitment to our customers, we propose investing $43 million in our meter replacement program which will systematically replace ageing meters to ensure the accuracy of customer billing is maintained.

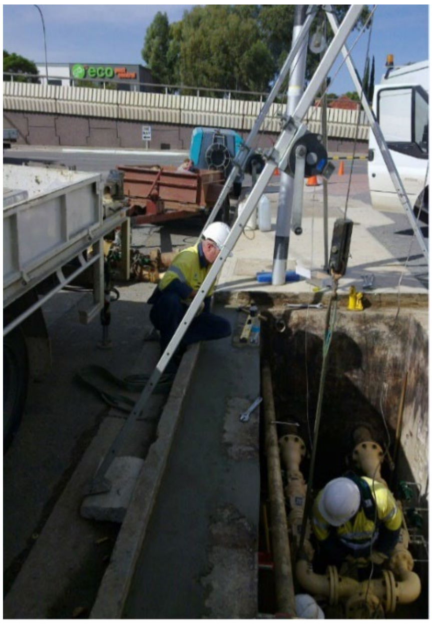
Additionally, we will modernise IT systems that support our customers' digital experience, including improved information for customers when they connect or disconnect from the network and insights into their gas bill.

9.5.3 A leading employer

We plan to invest $18 million in projects and programs in accordance with our vision to be a leading employer. We will replace ageing vehicles and obsolete plant and equipment in the next AA period. Our vehicles and equipment undergo regular maintenance and are replaced based on age, usage and condition to minimise potential risks to employees and ensure a safer, more reliable and efficient work environment.

We propose upgrading our Maximo software with mobility support, proving employees with access to data, reducing manual tasks and streamlining workflows. This will make work easier, improve coordination between teams, and enhance overall efficiency and job satisfaction.

Figure 9.4: Confined space work rebuilding a Distribution Regulator Station



9.5.4 Sustainable communities

We will continue with our mains replacement program, focussing on a more targeted initiative to replace protected steel mains. This program falls under our sustainable communities strategic pillar because, in addition to increasing network safety, it will help reduce emissions by lowering unaccounted for gas (UAFG) on the network.

9.6 Capex drivers in the next AA period

The following sections provide further detail on the drivers of the 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. Our business cases assess the options considered to address the identified issue, the estimated cost of each option, the untreated and residual risk for each option, and alignment with both our vision and the capex requirements of the NGR.

Individual business cases will form part of our Final Plan submitted to the AER by 1 July 2025.

9.6.1 Mains replacement

We are pleased to report that by the end of the current AA period, we will have removed all the cast iron, unprotected steel and other identified highest risk low and medium pressure mains from our network. The mains and services replacement program has now spanned more than three decades.

After reaching this significant milestone, the program will continue as a small scale targeted, proactive replacement program.

As a result, expenditure on mains and services replacement will reduce by $130 million (63%) from $207 million to $77 million in the next AA period.

In the next AA period, we will invest $77 million to:

- proactively replace 11.7 km of protected steel mains located in high density and key risk areas and inspect fifty protected steel mains locations to monitor condition and performance;
- reactively replace approximately 2.5 km of protected steel mains (based on historical failure rates);
- conduct 105 kilometres of inline camera inspections and reinforcement of HDPE 575 mains including samples of vintage HDPE mains and clamps for laboratory testing;
- continue our current program to replace Priority 2 MUS, with the MUS program on track to replace 457 high risk sites in the current AA period and forecast to replace 960 sites in the next AA period; and
- reactively replace approximately 2,450 services due to failure, damage or non-compliance (based on historical failure rates).

9.6.2 Meter replacement

Gas meters measure the volume of gas delivered to a home or business, which helps calculate the customer's gas bill. We undertake periodic meter changes to replace old meters to ensure meter accuracy is maintained.

Based on the age and performance of our current fleet of meters and the metering accuracy requirements we must adhere to, we need to replace more than 115,000 meters over the next AA period at a total cost of $43 million. This is an increase on the estimated 85,000 periodic meter changes to be completed in the current AA period at a forecast cost of $23 million.

The increase relative to the current AA period reflects:

- considerably lower than normal volumes in the current AA period due to a change to meter life, with the implementation of AS4944. This resulted in a 3-year period of reduced meter changes in the current AA period;
- a forecast amount of $4 million in the next AA period to install digital meters to enhance metering performance and efficiency, as well as for installation in unsafe or inaccessible properties to ensure compliance with our obligation to read meters every 12 months; and
- higher meter costs, with suppliers ceasing to offer

lower cost refurbished meters during the current AA period, with the full impact of this change to be felt in the next AA period.

We have used a consistent forecasting approach to determine the number of periodic meter changes required. While the meter change volumes in the 2026-2031 AA period have increased relative the current AA period, they are 30,000 lower than the 2011-2016 AA period.

9.6.3 Augmentation

Augmentation supports the continued growth of the network by ensuring pressure levels are maintained for our customers in areas with high connection growth. We are always monitoring the pressure and performance of our network and are subject to minimum operating pressure requirements.

As the number of connections to our network grows, we can see a reduction in pressure (all other things being equal) as more gas is withdrawn from the network. Network modelling also takes into account less predictable sources of demand such as that from large commercial and industrial users. We use this monitoring data and network modelling to determine areas where our network is becoming constrained and requires augmentation.

We are seeing continuing growth in the north and south of our Adelaide network and consider that two augmentation projects will be required to maintain network pressure within the required range in the next AA period.

In the north of Adelaide we will invest $4 million to extend our network to Angle Vale, a newly established area. The project is after the commissioning of a gate station in Gawler in 2025 which will support continued load growth in the northern area.

In the south we will invest $2 million to augment the Seaford Aldinga high pressure (HP) network, providing increased capacity for the growing southern metro network, without impacting existing customers' supply.

9.6.4 Telemetry

We use a Supervisory Control and Data Acquisition (SCADA) system to monitor and report gas flow, temperature and pressure at critical locations across the network, including City Gate stations, DRS, network fringe points and demand customer sites.

Remote Terminal Units (RTUs) are a key component of the SCADA system, responsible for collecting and encoding network data. In the next AA period, we will invest $4 million to replace ageing and technically obsolete RTUs and other SCADA equipment including data loggers and electronic flow correctors. Additionally, we will continue installing new pressure monitoring equipment to maintain accurate gas flow and pressure data collection as the network expands and evolves, while also ensuring asset integrity.

9.6.5 IT Systems

Our IT systems support several core functions including billing, finance, asset management, operations, regulatory reporting and customer service.

In the next AA period, we plan to invest $88 million in IT. The uplift compared to the current period is largely driven by a significant program to transition and bring inhouse a number of our IT applications during the next AA period.

Our forecast includes:

- continuing our AGIG One IT Strategy initiatives, including strengthening our cyber security capabilities in light of new regulatory and legislative requirements and the evolving cyber threat landscape;
- transitioning a number of our core IT systems in house;;
- upgrading our website and digital platform to optimise customer experience;
- periodic major and minor upgrades and patches to our current suite of software, such as Maximo; and
- renewal of network and end-user devices such as laptops, audio/visual equipment and servers that support critical business functions to ensure they remain current, fit-for-purpose and resilient to security threats.

9.6.6 Growth

We lay new reticulation mains, services and install meters to connect new customers to our network where it is economically and commercially viable.

We will invest $158 million to connect around 31,000 new residential and business customers over the next AA period. This includes new homes and businesses in greenfield and infill developments, as well as existing homes and businesses connecting to our network for the first time.

This includes extensions of our network to new residential developments such as Dry Creek, Golden Grove and Concordia residential estate ($14 million) which are all located in outer northern Adelaide.

We will continue to engage with developers prior to the release of the Final Plan to assess the probability of these developments occurring in the next AA period.

9.6.7 Other distribution system assets

We plan to invest $98 million in other distribution system assets. The largest projects in the upcoming AA period involve:

- continuing modifications to our high-pressure transmission mains to enable in-line inspection (ILI) in accordance with accepted good industry practice ($30 million);
- reducing overpressure risk for DRS facilities ($15 million);
- continued steel pipe integrity management ($15 million) through cathodic protection equipment improvement and end of life replacement, external corrosion direct assessment (ECDA) and casing management; and
- replacing ageing valves ($8 million).

9.6.8 Other non-distribution system assets

We will invest $5 million on other non-distribution system assets during the next AA period. This includes the ongoing procurement and replacement of plant and equipment based on asset age, condition and evolving business needs. Additionally, we will replace trucks and other vehicles once they become unsafe or inefficient to operate and maintain.

We also plan to update our current leak detection system, the Selective Methane Leak Monitoring Approach (SELMA) which is reaching the end of its technical life. Possible replacements include newer technology from a company called Picarro, which produces a vehicle that is driven around distribution mains and conducts leak surveys. Picarro vehicles can detect a wider range of gas emissions than SELMA and measure gases with higher precision. This investment will bring us into line with standard industry practice.

Figure 9.5: Welding on a transmission pipe to install a new valve

9.6.9 Overheads

Overhead costs are operating costs that are not directly attributable to the output of distribution business but are necessary to support operations.

We undertake network planning, technical assurance and engineering activities within our business that contribute to the delivery of our capital program. The costs of these activities and services are capitalised and applied as a capital overhead across the program. In the next AA period, we propose expensing overheads associated with operations and maintenance, and corporate support functions.

On average, 69% of these overhead costs are fixed and 31% are variable, depending on the total size of our capital program. Based on current costs and the projected scale of our capex program in the next period, we propose capitalising $23 million of overhead to capital projects (around 5% of capex), while reclassifying the remaining $33 million in overhead cost as operating expenditure.

9.6.10 Summary of our capex forecast by driver

Figure 9.6 provides a breakdown of our forecast capex by driver for the next AA period. As noted above, growth assets accounted for 31% of total capex, reflecting investment required to support the projected new connection to our network. Mains replacement represents 15% of capex, primarily driven by initiatives to maintain mains and service integrity, including MUS renewal and the proactive and reactive replacement of deteriorated protected steel pipelines.

We forecast that 19% of our capex will be in the other distribution system driver category, which includes corrosion management, replacing SCADA equipment to maintain real time pressure and gas flow monitoring. We will also modify DRS facilities to minimise overpressure risks, ensuring compliance with safety and reliability standards.

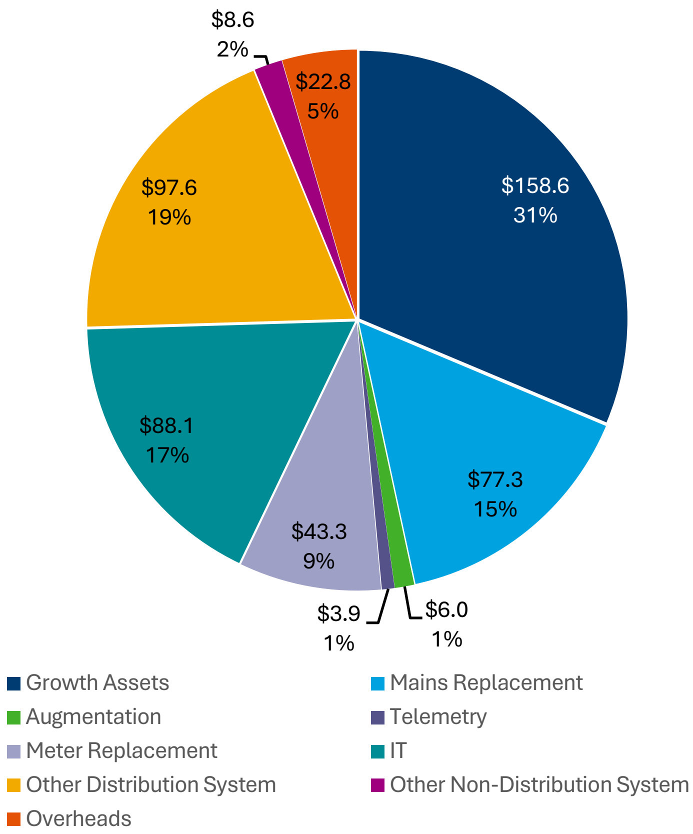
IT investments make up 17% of capex, incorporating transitioning IT systems inhouse, refreshing business software applications and infrastructure, and strengthening cybersecurity capabilities.

The remainder is distributed across projects and programs supporting ongoing strong safety, reliability and service performance.

9.7 How we deliver capex efficiently

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.

Figure 9.6: Capex by driver over the next AA period ($million, 2025/26)



Our operating context is summarised in Figure 9.7

9.7.1 Key Business Plans

We have a number of key business plans that govern the scope, timing and approach to undertaking investment in or upgrade of critical business information systems, asset replacement and augmentation works. These investments 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 objectives. Many of these are endorsed and tracked by the Office of the Technical Regulator (OTR) and the Essential Services Commission of South Australia (ESCOSA).

Our AMS and AMP are key parts of our Asset Management Framework. They outline how our plans are used to drive asset management strategies that are consistent with good industry practice.

Subordinate to the AMS 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

Figure 9.7: Summary of our operating context

Legislation & Frameworks

- National Gas Law
- National Gas Rules
- 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

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

Key Business Plans

- Vision and Strategic Pillars
- Strategic Asset Management Plan
- Asset Management Strategy
- Asset Management Plan
- Risk Management Framework
- Distribution Mains and Services Integrity Plan (DMSIP)
- Meter Replacement Plan
- IT Investment Plan
- Procurement Policy and Procedure

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, reliability and safe operations of the network are maintained.

9.7.2 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, including Executive Leadership 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.

9.8 Alignment with our strategic vision in the current AA period

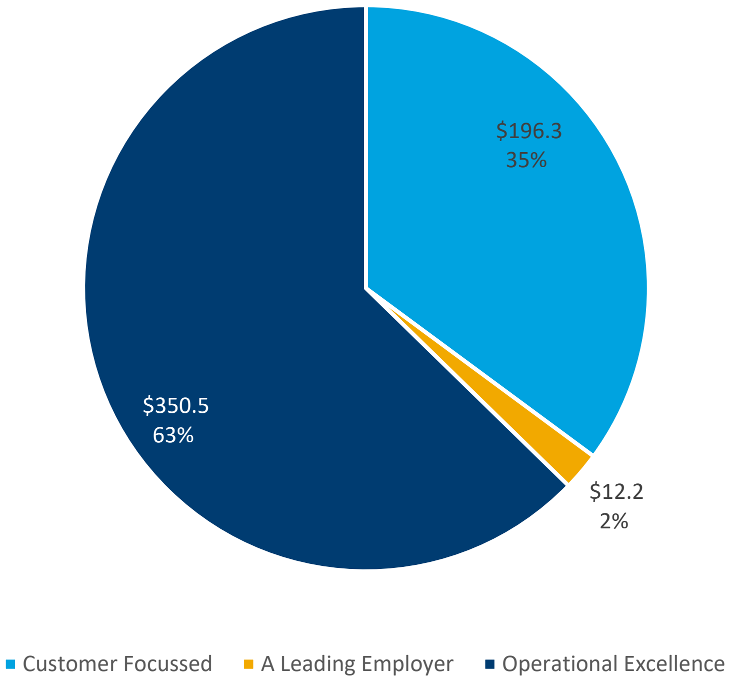
We expect to invest $559 million by the end of this AA period.

Like our capex proposal for the next AA period, our capex in this AA period aligns with AGIG strategic pillars of:

- Operational excellence;
- Customer focussed;
- A leading employer; and
- Sustainable communities.

Figure 9.8 provides a breakdown of the amount of capex we expect to incur against each of these strategic pillars in the current period. As this figure shows, 63% of our capex in the current period is focused on operational excellence and 35% is allocated to customer focussed.

Figure 9.8: Current AA capex forecast by AGIG strategic pillars ($million, 2025/26)



9.8.1 Operational excellence

By the end of the current AA period, we will have invested $351 million on projects and programs that will enable us to maintain operational excellence. We will have replaced over 700km of mains, removing low pressure CI, UPS, first-generation plastic pipes and other identified high risk mains from our network which represents a significant safety milestone for our business. We are also on track to replace all of our highest priority MUS in the current period.

We have undertaken integrity dig ups and surveys, replaced end of

life regulators, valves, telemetry and cathodic protection equipment. We have also updated IT applications including geographic information system (GIS) and mobility integration software. In line with our AGIG One IT Strategy, we have replaced the obsolete SAP Business One with the SAP S/4HANA ERP system, establishing a functional, fully supported, industry-standard system.

9.8.2 Customer focused

We will have invested $196 million in projects that align with our strategic vision of being customer centric. We forecast that we will connect around 37,000 new residential and commercial customers to our network in the current AA period. This investment ensures we continue to meet customer demand while maintaining safe, reliable, and efficient service delivery.

By the end of current AA period, we will have completed the initial phase of planned augmentations in the southern metro network to support residential growth in Seaford and Aldinga. This improves network capacity and ensure the long-term security of supply in these expanding areas. Additionally, we are on track to complete the construction of Gawler Gate Station, a critical infrastructure project designed to increase capacity and strengthen supply reliability across the northern network.

We will invest $23 million to replace approximately 85,000 meters as part of our ongoing meter replacement activities, ensuring precise gas measurement and accurate billing for our customers.

We have successfully launched our customer relationship management (CRM) system, supporting customers experiencing vulnerability, including non-English speakers, individuals with vision impairment and those facing literacy challenges, significantly enhancing our customers' digital customer experience.

9.8.3 A leading employer

We will invest $12 million by the end of the period into the ongoing refresh and replacement of end-user devices, including laptops and mobile phones, office equipment and field devices. This ensures our workforce is equipped with modern, reliable technology, enabling hybrid working arrangements, enhanced staff mobility and greater productivity.

We also will have implemented our Human Capital Management system to deliver a more streamlined and efficient approach to goal setting, performance management and employee training and development. The enhanced system automates compliance tracking, ensuring all employees meet regulatory and safety training requirements. By integrating these critical elements, we are strengthening our commitment to protecting employees and fostering a safe, high-performing work environment for both field and non-field personnel.

9.9 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.

9.9.1 Mains replacement

Our mains replacement program is the largest driver of our capex in the current AA period. It is the single most important activity we can undertake to ensure public safety.

By the end of the current period, we will have removed all the cast iron, unprotected steel and other identified highest risk low and medium pressure mains from our network. This is a significant safety milestone for our business and delivers against the commitments made to the OTR and our customers.

By the end of the current AA period, we will have replaced over 700 km of mains at a forecast cost of $207 million. This includes 494 km of low pressure cast iron and unprotected steel mains and 190 km of HDPE 250 and HDPE 575 mains. Additionally, 20 km of HDPE 575 in Port Pirie will be camera inspected instead of replacement. All mains scheduled for replacement or inspection during the current AA period, as agreed with the OTR, will have been addressed. This volume of activity aligns with our commitment to the AER in our last submission.

Further, we will complete inline camera inspection and reinforcements on 323 km of HDPE 575 DN50 with diameters suitable for this activity. These proactive measures will extend the operational lifespan of these mains by an estimated ten years, enhancing network integrity and long-term asset performance.

9.9.2 Meter Replacement

We will continue our existing periodic meter change program to replace older meters, thereby ensuring meter accuracy is maintained. Based on the age and performance of our current fleet of meters, and the metering accuracy requirements we must adhere to, we have replaced around 45,000 meters to June 2024 and forecast we will have replaced a further 40,000 meters by the end of June 2026 at a total cost of $23 million over the five years.

This forecast is in line with our allowance of $23 million and reflects a slightly lower number of replacements being required offset by higher actual unit rate costs incurred for domestic meter replacements. This higher unit rate was driven largely by our suppliers no longer offering refurbished meters during the current AA period, necessitating the purchase of new meters, which are more expensive than refurbished meters.

9.9.3 Augmentation

We augment our network to prevent pressure deterioration, maintain performance standards and ensure reliable service levels for existing customers in growing areas.

By the end of current AA period, we will complete the installation of a gate station in Gawler and establish a new connection to the SEA Gas transmission pipeline. This project will help maintain minimum distribution pressure in the northern section of our network in a cost-effective and sustainable manner, without adversely affecting existing customers.

9.9.4 Telemetry

At the end of current AA period, we will have invested $2 million to replace obsolete SCADA equipment and upgraded to 4G capable modems. Additionally, we will have installed additional pressure monitoring equipment at strategic locations on the network fringe to enhance our ability to remotely monitor and control the network. These upgrades will ensure the continued reliable collection and transmission of critical operational data, supporting efficient network management as it evolves.

9.9.5 IT System

Our IT systems are fundamental to delivering safe, reliable and efficient services, supporting core business functions such as billing, finance, asset management, operations, regulatory reporting and customer service.

During the current AA period, we will invest approximately $47 million, which expenditure has been focussed on nationalising and consolidating major IT applications, optimising system performance through our application renewal program, strengthening digital capability and undertaking initiatives in line with the AGIG One IT Strategy.

Key programs being carried out over this period include:

- updating our critical IT applications, including our enterprise asset management, GIS, Dial Before You Dig (DBYD) and network mobility systems ensuring they function properly and support safe and efficient network operations;

- completing Stage 1 initiatives of the AGIG One IT Strategy and Roadmap, including enhanced collaboration and communication platforms, enabled economies of scale in operational planning as well as the costs of procuring and supporting IT;
- upgrading outdated and unsupported hardware and network infrastructure to ensure a secure, efficient and fit-for-purpose IT environment; and
- enhancing two-way communication with our customers and uplifting self-service capabilities through the installation of our CRM system and improved website functionality.

9.9.6 Growth

In line with our vision of being customer focused, we will invest $141 million to connect around 37,000 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 footprint (infill) and existing homes and businesses which are connecting to the gas network for the first time.

9.9.7 Other distribution system assets

We will invest around $66 million in other distribution system assets during the current AA period. This investment will support activities such as ongoing surveys and integrity dig ups, renewing corrosion protection assets at the end of their life, modifying high priority transmission pipeline (TP) to allow inline inspections, replacing inoperable valves, installing regulators on the bypass line for I&C meter sets and at DRS to mitigate overpressure risks in the downstream network and prevent customer disruptions.

9.9.8 Other non-distribution system assets

We will invest $6 million on other non-distribution system assets in the current AA period. This investment will cover the replacement of small plant and equipment, vehicles and high-pressure flow stopping equipment, driven by the age and condition of these assets, as well as changing business requirements.

Figure 9.9: Corrosion in a valve pit, North Haven

9.9.9 Summary of our capex in the current AA period by driver

Figure 9.10 provides a breakdown of our capex in this AA period by driver. As noted above, a significant portion of our capex in the current AA period is dedicated to our mains replacement program (37%), reflecting our ongoing commitment to ensuring the reliability and safety of our pipeline infrastructure.

Growth capex accounts for 25% which covers the expansion of mains, services and meters necessary to support new residential, commercial and industrial (I&C) customer connections.

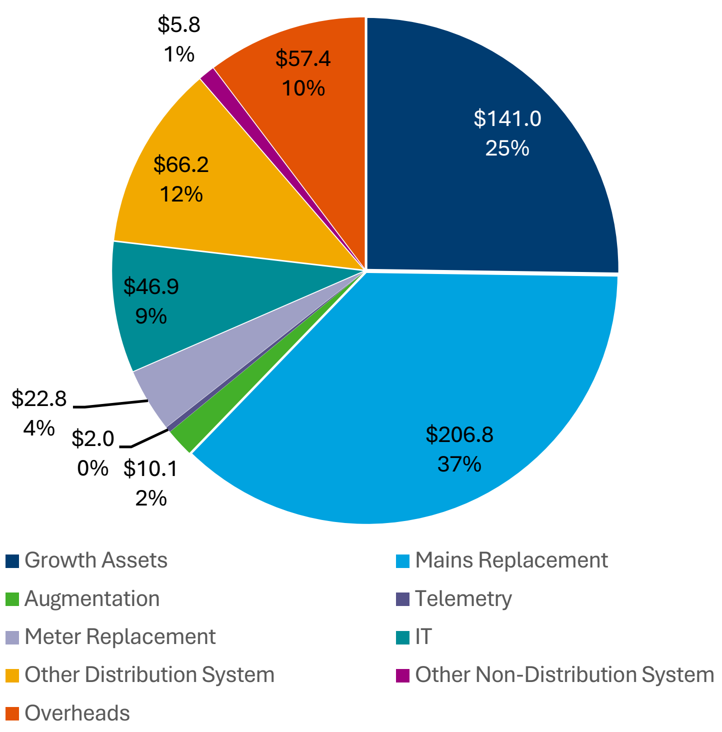
Additionally, 12% of our capex is allocated to other distribution system assets and 9% is an IT investment which are crucial for driving digital transformation and enhancing operational efficiency.

The remaining capex is allocated to various projects and programs aimed at ensuring continued compliance with regulatory requirements while upholding our strong focus on safety, reliability and service performance.

Table 9.2 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 lower than what we expect to incur this period. This reduction is largely due to the completion of the low-pressure mains replacement program in the current AA period.

While mains replacement costs will decline overall, higher forecast unit rates for volume driven activities driven by increased regulatory compliance requirements (primarily

Figure 9.10: Capex by driver in the current AA period ($million, 2025/26)



mandatory traffic control), limited labour market capacity in South Australia and persistent high inflation will erode any volume driven reduction in costs. Additionally, higher IT capex reflects our continued integration into the AGIG One IT environment and the insourcing of our operations.

Distribution system capex will increase due to network modifications to enable ILI and targeted measures to mitigate overpressure risks at DRS, ensuring continued network integrity and safety.

Table 9.2: Forecast capex by driver ($ million, 2025/26)

Driver	Current AA period	Next AA period	Key activities
Growth	141.0	158.6	• Connect new residential and business customers to our network • Extend the distribution network to new areas where it is commercially and economically viable to do so
Mains Replacement	206.8	77.3	• Replace multi-user services (MUS) and protected steel mains • Camera inspections and reinforcement of first-generation HDPE mains
Augmentation	10.1	6.0	• High pressure mains extension in Angle Vale to maintain customer supply pressure while supporting sustained growth • High pressure mains extension and then duplication in the southern metro network
Telemetry	2.0	3.9	• Replacement of end-of-life telemetry equipment • Install additional pressure monitoring equipment
Meter Replacement	22.8	43.3	• Periodic replacement of end-of-life customer meters
IT System	46.9	88.1	• Move to AGIG One IT environment removing duplication across the AGIG group • Maintain existing core business systems • Uplift cyber security and renew IT infrastructure • Deliver an enhanced digital customer service experience
Other distribution system	66.2	97.6	• Corrosion management of steel pipelines • Replace end of life valves, regulators and cathodic protection equipment • Undertake overpressure risk reduction measures for DRS • Modify transmission mains for inline inspection
Other non-distribution system assets	5.8	8.6	• Replacement of small plant and equipment and vehicles
Overheads	57.4	22.8	• Capitalise indirect labour costs for network engineering, technical and compliance services and project & system design
Total	**559.0**	**506.1**	

Australian Gas Networks

9.10 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 commercially and economically viable to do so; and
- enhance the level of customer service that our customers require and expect.

The projects and programs we intend to deliver are described below:

- continuing our current program to replace services at risk Priority 2 MUS sites and reactively renewing services ($50 million);
- replacing protected steel mains ($22 million);
- camera inspections and reinforcing of ageing HDPE 575 mains ($5 million);
- continuing our meter replacement program ($43 million) to ensure accurate gas measurement and billing for our customers;
- augmenting the southern and northern metropolitan networks ($6 million) to maintain required distribution pressures and services to customers;
- replacing end-of-life telemetry equipment and installing additional network monitoring facilities ($4 million) which is critical to operating and monitoring our network;
- ensuring our IT systems are current and fit-for-purpose by maintaining our current applications ($21 million), renewing infrastructure ($7 million), rationalising and integrating the IT environment ($55 million) and implementing new technologies for our business and our customers where there is an overall benefit or service improvement ($3 million);
- connecting over 31,000 new residential and commercial customers to our network ($159 million);
- Modifying our ageing transmission pipelines to allow for inline inspections ($30 million) and other distribution system works such as replacement of valves, over pressure risk reduction, cathodic protection and dig up repairs ($46 million).
- Replacing and refurbishing of small plant equipment and vehicles, and update leak detection equipment ($9 million).

Our proposed capex in the next AA period is significantly lower than both the actual and benchmark set for the current period.

While the mains and services integrity program will continue at a much smaller scale following the completion of low-pressure mains replacement program, the cost of connecting new residential and business customers in greenfield and infill developments is expected to increase due to rising contractor rates and more stringent traffic management requirements.

Questions for consideration

10. Do you have any feedback on the capex activities we have proposed as part of our forecast for the next AA period?
11. Do you support our approach to forecasting capex? Is there sufficient information to understand our proposals and the basis of the costs included?

We are investing more in other distribution system capex and telemetry assets, to enhance steel pipe integrity and corrosion management, continue modifying transmission mains under our ILI initiative, replace ageing valves and regulators, refresh SCADA equipment, and reinforce overpressure protection for DRS.

The uplift in IT investment supports the continued consolidation of IT solutions as part of our AGIG One IT Strategy and the expected insourcing of our operations. This approach minimises operational and cybersecurity risks while achieving economies of scale in IT procurement, support, and operational planning. These strategic investments will uphold the high levels of public safety and reliability our customers value while driving long term cost efficiencies.

10 Capital base

This chapter discusses the movements in our capital base in the current and next AA periods.

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 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 current period will be around $2.0 billion.

10.1 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 we have sold and reflect the reuse of redundant assets in the current AA period.

Our forecast of depreciation is required to be set:

- so that our prices vary over time in a way that promotes the efficient growth of the services provided by our business;
- 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.

10.2 Capital Base as at 1 July 2026

We have adjusted (or rolled-forward) our capital base as at 1 July 2021 with actual capex and inflation and forecast depreciation over the current AA period. We have used forecast information for 2024/25 and 2025/26 as actual information is not yet available.

Table 10.1 shows the adjustments we have made to our capital base over the current AA period. The "funding adjustment" reflects an adjustment for the difference between the forecast and actual capex in the last year of the previous AA period (i.e. 2020/21). Consistent with AER practice, the adjustment reflects the return recovered by AGN that otherwise would have occurred if actual information for 2020/21 were available.

The closing value of the capital base forms the opening capital base for the next AA period.

10.3 Capital Base as at 30 June 2031

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

10.3.1 Capital Expenditure

Our forecast capex was discussed in Chapter 9 of this Draft Plan and is reproduced in Table 10.2, 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 9). 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.

10.3.2 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 10.3).

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 networks.

Table 10.4 shows our forecast straight-line depreciation, which includes the adjusted depreciation.

10.3.3 Inflation

Forecast inflation is a critical element in determining our total revenue and pricing. As explained earlier, forecast inflation is used to adjust the capital base over the next AA period. This forecast is

Table 10.1: Roll Forward of the Capital Base 2021/22 to 2025/26 ($nominal, million)

	2021/22	2022/23	2023/24	2024/25	2025/26
Opening Capital Base	1,702.0	1,762.9	1,901.8	1,965.2	2,002.6
Less Depreciation	90.7	97.1	110.2	110.7	118.0
Plus Conforming Capex	92.1	97.9	96.6	96.9	96.9
Plus Actual Inflation	59.5	138.1	77.1	51.1	74.1
Less 2020/21 Capex Adjustments	-	-	-	-	-11.7
Less Funding Adjustment	-	-	-	-	-4.9
Closing Value	**1,762.9**	**1,901.8**	**1,965.2**	**2,002.6**	**2,039.0**

Note: Totals may not add due to rounding.

Table 10.2: Forecast Capex 2026/27 to 2030/31 ($nominal, million)

	2026/27	2027/28	2028/29	2029/25	2025/26
Mains	23.0	34.4	25.4	30.7	23.2
Inlets	21.0	21.2	20.9	20.1	19.5
Meters	12.7	11.3	11.1	12.9	14.5
Telemetry	0.7	1.3	0.7	0.7	0.7
IT system	18.9	18.4	16.5	17.9	16.4
Other distribution system equipment	36.4	16.9	17.2	17.9	14.8
Other	4.5	1.1	1.1	1.1	1.1
Total	**117.1**	**104.5**	**93.0**	**101.4**	**90.1**

Table 10.3: 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 10.4: Forecast Straight-line Depreciation, 2026/27 to 2030/31 ($nominal, million)

	2026/27	2027/28	2028/29	2029/25	2025/26
Straight-line Depreciation	61.4	70.1	78.4	86.6	88.7

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, which relies on inflation to determine the following two costs:

- Return on capital – which is calculated by multiplying a nominal rate of return (see Chapter 11) 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 10.5) the forecast inflation adjustment applied to the capital base.

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

10.3.4 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.

Table 10.5 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.

Table 10.5: Forecast Regulatory Depreciation, 2026/27 to 2030/31 ($nominal, million)

	2026/27	2027/28	2028/29	2029/25	2025/26
Straight-line Depreciation	61.4	70.1	78.4	86.6	88.7
Less Inflation	55.5	58.6	61.2	63.5	65.9
Regulatory Depreciation	**5.9**	**11.5**	**17.1**	**23.1**	**22.8**

Table 10.6: Forecast Capital Base, 2026/27 to 2030/31 ($nominal, million)

	2026/27	2027/28	2028/29	2029/25	2025/26
Opening Capital Base	2,039.0	2,153.1	2,251.5	2,334.6	2,424.1
Less Depreciation	61.4	70.1	78.4	86.6	88.7
Plus Conforming Capex	120.1	109.9	100.2	112.6	102.6
Plus Actual Inflation	55.5	58.6	61.2	63.5	65.9
Closing Value	**2,153.1**	**2,251.5**	**2,334.6**	**2,424.1**	**2,504.0**

10.4 Summary

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

Question for consideration

12. Do you have any comments on our proposed approach to adjusting capital base over the current and next AA period?

11 Financing costs

Our single largest cost relates to the cost of financing our $2.0 billion investment in the South Australian natural gas distribution network.

IN THIS CHAPTER:

- **We have followed the 2022 AER's Rate of Return Instrument to estimate the rate of return.**
- **Based on forward market estimates, the rate of return is 6.22% (compared to 4.60% in the current period).**

In this Draft Plan, the allowed rate of return and the cost of tax have been calculated according to the AER's Rate of Return Instrument.

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 the business will incur over the next AA period.

11.1 Regulatory Framework

The NGL provides a framework for calculating the return on the projected capital base (rate of return). The AER's Rate of Return Instrument (RoRI) details the approach we are required to follow for calculating the rate of return under the NGL.

The RoRI 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.

We have followed the AER's approach in respect of all aspects of our financing costs and tax allowances.

11.2 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 and are discussed in this section.

11.2.1 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 the Capital Asset Pricing Model, which requires the following three parameters to be estimated:

- The risk free rate – which measures the return an investor would expect from an asset with no risk. It is estimated based on the 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;
- The Market risk premium– which reflects the expected return over the risk-free rate that investors require to invest in a well-diversified

portfolio of risky assets (also assumed to be a 10-year term); and

- Equity beta – which measures the sensitivity of a business' returns relative to movements in the overall market returns (systematic or market risk).

We have applied the AER's 2022 RoRI, which results in a return on equity of 7.72% over the next AA period (see Table 11.1).

These values are indicative and were measured using recent information available prior to the release of this Draft Plan. We intend to use updated information in preparing our Final Plan.

Table 11.1: Indicative return on equity

Parameters		
Equity risk-free rate	4.00%	XX%
Beta	0.6	0.7
Market Risk Premium	6.20%	6.00%
Return on equity	**7.72%**	

11.2.2 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.

Applying the AER's RoRI yields an average return on debt of 5.22%, which we have applied in this Draft Plan.

11.2.3 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 (7.72%) and return on debt (5.22%) results in an overall average rate of return of 6.22% in the next AA period.

11.3 Cost of Tax

We have reflected the outcomes of the AER's December 2018 Tax Review in this Draft 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. These matters are discussed in this section.

The result of following the AER's approach to tax is that our tax building block is zero over the next AA period.

11.3.1 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 14);
- Opex – is a specific building block that is used to determine total revenue (see Chapters 8 and 14);
- 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 portion of the 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.

11.3.2 Value of Imputation Credits

The value of imputation credits (or gamma) is 0.585 as determined in the AER's 2022 RoRI. The effect of gamma is to reduce any tax allowance by 58.5%.

Table 11.2: Roll forward of the tax asset base ($million, nominal)

	2026/27	2027/28	2028/29	2029/30	2030/31
Opening tax asset base	980.0	1,008.8	1,009.0	988.5	972.7
Plus gross capex	120.3	110.3	100.8	112.9	103.1
Less tax depreciation	91.5	110.1	121.2	128.7	134.6
Closing tax asset base	**1,008.8**	**1,009.0**	**988.5**	**972.7**	**941.2**

Note: totals may not add due to rounding

11.3.3 Tax Depreciation

Tax depreciation is used to determine the estimate of taxable income and to update the value of our Tax Asset Base (TAB). Our approach to determining tax depreciation is consistent with that applied in the previous AA and the AER's requirements

11.3.4 Tax Asset Base

The opening TAB of $980 million ($nominal) as at 1 July 2026 has been adjusted for the same forecast information used to adjust our capital base over the next AA period (see Table 11.2).

11.4 Summary

Our financing and tax costs collectively account for around 40% of our total costs. For the purposes of this Draft Plan, we have applied the AER's Rate of Return Guideline and the AER's Tax Review in determining our financing and tax costs.

This results in an average rate of return of 6.22% (see Table 11.3) and a Net Tax Allowance of $0 million.

Table 11.3: Indicative AER Rate of Return

Parameters	AGN Draft Plan
Return on Equity	7.72%
Return on Debt	5.22%
Overall Rate of Return	6.22%
Gamma	0.585

Question for consideration

13. Do you have any comments on our approach to setting the financing and tax costs in this Draft Plan?

12 Incentives

Our incentive schemes ensure that we operate efficiently in respect of both our capital and operating expenditure.

IN THIS CHAPTER:

- **Based on our current AA period opex performance, we have forecast a negative Efficiency Carryover Mechanism (ECM) estimate of $22 million for the next AA period.**
- **At the same time, our forecast capex performance suggests a positive Capital Expenditure Sharing Scheme (CESS) carryover of $23 million**
- **We propose continuation of both schemes in the next AA period.**

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;
- provide balanced incentives between opex and capex so that the most efficient expenditure mix is chosen;
- balance the incentives to pursue efficiencies and to improve or maintain service quality; and
- provide an incentive to invest in innovation in areas that can provide longer-term benefits to customers.

In the current period, the incentive schemes that apply to our South Australian network are the opex Efficiency Carryover Mechanism (ECM) and the Capital Expenditure Sharing Scheme (CESS).

The following sections provide further detail on regulatory requirements for the incentive schemes, our stakeholder consultation to date on our schemes, our forecast scheme carryover outcomes for the next AA period and how we propose to continue the schemes into the next period.

12.1 Regulatory framework

A key objective of the regulatory framework is to promote efficient investment in the operation and use of gas distribution networks.

In keeping with this objective, the NGR provides for gas networks to have one or more incentive schemes applying to encourage the efficient provision of services.

The NGR also requires 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

Australian Gas Networks

- the efficient use of the network.

12.2 Customer and stakeholder engagement

In our reference group meeting in February 2025, we shared our plan to continue the application of the ECM and CESS schemes to our expenditure for our SA network, which have otherwise been supported by stakeholders to date.

We have not received any feedback to suggest any additional incentive schemes, but we invite feedback on the proposed schemes in our Draft Plan.

12.3 Opex ECM

Our South Australian network is currently subject to an opex ECM and we are proposing to continue to employ this incentive scheme in the next AA period.

12.3.1 How the opex ECM works

The opex ECM, which is a key element of our opex forecasting approach (see chapter 8),[1] is designed to provide us with 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 ECM 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 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, this scheme provides for 70% of the efficiency gains (or losses) to be passed through to our customers in the form of higher (lower) prices and we retain the remaining 30%.

12.3.2 Where it is used

An opex ECM or similar is also in place on all other gas and electricity distribution and transmission networks regulated by the AER.

The AER's 2023 review of incentive schemes found that the opex incentives schemes are working as intended with the benefits to consumers up to four times the benefits to network service providers.[2]

Prior to the current AA period, we calculate the scheme has delivered almost $290 million in benefits to our customers since its introduction.

12.3.3 ECM forecast for the current period

We are forecasting an efficiency carryover of negative $22.1 million in the next AA period from the operation of this scheme in the current AA period. The negative carryover is mainly the result of our opex estimate for 2024/25 exceeding the benchmark. This carryover provides a benefit to our customers through our reduced revenue allowance, which offsets the increase in our base year opex.

12.4 Capex CESS

While we have had an opex ECM in place for a long period of time, we have only had an equivalent capex incentive scheme in place for the last AA period.

The CESS mirrors the 'Contingent CESS' that was also adopted by the AER for our Victorian and Albury networks.

The 'Contingent CESS' was introduced in Victoria following an extensive industry engagement program that included stakeholder representatives and gas distributors at a national level, not just Victoria

12.4.1 How the CESS works

In a similar manner to the ECM, the CESS provides us with 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 also:

- reduces inefficient growth in our capital base by providing a greater incentive to incur efficient capex; and
- addresses the imbalance in incentives that currently apply to decisions regarding whether opex or capex should be undertaken.

Under the Contingent CESS, 70% of any incremental capex[3]

[1] Our opex forecasting approach relies on actual incurred opex in the penultimate year of an AA period being efficient.

[2] AER, *Final decision – review of incentive schemes for networks – 28 April 2023*, p 5.

[3] 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.

efficiency gains (or losses)[4] we achieve are passed on to our customers, subject to the following:

- our ability to retain 30% of the efficiency gain would be contingent on us maintaining service standards and the health of the network, which is measured using an Asset Performance Index (API) (see Box 12.1); and
- if we defer capex from one AA period to the next, the efficiency gain would is 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.

12.4.2 Where it is used

As noted above, the AER has allowed a 'Contingent CESS' to be applied to all gas distribution networks in Victoria, South Australia and Jemena's NSW gas distribution network. A form of the CESS also applies to the electricity distribution and transmission networks regulated by the AER.

12.4.3 CESS forecast for the current period

We are forecasting an efficiency carryover of $22.6 million in the next AA period from the operation of this scheme in the current AA period. The combined impact of both the CESS and ECM is for a carryover amount of $0.5 million in our proposed revenue allowance for the next AA period.

Box 12.1: 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.

In our Victorian networks, the AER set targets for each of these measures based on the five-year historical performance of each network. If we meet or exceed these targets, we can retain 30% of the efficiency benefit. If, however, we do not meet these targets, the benefit can be reduced on a sliding scale, potentially to zero (i.e. if we fall below 80% of the target).

12.5 Summary

In the next AA period, we are proposing to continue the application of the ECM and CESS incentive schemes to pursue efficiencies and to continue to share the benefits with our customers.

Questions for consideration

14. Do you support our proposal to maintain the opex efficiency carryover mechanism (ECM)?
15. Do you support our proposal to maintain the capital expenditure sharing scheme (CESS)?

[4] These benefits and costs must be adjusted for any financing benefits or costs.

13 Demand

Our customers' overall demand for gas is expected to decline in the next AA period in line with recent trends.

IN THIS CHAPTER:

- **Our demand forecasts have been independently determined, applying methodologies which were approved previously by the AER, consistent with past trends.**
- **Overall demand for gas in the residential, commercial and industrial sectors is expected to fall, also consistent with past trends.**

The demand for our services drives our operations and is a key determinant of our prices.

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.

Reflecting the differences in the nature of demand for our services, separate demand and customer connection forecasts have been developed by independent expert Core Energy & Resources ('Core Energy'), for our:

- Residential sector;
- Commercial sector (business customers who use less than 10 terajoules of gas each year); and
- Industrial sector (our largest business customers).

These market sectors 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 demand for natural gas for our:

- residential sector to fall by 5.5% per year, in response to a range of external factors, such as higher wholesale gas prices, improved appliance and dwelling efficiency, impacts of policy favouring electrification and negative sentiment towards gas, fewer new connections than recent history and more disconnections from the network;
- commercial sector to fall by 1.0% per year, largely due to higher wholesale gas prices, improved appliance efficiency, electrification, less new connections and more disconnections from the network; and
- industrial s to fall by 2.9% per year, which reflects an accelerating long-term trend in response to higher wholesale gas prices, lower economic activity and increasing efficiency.

Overall, Core Energy projects that the demand for gas by our customers will fall by 3.2% per year in the next AA period, which falls between AEMO's current Progressive and Step Change scenarios for South Australia.

The following sections provide more detail on the relevant regulatory framework, the forecasting method and the demand forecasts themselves.

13.1 Regulatory framework

Our AA proposal must include the forecast demand for reference services. In keeping with the NGR, these forecasts must:

- 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 have assessed Core Energy's forecasts against these principles and concluded that the Core Energy forecasts were consistent with the above principles.

13.2 Customer and Stakeholder engagement

We engaged with stakeholders (including retailers and our customers) in respect of our demand forecasts. At our SA Reference Group meetings and Retailer Reference Group meetings, we discussed the approach and the importance of understanding key drivers of future demand.

Stakeholders indicated they understood our approach to forecasting residential, commercial and industrial demand and noted that the approach is consistent with that adopted for our recent reviews, including our last SA review. Stakeholders were comfortable with the approach to forecasting demand.

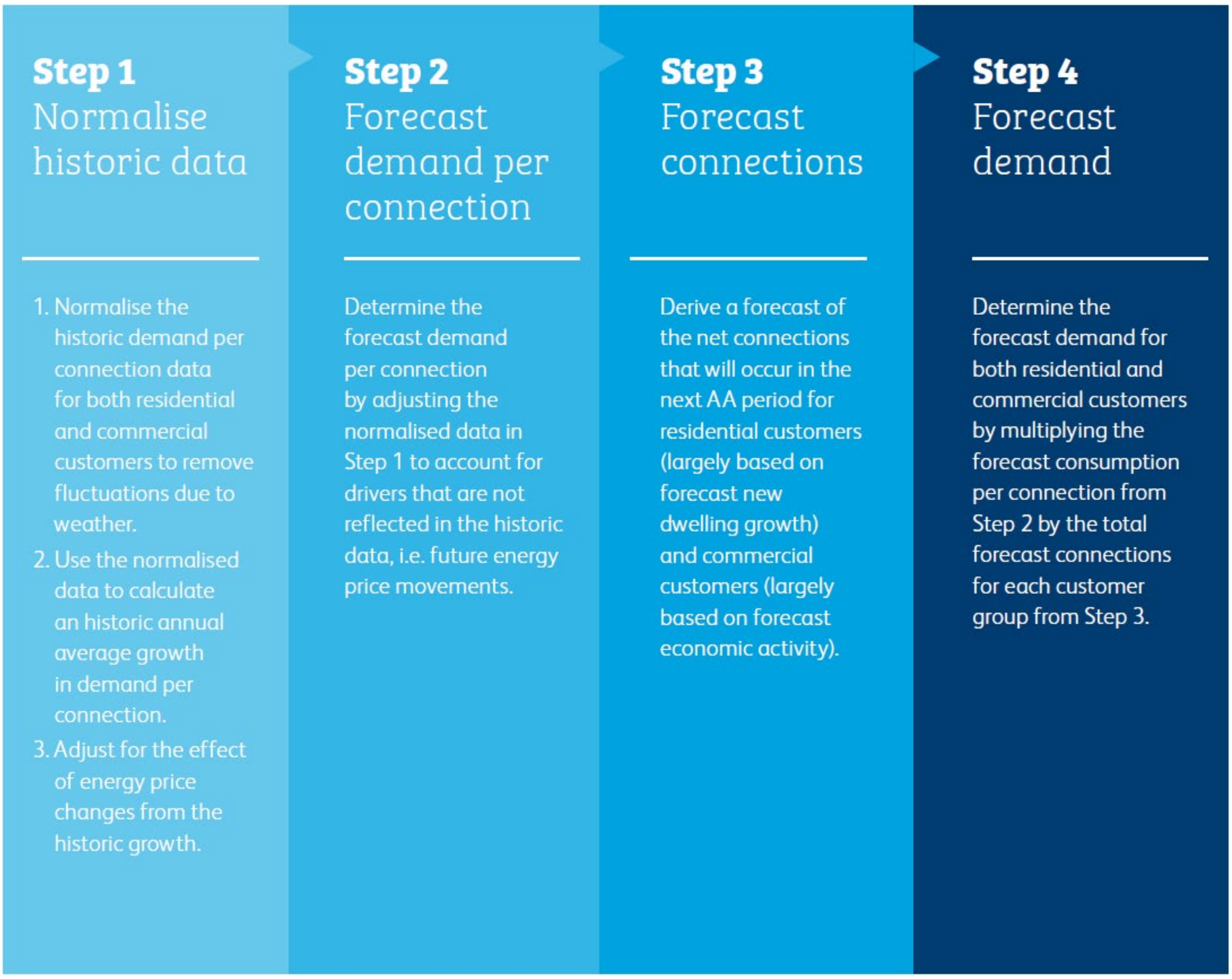
In particular, retailers indicated that trends shown in demand forecasts are consistent with their own observations and expectations of demand.

We will continue to refine our demand forecasts, including conducting a survey with our major SA industrial users to better understand their future demand requirements, including any planned connections or disconnections over the next AA period.

13.3 Residential and Commercial Demand

The method that Core Energy has used to forecast demand and

Figure 13.1: Forecasting method used for residential and commercial customers



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.

13.3.1 How our forecasts were developed

The method Core Energy has used to forecast our residential and commercial customers' demand is summarised in Figure 13.1.

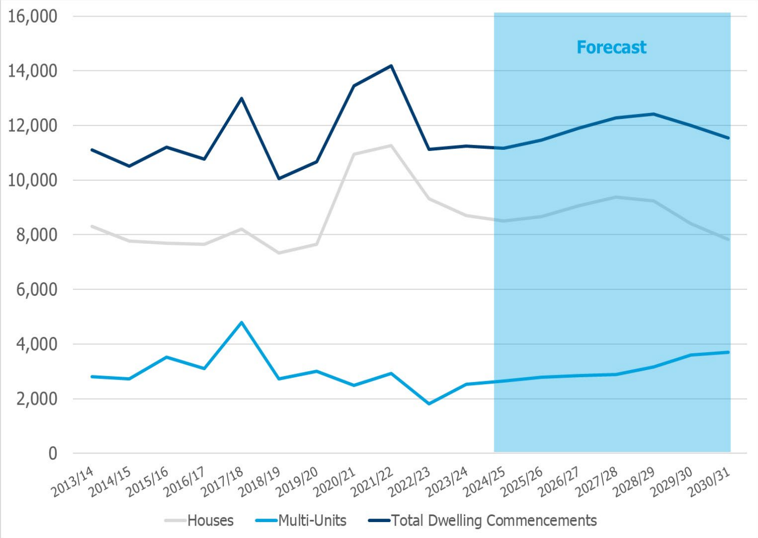
The method depicted in Figure 13.1 is consistent with the approach that was used to develop the demand forecasts for the current AA period for both our South Australian, and Victorian and Albury networks, which were approved by the AER. It is also consistent with the principles employed by the Australian Energy Market Operator (AEMO), when forecasting residential and small commercial demand for its Gas Statement of Opportunities.

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 1.1 in Figure 13.1).

Figure 13.2: HIA actual and forecast dwelling commencements in South Australia



The adjustment Core Energy has made is based on the same approach that is used by AEMO, which is referred to as the Effective Degree Day (EDD312) weather standard. This approach enables us to determine the volume impact attributable to annual variances to weather relative to the EDD baseline.

This volume impact is then removed from the historic consumption per connection trend to derive a weather normalised trend that 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 1.3 in Figure 13.1.

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 -0.30 for residential and -0.35 for commercial customers has been assumed. This implies that a 1% increase in retail gas prices will result in a 0.30% and 0.35% reduction in consumption per connection for residential and commercial customers, respectively.

Cross-price elasticity: a long-term-cross-price elasticity of 0.10 has been assumed (this implies that a 1% increase in retail electricity prices will result in a 0.10% increase in consumption per connection).

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 13.2).

As Figure 13.2 shows, HIA has projected growth in both detached houses and multi-unit dwellings in the first half of the next AA period, after which the number of housing commencements drop steeply, partially offset by more multi-unit dwellings. The peak in commencements was observed during 2021 and 2022 due to the federal government's housing stimulus during that period.

13.3.2 Residential demand forecast

Using the methodology set out above, Core Energy has developed an early forecast of residential demand in the next AA period by multiplying the forecast number of

Figure 13.3: Residential connections (closing) forecast (no.)

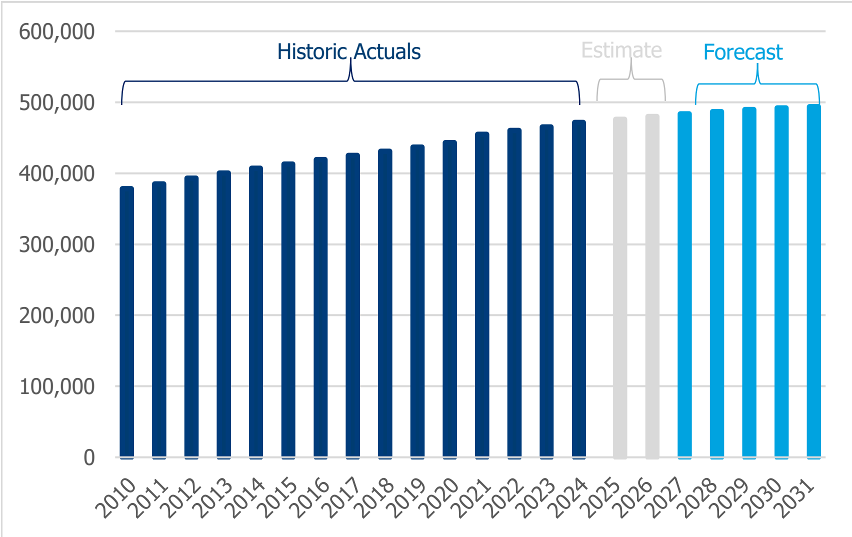


Figure 13.4: Residential consumption per connection forecast (GJ)

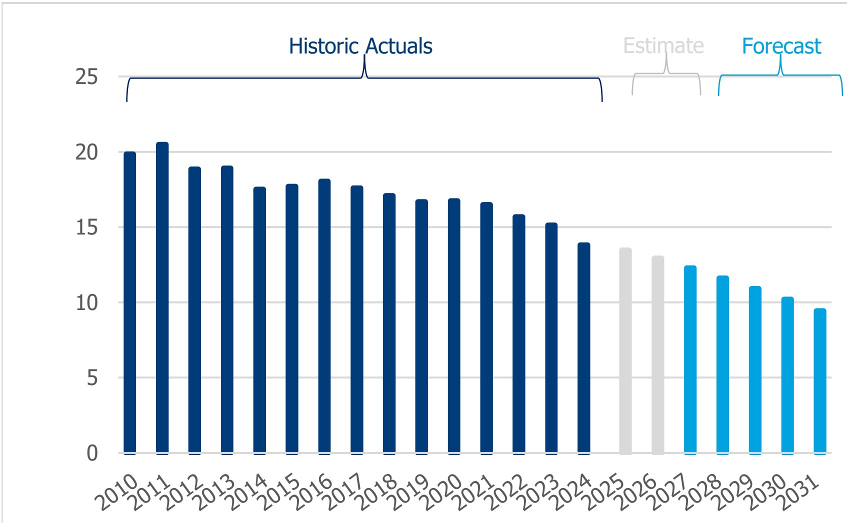
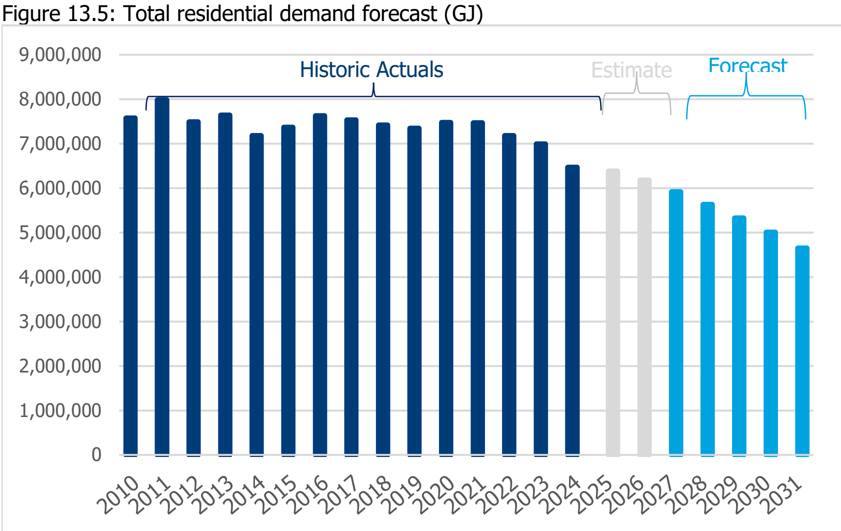


Figure 13.5: Total residential demand forecast (GJ)



J)

residential connections by forecast consumption per connection.

Residential connections

Core Energy is projecting that our residential connections (net of forecast disconnections)[5] will grow by 0.6% per year in the next AA period, reaching 493,747 by the end of the period (see Figure 13.3).

The forecast growth in residential connections is lower than the 10-year historic average growth rate of 1.5% per year. This is due in large part to:

- a drop in new dwellings forecast in the latter half of the next AA period (see Figure 13.2);
- housing stimulus during the pandemic ending;
- a lower penetration rate observed in the last five to seven years, driven by the emergence of all electric developments and cost of living pressures; and
- an increase in the number of disconnections.

Consumption per connection

Core Energy is also forecasting that consumption per residential connection will fall by around 6.1% per year over the next AA period, from 12.9 GJ in 2025/26 to 9.4 GJ in 2030/31.

As Figure 13.4 shows, this fall is consistent with the long-term decline in average residential consumption per connection that has occurred over the past 15 years. In 2008/09, the average consumption per connection was 20.6 GJ, however by 2023/24 it was 13.8 GJ. This decline is also

Figure 13.6: Commercial connections (closing) forecast (no.)

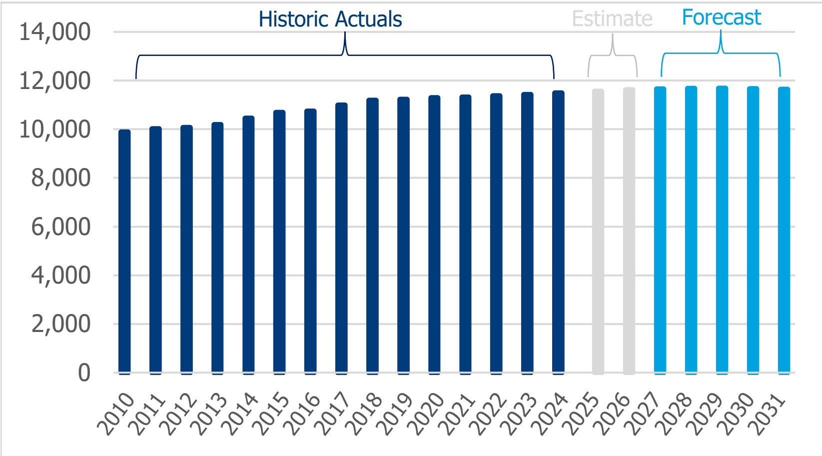


Figure 13.7: Commercial consumption per connection forecast (GJ)

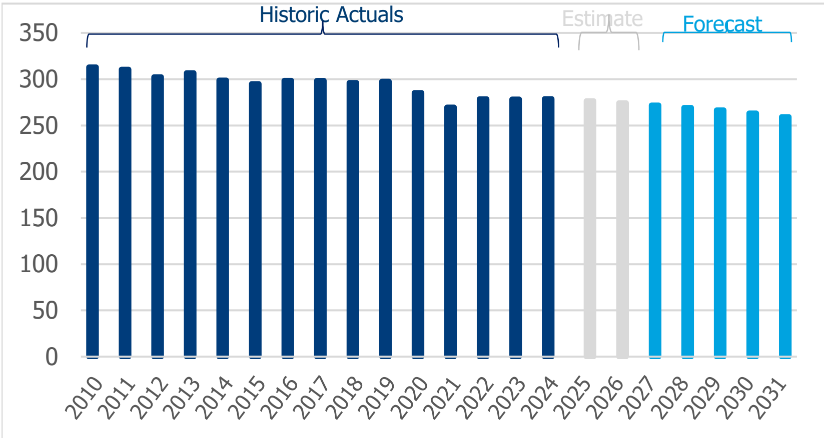
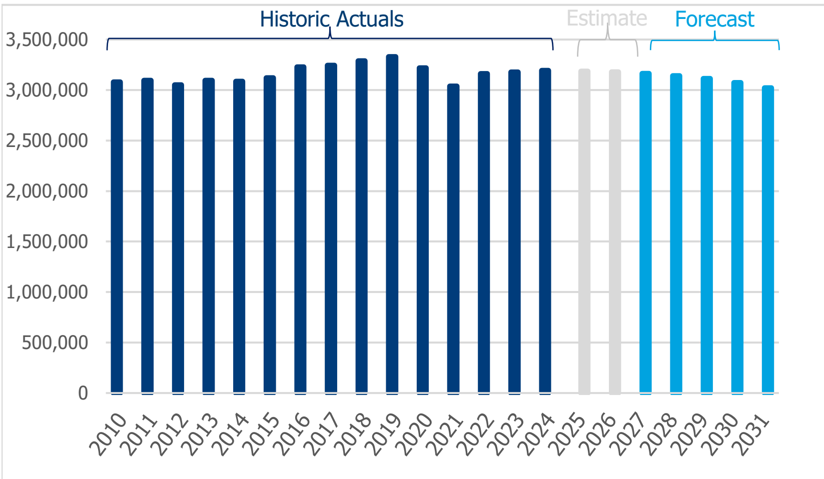


Figure 13.8: Total commercial demand forecast (GJ)



[5] The forecast number of disconnections is based on the 10-year historic disconnection rate to total connections.

being observed in other gas distribution networks.

The key drivers of this decline include:

- improved appliance and dwelling efficiency;
- the substitution of gas appliances for their electric equivalent (for example, substituting gas heating for electric reverse cycle air-conditioning);
- a forecast increase in the construction of multi-unit dwellings which consume far less gas than detached dwellings;
- the expected increase in wholesale gas prices over the period; and
- new connections consuming around 20% less gas on average than historical connections due to lower average dwelling size and appliance efficiency.

Total residential demand

Overall, the demand for gas by our residential customers in the next AA period is expected to fall by 5.5% per year from 5,917TJ in 2025/26 to 4,651TJ in 2030/31 (see Figure 13.5 and Table 13.1).

This fall reflects the effect of the forecast decline in consumption per residential connection which is partially offset by growth in residential connections.

13.3.3 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 0.1% per year reflecting recent trends in new connections and disconnections.

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 leading to higher retail bills, thereby dampening demand (see Figure 13.7).

The decline is not, however, expected to be as pronounced as it is for our residential customers due to the slower historic trend decline in consumption per connection, with consumption per commercial customer forecast to fall by 1.1% per year over the next AA period from 272 GJ in 2026/27 to 259 GJ in 2030/31.

Total Commercial demand

The total demand for gas from commercial customers is expected to decline by 1.0% per year over the next AA period, from 3,163TJ in 2026/27 to 3,021TJ in 2030/31 (see Figure 13.8 and Table 13.1).

13.4 Industrial demand

13.4.1 How our forecast was developed

In contrast to residential and commercial customers, our industrial customers are charged on the basis of the maximum 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 are our industrial customers are expected to consume in a year (referred to as Annual Contract Quantity (ACQ)).

To help inform this forecast, we will conduct a survey of our top industrial customers, the objective of which is to better understand their future MDQ and ACQ requirements, including any planned connections or disconnections over the next AA period.

For those customers that do not respond to the survey, Core Energy will examine the relationship between each customer's historic demand and economic activity. In those cases where there is a statistically significant relationship, the MDQ and ACQ is forecast by applying an adjustment to the historic demand based on forecast economic growth.

In those cases where there was not a statistically significant relationship, the MDQ and ACQ is forecast by applying an adjustment based on the historic trend.

Figure 13.9: Industrial Connections Forecast (no.)

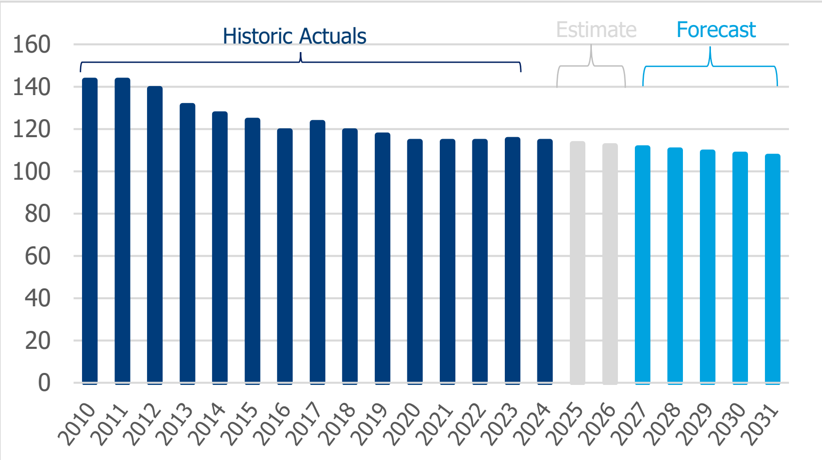
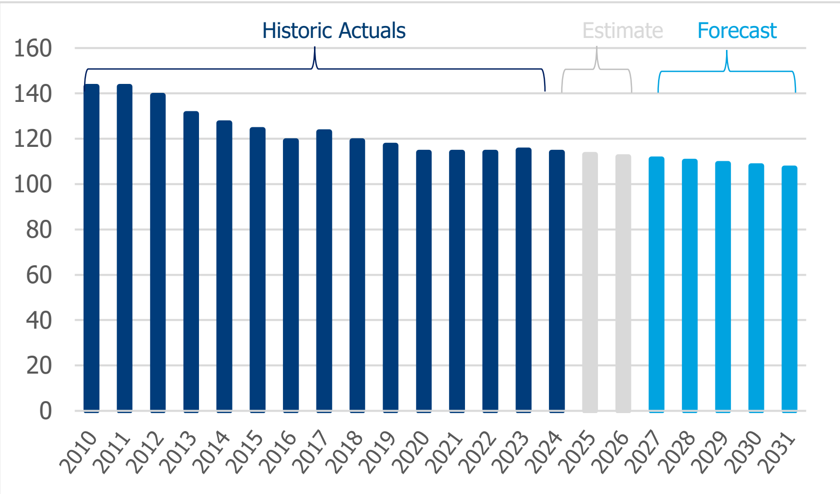


Figure 13.10: Industrial demand – MDQ (GJ)



The connections forecast for industrial customers has been developed having regard to historic growth estimates and information on known new connections and disconnections.

13.4.2 Industrial demand forecast

Industrial MDQ is forecast to decline by 2.9% per year to 35,940 GJ MDQ over the next AA period (see Figure 13.10). Industrial connections are also forecast to decline to 107 connections, from 112 at the start of the AA period.

13.5 Summary

Table 13.1 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 & Albury networks.

Questions for consideration

16. Do you support our approach to forecasting demand?
17. Are there other factors we should consider in developing our demand forecasts?

Table 13.1: Summary of demand forecast

	2026/27	2027/28	2028/29	2029/30	2030/31
Residential demand					
Connections (closing)	483,668	486,806	489,715	492,023	493,747
Consumption per connection (GJ)	12.3	11.6	10.9	10.2	9.4
Demand (TJ)	5,917	5,632	5,327	5,007	4,651
Commercial demand					
Connections (closing)	11,655	11,677	11,684	11,664	11,641
Consumption per connection (GJ)	271.8	269.3	266.6	263.2	259.3
Demand (TJ)	3,163	3,141	3,114	3,073	3,021
Industrial demand					
Connections (closing)	111	110	109	108	107
MDQ (TJ)	40,455	39,312	38,180	37,059	35,940
ACQ (TJ)	9,185	8,959	8,727	8,491	8,249

14 Revenue and prices

This section sets out the total revenue, proposed prices and changes to the existing tariff variation mechanism to apply over the next AA period.

IN THIS CHAPTER:

- **We have proposed to cut South Australian network prices by 3.5% on 1 July 2026 followed by an increase of 1.5% each year thereafter in real terms. This equates to an upfront nominal price cut of 0.9%.**
- **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 also considering adjustments to our tariff variation mechanism (including related to the price cap mechanism) and our tariff structure, to meet the AER's requirements, while maintaining price stability for our customers.**

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 retailers for providing reference services.

14.1 Regulatory Framework

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 a forecast of the cost of tax.

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 Carryover Mechanism - ECM) and capex incentive mechanism (Capital Expenditure Sharing Scheme – CESS) which apply 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.

14.2 Customer and stakeholder engagement

Customers and stakeholders told us that affordability is their highest priority. They have also indicated that price stability is also important to them. In developing this Draft Plan, we have carefully considered the impact individual aspects of the plan will have on price.

As part of our engagement on this Draft Plan, we will also seek feedback on:

- our proposed price path,

- our proposed pricing structure, specifically in relation to the mix of fixed and variable components of our prices, and
- elements of the tariff variation mechanism, including a proposed hybrid (price/revenue cap) mechanism and other cost pass through events.

This feedback will be reflected in our Final Plan submitted to the AER by 1 July 2025.

14.3 Revenue

This Draft 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 14.1.

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. 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 revenue and percentage changes in prices are set out in Table 14.2. We have developed our price path in order to:

- provide for revenue growth that approximates the growth in the capital base over the next AA period to ensure the growth in our revenue is commensurate with changes in our underlying costs; and
- to equate revenue (or building block revenue) with our underlying costs recovered through the prices we charge retailers in 2030/31 (the last year of the next AA period) to ensure that the one-off adjustment to prices (either positive or negative) required from 1 July 2031 to equate smoothed revenue with costs is minimised.

Table 14.1: Building Block Total Revenue, 2026/27 to 2030/31 ($nominal, million)

	2026/27	2027/28	2028/29	2029/30	2030/31
Return on Capital	122.1	130.6	139.2	147.5	158.8
Return of Capital	5.9	11.5	17.1	23.1	22.8
Opex	90.7	94.8	109.6	113.6	113.7
Incentive Mechanism	4.9	-2.7	-1.3	-1.4	5.2
Cost of Tax	-	-	-	-	-
Building Block Total Revenue (including ARS)	**223.7**	**234.2**	**264.6**	**282.7**	**300.5**
Less ARS	2.3	2.4	2.5	2.6	2.7
Building Block Total Revenue (excluding ARS)	**221.3**	**231.7**	**262.1**	**280.1**	**297.8**

Note: Totals may not add due to rounding

Table 14.2: Proposed Price Path, 2026/27 to 2030/31 ($nominal, million)

	2026/27	2027/28	2028/29	2029/30	2030/31
Building Block Total Revenue (excluding ARS)	221.3	231.7	262.1	280.1	297.8
Smoothed Revenue	251.4	254.8	257.4	259.1	259.3
Real Price Path	3.51%	-1.50%	-1.50%	-1.50%	-1.50%

By aligning our price path to the growth in our capital base we are more likely to sustain stable 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 (see Section 14.3.1).

As demand is forecast to decline over the next AA period, there is a large variance between forecast building block and smoothed tariff revenue in 2030/31 which builds in a natural price increase for the following AA period. We have partially addressed this with the small price rises in years two to five of the next AA period, however we have kept the size of these price rises to a minimum to minimise the impact on customers.

14.4 Prices

As already noted, we recover our revenue through the prices that we charge retailers for providing reference services.

In the next AA period, we are proposing to cut South Australian network prices by 3.5% on 1 July 2026 followed by increases of 1.5% each year thereafter, in real terms. This equates to an upfront nominal price cut of 0.9%, which will reduce the average annual bill by:

- $6 for residential customers,
- $60 for commercial customers, and
- $2,800 for industrial customers.

The following sections outline our current and proposed pricing structures for our customer segments, which would determine charging for different levels of consumption. It also covers the weighted average price cap mechanism and our proposed new form of revenue control which combines elements of a price cap and revenue cap as a hybrid mechanism, into the next AA period.

Both matters have already been consulted upon with our customers and stakeholders through our Reference Service Proposal. However, in response to this proposal and our stakeholder feedback received, the AER has asked us to review our proposal further, in consultation with our stakeholders. The AER has indicated that it is seeking to disincentivise gas network growth and higher gas consumption, for better alignment with the emission reduction target aspect of the NGO.

Importantly however, network tariffs should be structured to provide service providers with the greatest opportunity to recover their efficient costs.

With this in mind, we note that, in any event, gas retailers have ultimate control of the overall price and structure of their offering to our customers and generally do not reflect the gas distributors tariffs. Further, energy retailers are heavily promoting residential electrification which also significantly nullifies any perceived incentive created by declining block network tariffs.

In our view, efficient pricing remains at the core of the NGO, NGL and NGR, the primary objective of each is to deliver efficient prices in the long-term interest of consumers.

14.5 Pricing structure

14.5.1 Current pricing structure

Our current pricing structure includes two zones, South Australia (excluding Tanunda) and Tanunda.

The South Australia (excluding Tanunda) zone includes residential, commercial and industrial customers whilst the Tanunda zone includes only residential and commercial customers.

Prices for residential and commercial customers consist of a number of volumetric (or consumption) based charging parameters (in dollars per GJ per day) and a fixed supply charge (in dollars per day).

We currently recover approximately 75% of our revenue in the residential and commercial segments in the variable (volumetric) components of our tariffs and 25% through the fixed components.

Our current variable pricing for residential and commercial customers involves higher prices for lower usage blocks and lower prices for higher usage blocks.

For example, the 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.

Prices for our industrial customers are capacity based and consist of banded charging parameters (in dollars per GJ of MDQ) (see Table 14.4). All prices decline as usage increases to promote better network utilisation.

Benefits of the current pricing structure

Our current declining block tariffs represent a form of efficient non-linear pricing. That is, by charging a lower price for higher volume gas distribution, we ensure that demand is not zero, and so we can spread our fixed costs over more demand. Removing declining block tariffs would remove the ability to obtain these types of efficiency gains for our customers.

Further, as gas demand is greatly influenced by weather, the current structure ensures more stable revenue and prices despite volatility in weather form year to year.

We consider our pricing structures align with our obligations that require AGN to promote the efficient use of the network.

Smoothing bills through the year

Our tariff bands are structured such that most of space heating demand occurs in the highest (lowest-priced) band for many of our customers. Therefore, our tariff structure also has the practical effect of smoothing bills through the year, making them higher in summer than they would be under a flat or inclining block tariff and lower in winter.

14.5.2 Customer and stakeholder feedback on our pricing structure

In our RSP, we consulted on our tariff structure. We found that most of our customers and stakeholders supported continuation of the declining block tariff, acknowledging its benefits and the unacceptable bill impacts for higher usage customers that would result from a shift to a flat structure.

The stakeholder who indicated some support for flatter tariffs also stated that this should only be proposed if there are government subsidies or equivalent in place to offset the negative bill impact on customers. No such government policy or scheme currently exists.

14.5.3 AER's request for further consideration of flat tariffs

In response to our RSP, the AER has requested that we consult further on options for flattening of the tariff structure, with consideration of bill impacts for customers.

The AER suggested that flattening over two AA periods might be appropriate if a single period move to flat tariffs is not reasonable given bill impacts for customers.

Our assessment of the approach to flatten tariffs over two periods has found that the impact on our customers would still be unacceptable and not in our customers long term interests. Table 14.3 shows these impacts for residential customers (as option 1), including annual bill increases of

- $161-plus for around 63,000 residential customers who use at least 30 GJ per year.
- $471-plus for more than 10,000 customers who use at least 60 GJ per year.

Even if these increases occurred incrementally over the period, higher usage customers would still be paying the higher bills every year thereafter, and further changes would only incrementally increase their bills even further.

It is not reasonable to expect customers to forgo an essential service or simply switch appliances (to avoid the higher charges), especially if the appliances are nowhere near the end of their useful lives.

Further, our RSP found that the potential emission reduction benefits pale in comparison to these negative impacts (e.g., our modelled emission reduction benefits would be equivalent to just 0.02% to 0.04% of the average annual bill).

Therefore, we have not adopted the AER's suggested change to our tariff structure.

14.5.4 Other potential pricing structures

We have considered other options towards 'flattening' our tariffs which have lower customer bill impacts.

An option we are considering includes increasing our fixed or base charge for our residential and commercial customers (eg, by up to 10% or 20%).

This change would reduce the extent of gas consumption exposed to variable usage rates, which should be consistent with emission reduction objectives, as contended by the AER.

An example of the bill impacts from these types of changes for our residential and commercial customers are in Tables 14.3 and 14.4 respectively, indicated as option 2 in both cases.

These options incorporate the rebalancing of the other variable usage tiers with some flattening of higher usage tiers. Changing the tariff structure in this way can be an effective way to minimise negative bill impacts on our customers and ensure that they continue to have the stable and affordable prices they need and value.

At this stage, we welcome further feedback on these options for proposed tariff structure changes.

Table 14.3: Modelled residential bill impacts from changes in tariff structure, 2026/27 to 2030/31 ($ nominal)

Annual GJ	Annual bill under current tariffs	Annual bill under 'halfway to flat tariffs' (1)	Difference from current tariffs (1)	Annual bill with 'increase in fixed charge and rebalancing across variable usage blocks' (2)	Difference from current tariffs (2)
5	$284	$261	-$23	$296	+$12
10	$451	$405	-$46	$451	$0
15	$507	$494	-$13	$505	-$2
20	$488	$546	+$58	$487	-$1
25	$506	$616	+$109	$505	-$1
30	$525	$686	+$161	$523	-$2
45	$579	$895	+$316	$576	-$3
60	$634	$1,105	+$471	$630	-$5
100	$781	$1,665	+$884	$772	-$9
200	$1,146	$3,064	+$1,918	$1,127	-$19

Table 14.4: Modelled commercial bill impacts from changes in tariff structure, 2026/27 to 2030/31 ($ nominal)

Annual GJ	Annual bill under current tariffs	Annual bill under 'halfway to flat tariffs' (1)	Difference from current tariffs (1)	Annual bill with 'increase in fixed charge and rebalancing across variable usage blocks' (2)	Difference from current tariffs (2)
15	$408	$405	-$3	$431	+$24
45	$732	$723	-$9	$754	+$22
100	$1,326	$1,306	-$20	$1,345	+$19
200	$2,406	$2,367	-$39	$2,420	+$13
300	$3,487	$3,428	-$59	$3,494	+$8
1,000	$8,116	$9,598	+$1,482	$8,070	-$47
3,000	$15,750	$24,489	+$8,739	$15,414	-$336
5,000	$21,221	$38,955	+$17,733	$20,508	-$714
8,000	$27,663	$58,129	+$30,467	$25,941	-$1,722

14.6 Form of revenue control

14.6.1 Current price cap

The current price cap control places a constraint on the overall average movement in tariffs from one year to the next (referred to as a weighted average price cap (WACP)). The constraint allows average prices to change by the annual change in the Consumer Price Index (CPI) less the X-factor[6]. Under a price cap, the business is exposed to volume risk – that is, any variation in volume and subsequent revenue impact is borne by the business. This significantly reduces price volatility for customers within an AA period.

In addition, the economic rationale for the price-cap form of control is to provide a financial incentive for regulated businesses to rebalance prices among their service offerings towards a form that is more allocatively efficient.[7]

14.6.2 Customer and stakeholder feedback on our price cap

We engaged with our customers on the matter of our price cap and alternatives such as a revenue cap.

Under the revenue-cap form of control, tariffs are set such that only the building block revenue determined by the AER is recovered over the AA period. Therefore, any annual difference in revenue between the actual and the approved allowance will be passed through to customers - via lower tariffs if actual revenue is higher than the allowance, and higher tariffs if actual revenue is lower than the allowance. For this reason, the tariffs can change in real terms from year to year under this approach, depending on demand outcomes.

Therefore, a shift from a price cap to a revenue cap would shift volume risk to our customers and could lead to considerable price volatility during the regulatory period, particularly given the variance in weather from year to year and the subsequent volatility in volume of gas delivered through the network.

During our RSP engagement process, our customers and stakeholders indicated to us that they prefer price stability and predictability and that shifting more volatility onto customers within a regulatory period is not desirable.

14.6.3 Other proposed changes to the price variation mechanism

We will be allowed to vary our prices over the next AA period in accordance with procedures approved in our AA Document (referred to as approved price or tariff variation mechanisms).

In addition to the hybrid price mechanism discussed in the previous section, our Draft Plan proposes further changes to the tariff variation mechanism in the next AA period for two additional cost pass through events.

Our proposed two additional cost pass through events are consistent with those in our Victorian distribution network AAs, to account for:

- the cost of meeting the Safeguard Mechanism obligations for the network, and
- a true up of potentially unrecovered abolishment costs.

More information will be provided in our Final Plan about these events and the likelihood of any cost pass through occurring in the next AA period.

14.6.4 AER request for further consideration of a hybrid mechanism

In response to our RSP, the AER has requested that we consider a hybrid mechanism which combined elements of the weighted average price cap approach and revenue cap.

The AER cited the approach recently proposed by Jemena (for its 2025-30 NSW gas distribution network AA) as an "acceptable approach." The Jemena proposal was for a 'cap and collar' approach whereby a price cap applies up to a threshold of 5% for annual revenue variation (from forecast) and beyond this level, there is a 50:50 sharing of the incremental revenue gains or losses between customers and the business.

[6] In the case of AGN South Australia, there is also an adjustment factor reflecting the movement in the annual price of unaccounted for gas.

[7] See proof in Laffont, J and J Tirole /(2001), *Competition in Telecommunications*, MIT Press, pp.66-67 (as advised by Incenta Economic Consulting in our submission to the A

14.6.5 Our proposed mechanism

We maintain that the most suitable approach for our customers is the price cap form of regulation. The uncertainty presented by the energy transition only strengthens the case for this type of approach, ensuring more price stability when there might be sudden demand shifts.

We have considered the application of the Jemena proposal for a hybrid mechanism to our South Australian network. However, we consider that this approach is not the most suitable as it can place too much burden on our customers during times of lower demand such that higher prices would be passed through to them too quickly.

Balancing the AER preferences with the potential negative customer impacts of a revenue cap or "tight" hybrid price cap, we are considering a hybrid price cap mechanism, potentially with a threshold of 10%. Under this approach, the incremental revenue gain or loss beyond the 10% threshold would be passed on in full to customers or shared between customers and our business. This higher threshold will minimise the volatility from year to year on our customers and allow the business to manage volatility. It will also ensure that there is some incremental adjustment for any significant differences in demand from volume forecasts.

We consider this hybrid mechanism is more consistent with our customer engagement outcomes on our RSP which demonstrated a high preference for high predictability and minimal volatility from year to year in pricing.

14.7 Summary

In this chapter, we have explained how we recover our costs, or building block revenue, through the prices that we charge for providing network services.

Our Draft Plan proposes to cut our network prices over the next AA period by 3.5% on 1 July 2026 followed by increases of 1.5% each year thereafter.

Our proposed price path will enable revenue growth commensurate with changes in our underlying costs.

We have also outlined the changes to our tariff structure and tariff variation mechanism that we are considering and welcome feedback on these options.

Questions for consideration

18. Do you support our objectives of maintaining stable pricing and aligning revenue with underlying costs in setting our proposed price path? Would you prefer an alternative price path, and if so, on what basis?
19. Do you support the options we are considering to adjust the tariff structure (and charge weightings), including an increase in the base charge for residential and commercial customers? If not, what approach would you prefer and why?
20. Do you support the option we are considering for a new hybrid mechanism for revenue control with a 10% revenue variation threshold? If not, would you prefer an alternative approach and if so, why?
21. Do you support the proposed cost pass through events for the Safeguard Mechanism compliance costs and any unrecovered abolishment costs? If not, would you prefer any alternative approaches, and if so, why?

15 Network access

Our current terms and conditions are a key part of our relationship with network users, and we will continue to consult on any refinement required for the next AA period

IN THIS CHAPTER:

- **We do not propose any material changes to our standard terms and conditions**
- **However, we will continue to consult on our terms and conditions through our Draft Plan process**

Our reference service terms and conditions set the contractual arrangements by which Network Users gain access to our distribution network

A key part of our relationship with Network Users[8] is a contractual agreement between the parties that governs the conditions (or terms) of access to our networks, commonly referred to as a 'Haulage Agreement'. 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.

In prior AA periods, we have undertaken extensive engagement on updates to our terms and conditions, including harmonising them nationally across our distribution networks, resulting in the lowest sustainable cost and ease of use for our users.

For the upcoming AA period (2026/27 to 2030/31), we are not proposing any material changes to our terms and conditions, but we have identified one potential area for consideration by our stakeholders, as outlined below.

15.1 Regulatory Framework

We are required under the NGR[9] to specify the terms and conditions on which each reference service will be provided in our Final Plan to the AER by 1 July 2025.

The General Terms and Conditions (GT&Cs) are set out in our AA Document.

15.2 Customer and stakeholder engagement

Our current GT&Cs incorporate considerable consultation with stakeholders over a long period of time. They:

- are harmonised with the Victorian, Albury NSW and Queensland GT&Cs which provides national consistency for Network Users on AGN networks and the Victorian MGN network.
- incorporate standard amendments previously agreed with Network Users through negotiations, and
- incorporate other customer information clauses from other gas businesses' GT&Cs.

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.

At our combined SARG and RRG meeting in February 2025, we

[8] Network Users are primarily gas retailers or self-contracting users of our networks.
[9] NGR 48(d)(ii))

presented our proposed approach and next steps to engaging on the GT&Cs.

We stated how we currently do not propose any material changes but that we will continue to consult through the Draft Plan process, including related to:

- The Unfair Contract Terms legislation, which was introduced on 9 November 2023. AGN is considering the impact of this legislation on its GT&Cs.

We will be sharing a draft of our GT&Cs as part of Draft Plan consultation shortly.

15.3 AA Document

As noted earlier, the AA Document sets out the proposed prices and terms and conditions under which we offer access to our networks. The format of the proposed AA Document remains largely unchanged from the current AA Document.

15.4 Summary

The terms and conditions are a key part of our relationship with network users. Our proposed terms have gone through significant consultation with stakeholders over a considerable period of time. We will continue to consult with Retailers, Self-Contracting Users and other stakeholders on any refinement required for the next AA period.

Question for consideration

22. Do you have any suggested amendments to the current General Terms and Conditions, and if so, what are they and why?

16 Stakeholder questions

We have presented stakeholder questions throughout this document on which we are seeking feedback. Your feedback will help us refine our plans and ultimately put forward a Final Plan that is capable of acceptance.

What we will deliver	1	Do you have any views on what we plan to deliver for the next AA period?
Stakeholder engagement	2	Do you have any feedback on our customer and stakeholder engagement program?
	3	Have we considered customer and stakeholder feedback and responded appropriately in this Draft Plan?
Future of Gas	4	What are your views of the emerging opportunities for customers in South Australia? Are we too optimistic, too pessimistic or is it too early to tell?
	5	Do you support our efforts to remain flexible as the future changes, or should our only concern be the lowest prices for the next five years with no thought of the future?
Pipeline Services	6	Do you think the pipeline and reference services we have proposed are appropriate, or do you think there has been a material change in circumstances that would warrant a change to the reference services that were approved by the AER in November 2024?
	7	Do you think the new abolishment reference service should be charged at partial cost recovery (eg, for a charge of around $250) or full cost recovery ((eg, around $1,000)?
Operating Expenditure	8	Do you have any feedback on the operating activities we have proposed as part of our forecast for the next AA period?
	9	Do you support our approach to forecasting opex? Is there sufficient information to understand our proposals and the basis of the costs included in our forecasts?
Capital Expenditure	10	Do you have any feedback on the capex activities we have proposed as part of our forecast for the next AA period?
	11	Do you support our approach to forecasting capex? Is there sufficient information to understand our proposals and the basis of the costs included?
Capital Base	12	Do you have any comments on our proposed approach to adjusting capital base over the current and next AA period, including how we have taken into account the future of gas?
Financing Costs	13	Do you have any comments on our approach to setting the financing and tax costs in this Draft Plan?
Incentive Schemes	14	Do you support our proposal to maintain the opex efficiency carryover mechanism (ECM)?

Australian Gas Networks

Demand	15	Do you support our proposal to maintain the capital expenditure sharing scheme (CESS)?
	16	Do you support our approach to forecasting demand?
	17	Are there other factors we should consider in developing our demand forecasts?
Revenue and Prices	18	Do you support our objectives of maintaining stable pricing and aligning revenue with underlying costs in setting our proposed price path? Would you prefer an alternative price path, and if so, on what basis?
	19	Do you support the options we are considering to adjust the tariff structure (and charge weightings), including an increase in the base charge for residential and commercial customers? If not, what approach would you prefer and why?
	20	Do you support the option we are considering for a new hybrid mechanism for revenue control with a 10% revenue variation threshold? If not, would you prefer an alternative approach and if so, why?
	21	Do you support the proposed cost pass through events for the Safeguard Mechanism compliance costs and any unrecovered abolishment costs? If not, would you prefer any alternative approaches, and if so, why?
Network Access	22	Do you have any suggested amendments to the current General Terms and Conditions, and if so, what are they and why?
Other	23	Is there anything that our Draft Plan hasn't considered that is important to you?

Glossary			
AA	Access Arrangement	HRS	Haulage Reference Services
ACQ	Annual Contract Quantity	HSE	Health Safety Environment
AEMO	Australian Energy Market Operator	HyP Adelaide	Hydrogen Park Adelaide
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	Inline Inspection
AMP	Asset Management Plan	LTIFR	Lost Time Injury Frequency Rate
AMS	Asset Management Strategy	MDQ	Maximum Daily Quantity
API	Asset Performance Index	MGN	Multinet Gas Networks
ARENA	Australian Renewable Energy Agency	MUS	Multi-User Services
ARS	Ancillary Reference Service	Next AA period	2026/27 to 2030/31
CALD	Culturally and Linguistically Diverse	NGL	National Gas Law
capex	Capital Expenditure	NGR	National Gas Rules
CESS	Capital Expenditure Sharing Scheme	opex	Operating Expenditure
CPI	Consumer Price Index	OTR	Office of the Technical Regulator
CRM	Customer Relationship Management	PJ	Petajoule/s
Current AA period	2021/22 to 2025/26	PMC	Periodic Meter Change
DBP	Dampier Bunbury Pipeline	PSP	Priority Services Program
DBYD	Dial Before You Dig	RAP	Reconciliation Action Plan
DEI	Diversity, Equity and Inclusion	RGGO	Renewable Gas Guarantee of Origin
DMSIP	Distribution Mains and Services Integrity Plan	RoRI	Rate of Return Instrument
DP	Delivery Point	RRG	Retailer Reference Group
DRP	Debt Risk Premium	RSP	Reference Service Proposal
DRS	District Regulating Station	RTU	Remote Terminal Units
EBSS	Efficiency Benefit Sharing Scheme	SARG	South Australian Reference Group
ECM	Efficiency Carryover Mechanism	SCADA	Supervisory Control and Data Acquisition
EDD	Effective Degree Day	SOCI	Security of Critical Infrastructure
ERA	Economic Regulation Authority	TAB	Tax Asset Base
ESCOSA	Essential Services Commission of South Australia	TJ	Terajoule/s
GIS	Geographic Information System	TRIFR	Total Recordable Injury Frequency Rate (the number of total recordable injuries per million hours worked)
GJ	Gigajoule/s	UAFG	Unaccounted for Gas
HDPE	High-Density Polyethylene	WAPC	Weighted Average Price Cap
HIA	Housing Industry Association	WPI	Wage Price Index

Contact us

For **general queries**, please contact:

Lucy Huxter

Stakeholder Engagement Manager

D+61 437 132 103
E regulatoryengagement@agig.com.au
lucy.huxter@agig.com.au

For **regulatory queries**, please contact:

Peter Bucki

Head of Regulation

D+61 8 8418 1112

E Peter.bucki@agig.com.au

For **commercial queries,** please contact:

Grant Macauley

Commercial Manager

D+61 8 8 8418 1158

E Grant.macauley@agig.com.au

Our SA Office

Australia Gas Infrastructure Group

Level 6, 400 King William Street

Adelaide, SA 5000