# 2020-24 Plan

Access Arrangement Information for
ATCO's Mid-West and South-West Gas
Distribution System

EIM # 97510620

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2020-24 Plan


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# Abbreviations and document notes

| | |
|---|---|
| **AA4** | ATCO's fourth Access Arrangement (2014-19) |
| **AA5** | ATCO's fifth Access Arrangement (2020-24) |
| **ACQ** | Annual Contract Quantity |
| **AEMO** | Australian Energy Market Operator |
| **AER** | Australian Energy Regulator |
| **ALARP** | As low as reasonably practicable |
| **ALS** | Asset Lifecycle Strategy |
| **AMP** | Asset Management Plan |
| **AMR** | Automated Meter Reading |
| **ATCO** | ATCO Gas Australia |
| **B&D** | Builders and Developers (customers) |
| **BST** | Base-Step-Trend (method) |
| **C&I** | Commercial and Industrial (customers) |
| **CAPEX** | Capital Expenditure |
| **CEIH** | Clean Energy Innovation Hub |
| **COAG** | Council of Australian Governments |
| **Core** | Core Energy Group |
| **DBNGP** | Dampier to Bunbury Natural Gas Pipeline |
| **DBYD** | Dial-Before-You-Dig |
| **DGM** | Dividend Growth Model |
| **DMIA** | Demand Management Innovation Allowance |
| **DMIS** | Demand Management Incentive Scheme |
| **Draft Plan** | ATCO's 2020-24 Draft Plan released in May 2018 for comment |
| **DRP** | Debt Risk Premium |
| **EDD** | Effective Degree Day |
| **ERA** | Economic Regulation Authority |
| **ERP** | Enterprise Resource Planning (system) |
| **GDS** | Gas Distribution System |
| **GJ** | Gigajoule - one billion ($10^9$) joules |
| **GSP** | Gross State Product |
| **GSSSR** | Gas Standards (Gas Supply and System Safety) Regulations 2000 |
| **HHV** | Higher Heating Value |
| **HP** | High Pressure |
| **HSE** | Health, Safety, and Environment |
| **IGC** | Investment Governance Committee |
| **IT** | Information Technology |
| **KPI** | Key Performance Indicator |
| **LTIFR** | Lost Time Injury Frequency Rate |
| **MRP** | Market Risk Premium |
| **MIRN** | Meter Identification Reference Number |
| **MHQ** | Maximum Hourly Quantity |
| **NGL** | National Gas Access (Western Australia) Law |
| **NGO** | National Gas Objective |
| **NGR** | National Gas Rules |
| **NIS** | Network Innovation Scheme |
| **OPEX** | Operating Expenditure |
| **OPSO** | Over Pressure Shut-off |

| | |
|---|---|
| **PE** | Polyethylene |
| **PGP** | Parmelia Gas Pipeline |
| **PMD** | Pressure Monitoring Device |
| **PMM** | Project Management Manual |
| **PRS** | Pressure Reduction Station |
| **PVC** | Unplasticised Polyvinyl Chloride |
| **RAB** | Regulatory Asset Base |
| **R&D** | Research and Development |
| **SAIDI** | System Average Interruption Duration Index |
| **SAIFI** | System Average Interruption Frequency Index |
| **SCADA** | Supervisory Control and Data Acquisition |
| **SL CAPM** | Sharpe-Lintner Capital Asset Pricing Model |
| **SME** | Small-to-Medium Enterprises |
| **TAB** | Tax Asset Base |
| **TJ** | Terajoule - one trillion ($10^{12}$) joules |
| **UAFG** | Unaccounted for Gas |
| **VoC** | Voice of Customer |
| **WA** | Western Australia |
| **WACC** | Weighted Average Cost of Capital |

## Document notes:

- All forecast and past expenditure values are expressed in real dollars as at 31 December 2019 unless otherwise stated.
- Distribution charges are in nominal dollars unless otherwise stated
- All revenue amounts are expressed in nominal dollars unless otherwise stated.
- Some tables may not add up due to rounding.

# Foreword from the President


ATCO is a global energy and infrastructure company with a large presence across Australia. In Western Australia, we are the business that delivers gas to over 750,000 customers. We are the business that keeps our gas supply safe and reliable. In the event of an incident involving gas, we are the business that attends to gas leaks, gas outages, and emergencies. If you smell gas or notice a problem with gas, simply call 13 13 52 any time of the day or night, and you will be connected to our local contact-centre, based right here in Perth. The contact-centre will dispatch our highly trained gas technicians to attend to every incident, to ensure the safety of our customers, our employees, and the public. There is no greater priority to ATCO than the safety and well-being of the people that make up the communities in which we operate.

I want to acknowledge the Aboriginal people as the Traditional Custodians of the land on which we operate, and to pay our respect to their cultures and Elders, past and present. In the spirit of reconciliation, we are committed to working together for our shared future. ATCO globally has a long history of valuing the importance of indigenous owners, including partnerships with the First Nations in Canada.

Our business continues to expand with the WA population and economy, **with over 18,000 new residential customers, and nearly 600 new commercial and industrial customers, each year over AA4.**

To ensure that this plan addresses the needs of our customers and other stakeholders, we conducted an extensive Voice of Customer program to find out first-hand what our customers and stakeholders are thinking. We have used these insights to guide our proposed investments in the gas network and to tailor the range and scope of services to our customers.

In the current economic climate, affordability remains at the forefront of our planning. We have an excellent track record already with ATCO continually ranked as one of the most efficient energy distribution businesses in Australia. Our operating costs per customer are the lowest in the country, and our customer satisfaction rating the highest; a remarkable combination. However, we are not complacent, and as part of our 2020-24 Plan, we propose to maintain high levels of service, safety, reliability and affordability.

To ensure that this plan addresses the needs of our customers and other stakeholders, we conducted an extensive Voice of Customer program to find out first-hand what our customers and stakeholders are thinking.

We recognise that this is an important and challenging time for the Australian energy sector, with issues such as energy security, energy costs and the global trend to transition to a low carbon economy. Natural gas is an enabler in this transition and innovation has never been more important than it is today. Importantly, our customers are telling us that gas will continue to play a role in their energy mix and are looking for innovative and more efficient ways of using gas in the evolving energy supply chain.

ATCO has never been the type of business that waits around for things to happen; that is why we are developing the Clean Energy Innovation Hub (CEIH) at our major depot in Jandakot. The CEIH will investigate and demonstrate how various cleaner energy sources and energy storage solutions can be integrated into an effective energy grid; combining gas (including renewable gases such as hydrogen and biogas), electricity, and heat for use in homes and industry.

Our 2020-24 Plan aligns with the long-term interests of our customers and the economic and social future of Western Australia. I commend it to you, and I look forward to your support for it. Your feedback and questions are welcome.

**Stevan Green**

President, ATCO Gas Australia.

# 2020-24 PLAN HIGHLIGHTS

Our 2020-24 Plan builds on our top quartile performance over the previous period.
2018 benchmarking ranked ATCO as one of the most efficient operators in our Australian peer group.

Our plan outlines the prices we propose to charge retailers over the 2020-24 period, our intended investments, and our planned services to customers. The plan demonstrates that we have carefully considered where we spend money – considering our customers' needs, our network priorities of safety and reliability, and our rapidly changing energy environment.

## Enabling the GROWTH OF THE WA ECONOMY...

- Connecting 81,000 new residential customers and over 2,000 C&I customers.
- Collaborating with the other utilities to enable the efficient delivery of upgrade works, minimising the disruption and cost to residents and businesses.
- Introducing the Development Rebate Scheme to facilitate gas reticulation in new commercial subdivisions.

## ...while supporting a COMPETITIVE RETAIL MARKET...

- Systems and process improvements to support larger volumes of consumers switching retailers.
- Evolving our digital platforms and our omni-channel approach to make it easier for customers to interact with us before they are connected, while they are connected, and when they disconnect.

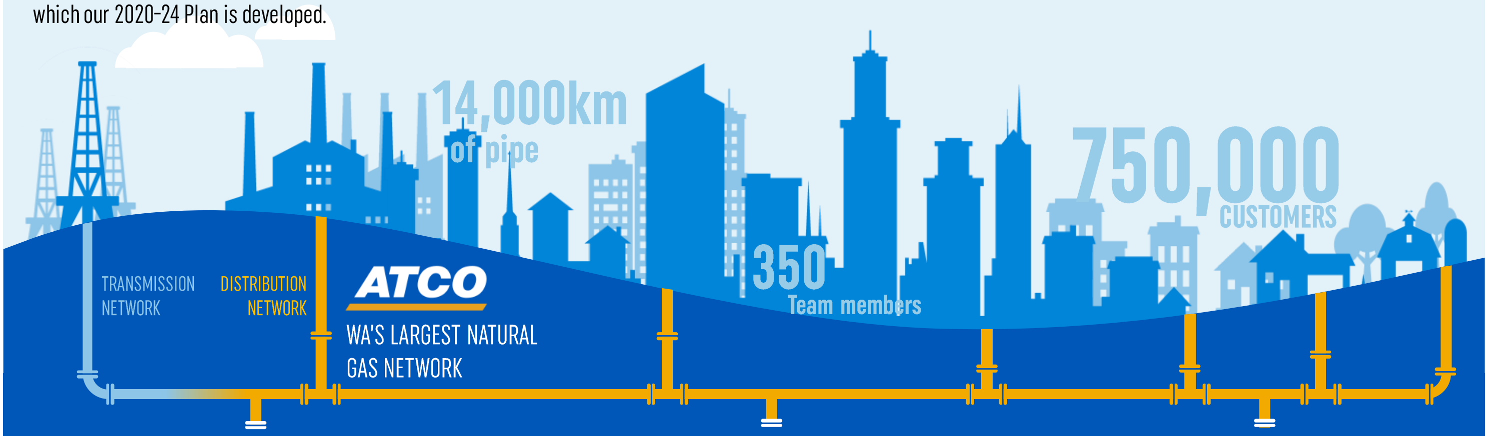
## ... and building a CLEAN ENERGY FUTURE:

- Ensuring our network designs remain efficient, while transitioning to a cleaner energy future through the introduction of renewable gas e.g. biogas and hydrogen.
- Developing the Clean Energy Innovation Hub (CEIH) at our major depot in Jandakot.

OUR **VOICE OF CUSTOMER** PROGRAM

The VoC program is a key input into our many business activities and projects. Meaningful and ongoing engagement with our customers and communities is at the core of how we operate, and is the foundation on which our 2020-24 Plan is developed.

COMMERCIAL & INDUSTRIAL · BUILDERS & DEVELOPERS · SMALL-MEDIUM ENTERPRISES · PEAK/INDUSTRY BODIES · RESIDENTIAL · RETAILERS




## SAFE

**ASSET MANAGEMENT**: Managing our ageing assets to ensure that our network operates at an acceptable level of risk and complies with the relevant legislation.

**EMERGENCY RESPONSE**: Maintaining our local call centre and our 24/7 operational response field crews to allow us to respond to safety incidents raised by the public in a timely manner.

**WORKFORCE SAFETY**: Targeted programs such as the step-touch mitigation program and training. Our workforce has a clear focus on the safety and welfare of our customers and the community.

## RELIABLE

**NETWORK SECURITY**: Investing in security of supply by adding additional supplies to critical parts of the network.

**NETWORK OPERATIONS**: Investments in technology to enable better performance of the network at peak times and improve network resilience against failures.

**NETWORK PROTECTION**: Supporting construction activities occurring near our assets (in particular high-pressure pipelines) to prevent outages and damage.

**REINFORCEMENT**: Reinforcing the gas distribution network to maintain reliability as additional customers connect.

## AFFORDABLE

**MAINTAIN PRICES**: Keeping average prices over 2020-24 at a comparable level with average prices over 2014-2019 (in real terms). The proposed price (in real terms) for an average residential customer at the end of 2024 is *less than it was at the start of 2015.*

**STRONGER INCENTIVES**: Introducing stronger incentives through the regulatory framework to encourage innovation that could deliver benefits over the longer term.

**IT INVESTMENT**: Investments in information technology that will maintain efficient delivery of our services.

# Executive summary

ATCO Gas Australia (**ATCO**) owns and operates Western Australia's largest natural gas network - delivering natural gas to more than 750,000 homes and businesses. Our company vision is to realise the full potential of our infrastructure for the benefit of our customers, suppliers, retailers, and the broader community.

The period 2014-2019 represents ATCO's fourth access arrangement (**AA4**). On 31 August 2018, we submitted a revisions proposal for our *fifth* Access Arrangement (**AA5**) to the Economic Regulation Authority (**ERA**). Our AA5 proposal covers the five-year period 1 January 2020 to 31 December 2024. The ERA will then run a transparent and public process to test that our plans are consistent with the long-term interests of customers.

> "We are operating efficiently while also delivering superior customer service, reliability, and safety.
> Our 2020-24 Plan will sustain this performance, while responding to an external environment that is becoming increasingly competitive, with our customers looking for innovative and affordable energy solutions."

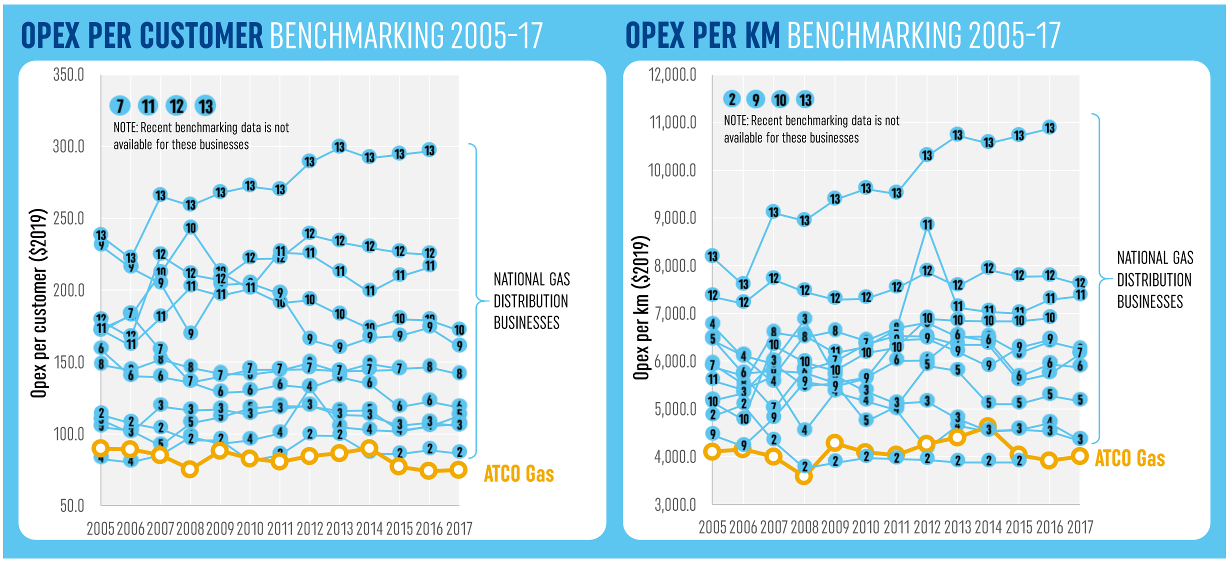
Our commitment for AA5 is to focus on the long-term interests of customers by providing a safe, reliable, and affordable gas distribution network while supporting a competitive retail market, enabling growth for Western Australia, and building the foundation for a clean energy future.

The publication of this 2020-24 Plan is underpinned by an extensive customer and stakeholder engagement program, through which we sought feedback on our planned activities, investment, and proposed services. We believe this plan is robust, efficient, and in the long-term interests of our customers.

## 1.1 Our strong track record

We are independently recognised as one of the most efficient operators in our peer group, with leading performance in operating expenditure (**opex**) benchmarks (see Figure 1.1).

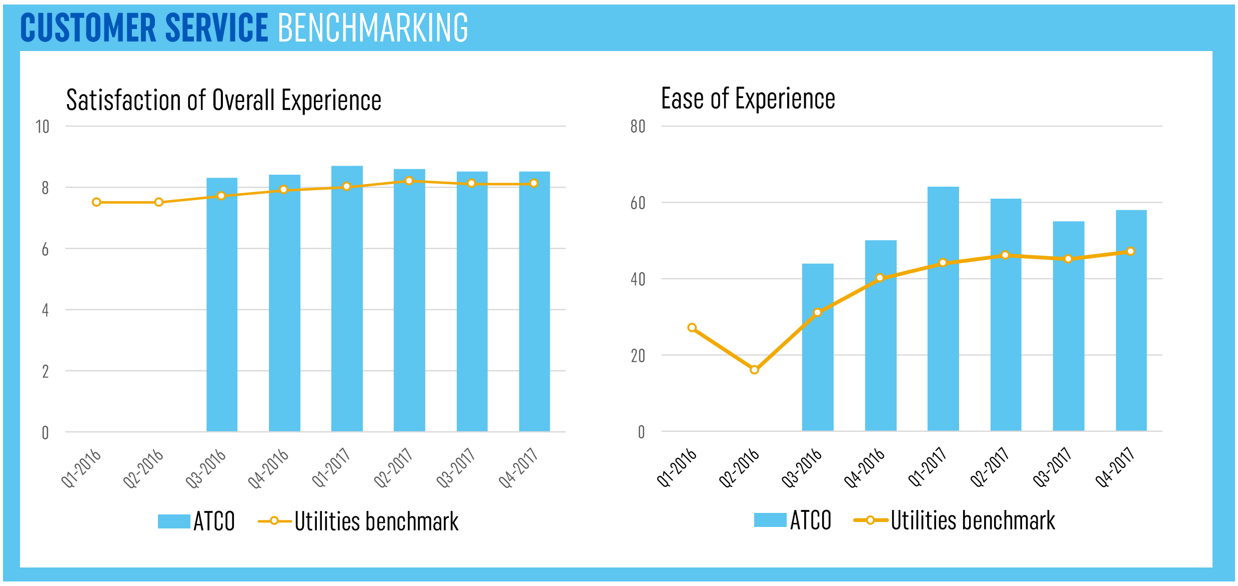
**Figure 1.1:** Operating efficiency benchmarking[1]




[1] Attachment 5.1- Benchmarking Partial Productivity Performance

We have also been independently recognised for our superior customer service, consistently leading the customer service benchmarking study[2] against our national peers since the study began in 2016 (see Figure 1.2).

**Figure 1.2:** Customer service benchmarking




Our major achievements since 2014 also include:

- High customer satisfaction rating. 98.5% of our customers rated us as good or excellent when dealing with new connections and faults.
- 99.9% of broken mains are responded to within one hour of receiving notification.
- Providing high reliability of gas supply to our customers, with customers experiencing supply interruptions for less than 0.5%[3] of the time.
- Facilitating an average of 18,000 new residential connections, and nearly 600 new commercial and industrial connections per year.
- Operating efficiency achievements, including asset management practice improvements and enhancements to our governance oversight practices.
- Delivery of the mains replacement program; we are on track to replace over 280km of mains BETWEEN 2014 and 2019. Between 2017-2019, we are forecast to deliver an average of 58km of replacement per year in a safe and affordable manner.
- Ensuring the ongoing safety of our employees, with a Lost Time Injury Frequency Rate (LTIFR) below industry benchmarks set by Safe Work Australia.

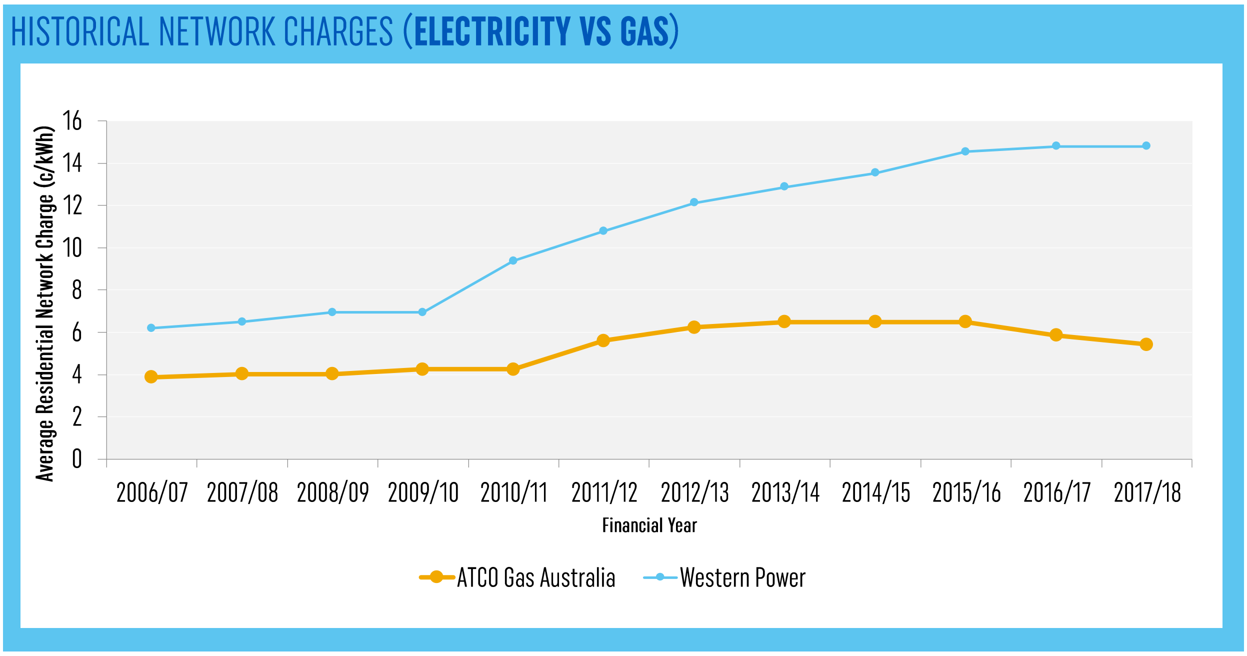
## 1.2 Sustained performance in 2020-24

Our strong performance will continue through 2020-24, recognising that the delivery of stable and affordable energy is critical to Western Australia's growth and prosperity. Natural gas represents approximately 40% of residential energy demand, delivered at less than half the cost of grid-supplied energy, as illustrated in Figure 1.3.

[2] Customer Service Benchmarking Australia (CSBA)

[3] Measured through System Average Interruptions Frequency Index (SAIFI)

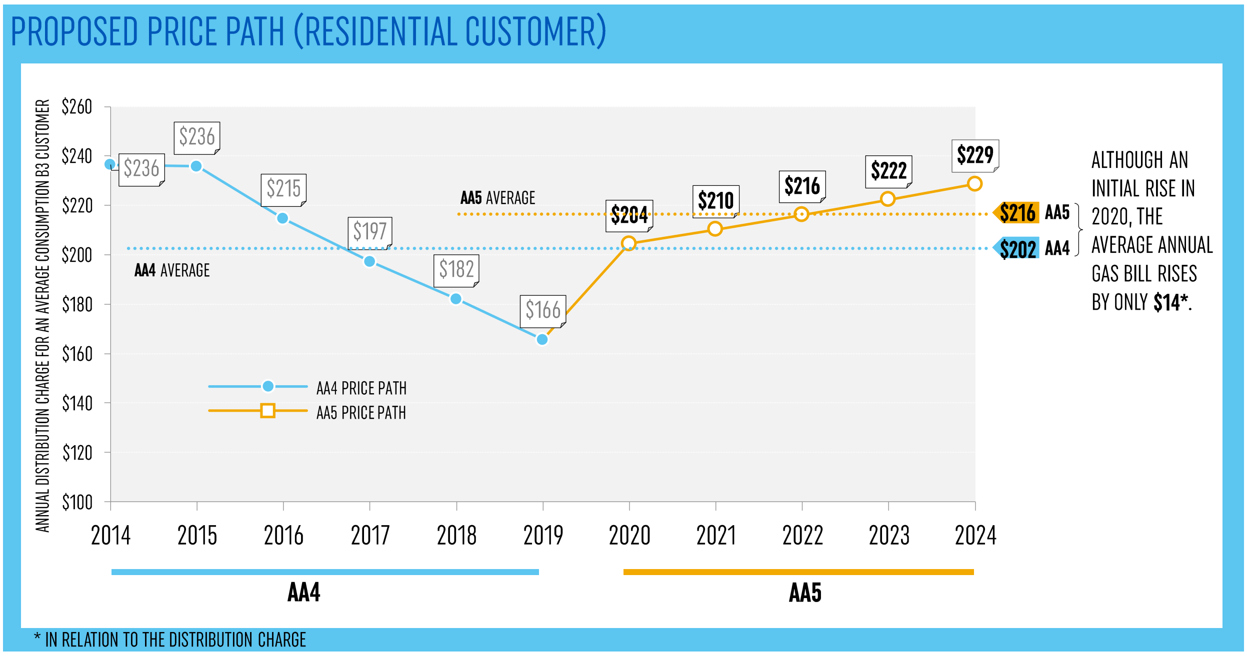
**Figure 1.3:** WA Network charges 2006-2018. Electricity vs Gas




In addition, we remain focussed on providing flexible, innovative solutions to support the State economy now and as our energy environment continues to evolve. Our 2020-24 Plan will:

- Continue to provide a **safe** gas distribution network in accordance with good industry practice, by:
  - Managing our ageing assets to ensure that our network complies with the relevant legislation and operates at an acceptable level of risk. *See Section 12.7.*
  - Investing in the safety of our workforce through targeted programs such as the step-touch mitigation program and through ongoing training. Our workforce has a clear focus on the safety and welfare of our customers and the community.
  - Maintaining our local contact-centre and our 24/7 operational response field crews to allow us to respond to safety incidents raised by the public promptly.
- Maintain **reliable** access to gas by:
  - Investing in the security of supply to support critical parts of the network and reduce the risk of interruption. *See Section 12.7.2.*
  - Reinforcing the network to ensure reliable gas supply is continued as additional customers are connected. *See Section 12.8.2.*
  - Investments in technology to enable better performance of the existing network at peak times and to make the existing network more resilient to damages or failures. *See Section 12.7.4.*
  - Supporting reliability through ongoing replacement, continuous maintenance, and asset protection to prevent outages and damage to our network. *See Section 12.7.*
- Provide **affordable** access to gas at a price reflecting our underlying efficient costs resulting in:
  - Keeping average AA5 charges at a comparable level with average AA4 charges (in real terms). The average distribution charge (nominal, for an average consumption customer) increases between 4% and 11%, compared to inflation over AA4 of 10%. Figure 1.4 outlines the proposed price path for an average residential customer, showing that the average annual charge over AA5 is only $14 higher than it was over AA4. *See Chapter 19.*
  - The distribution charge in nominal terms at the end of 2024 is *less than it was at the start of the AA4 period in 2014 ($229 vs $236 respectively)*. *See Chapter 19.*

**Figure 1.4:** Price path for (B3) residential customers - AA4 to AA5 ($nominal)




- Investments in IT systems that will allow us to continue to deliver our services efficiently. *See Section 12.9.*
- To incentivise investment in innovative technologies and adaptation, we are proposing a network innovation scheme for AA5. *See Chapter 17.*

- Support a **competitive retail market** by:
  - Continuing to improve our systems and processes to support larger volumes of consumers switching retailers, including upgrading our existing billing system. *See Section 12.9.*
  - Evolving our digital platforms and the omni-channel approach (online systems and apps) to make it easier for customers to interact with us before they are connected to the network, while they are connected, and when they disconnect. *See Section 12.9.*
- Enable the **growth of the Western Australia state economy** by:
  - Connecting over 83,000 new customers (81,000 residential and over 2,000 commercial and industrial) during 2020-24. *See Section 12.8.*
  - Supplying an efficient gas energy source to all our customer segments through our dedicated account managers; supporting industry-leading connection timeframes for new and existing customers.
  - Collaborating with the other utilities to enable the efficient delivery of upgrade works, minimising the disruption to residents and businesses during upgrades, and minimising the cost of the works.
  - Introducing the Development Rebate Scheme to facilitate gas reticulation in new commercial subdivisions. *See Section 23.6.1.*
- Build the **foundation for a clean energy future** by:
  - Ensuring our network designs remain efficient while transitioning to a cleaner energy future through the introduction of renewable gas, e.g. biogas and hydrogen.
  - Investing in systems and processes that allow us to monitor higher heating value (**HHV**) and facilitate differential pricing for larger customers. *See Section 12.7.4.*

## 1.3 2020-24 Highlight numbers

| $509M | $357M | 6.03% | $14 | 83K |
|---|---|---|---|---|
| TOTAL CAPEX | TOTAL OPEX | RATE OF RETURN | AVG PRICE INCREASE FOR RESIDENTIAL* | NEW CUSTOMER CONNECTIONS |

*Average annual bill for a residential customer will be $14 higher in 2020-24 than it was in 2015-2019. This is less than inflation.

# PART A:

## Introduction

# 2. Purpose of this Plan

## 2.1 Introduction

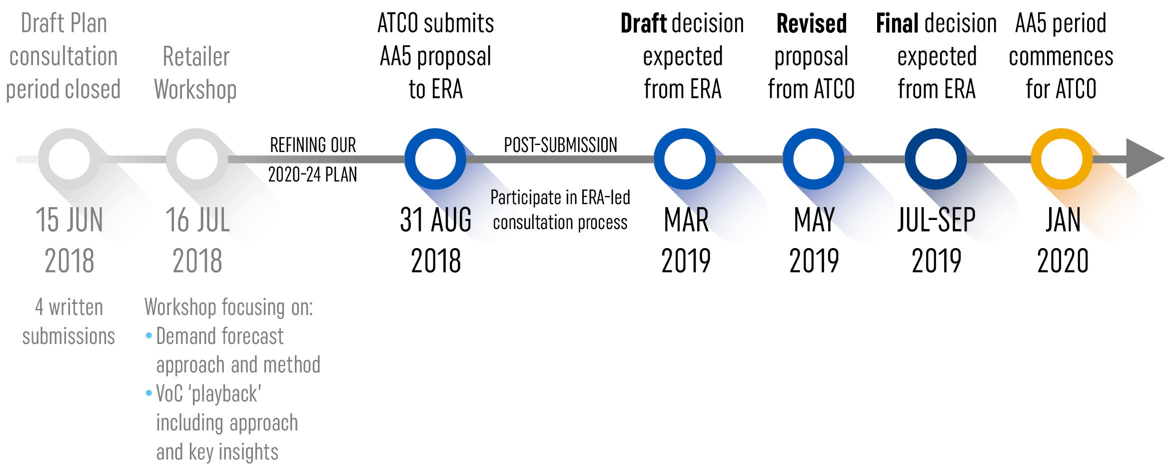
This document outlines the prices we propose to charge retailers over AA5, our intended investment plans, our planned services to Western Australians for the Gas Distribution System (**GDS**) and the findings that emerged from our extensive customer and stakeholder engagement.

The GDS is a designated pipeline under *the National Gas Access (WA) Act 2009*. This means that we are required to periodically submit revisions to our access arrangement to the ERA in accordance with the requirements of the National Gas Rules (**NGR**).

We are required to submit a revisions proposal for the fifth Access Arrangement (**AA5**) period by 3 September 2018. The ERA will review our submission against the NGR and will undertake further public consultation before issuing a draft decision. The ERA will then publish their final decision on our revisions to the access arrangement, see Figure 2.1.

This 2020-24 Plan is also known as the access arrangement information (**AAI**) for our access arrangement revision proposal for the 2020-24 period. The information in this document supports the priorities for our gas network and our services for Western Australian customers. It provides background and supporting information underpinning the access arrangement.

**Figure 2.1:** Expected timeline for the ATCO AA5 proposal




## 2.2 Next steps and feedback opportunities

ATCO's lodgement of the AA5 revisions proposal to the ERA, which includes a revised access arrangement, access arrangement information and supporting documentation, marks the formal commencement of the ERA's review process.

Customer and stakeholder feedback about our planned activities has been incorporated into our proposal. We engaged with customers and stakeholders extensively from September 2017 to June 2018. Our activities are discussed in detail in Chapter 4.

We encourage customers and stakeholders to engage with the ERA public consultation processes. If you have any questions or would like to provide us with feedback on our 2020-24 Plan during the ERA's public consultation process, please contact us via the following options:

1. **Through our website:** https://yourgas.com.au/energy-future/2020-24-plan
2. **Send us an email:** haveyoursay@atco.com.au
3. **Call us:** 08 6163 5000
4. **Post your feedback:** Locked Bag 2, Bibra Lake DC, WA 6965.
5. **Visit us in person**: Please contact Matthew Cronin, GM Strategy & Regulation via email matthew.cronin@atcogas.com.au to arrange an appointment.

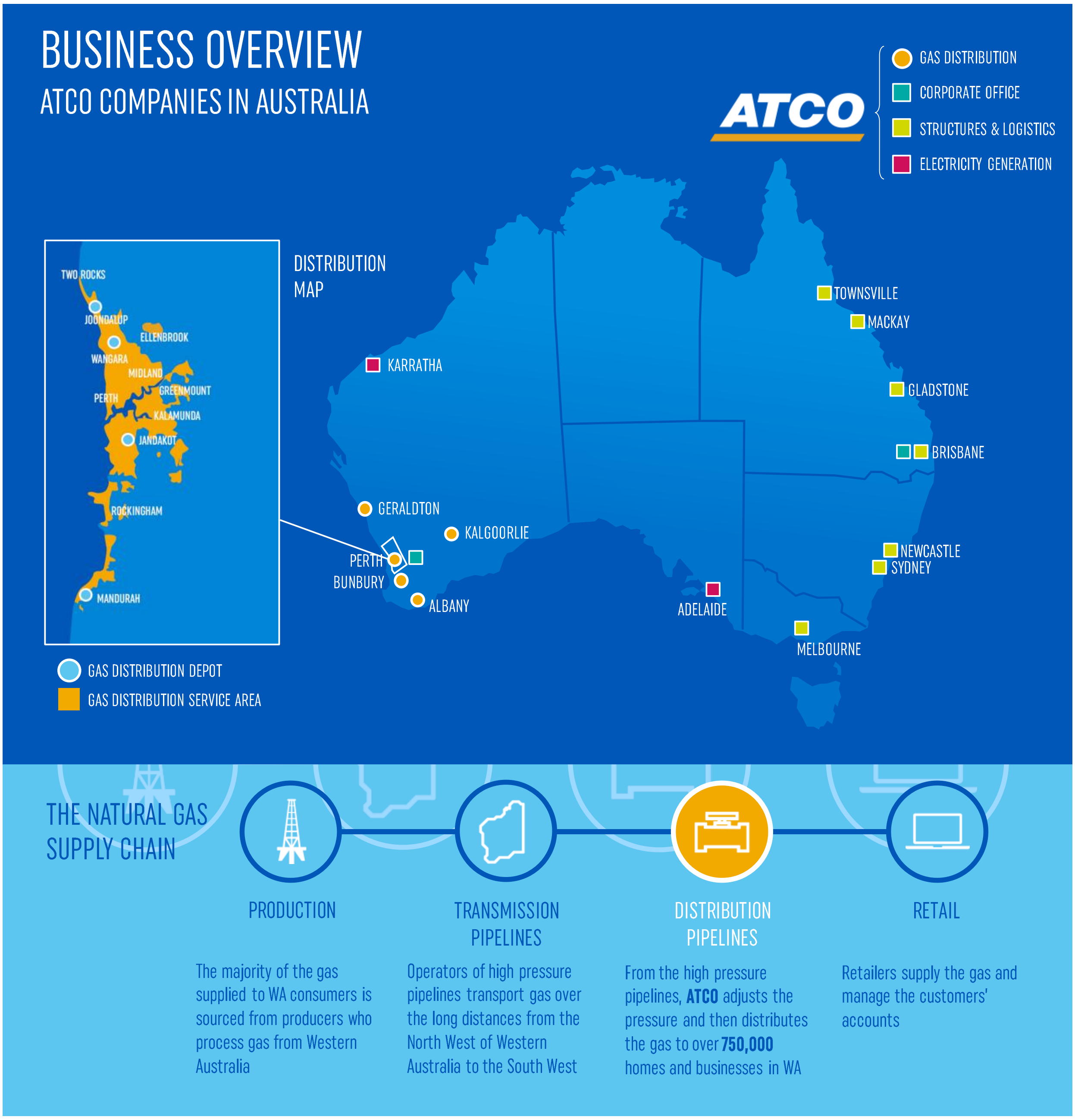
# 3. Business overview

## 3.1 About our business

ATCO Gas Australia (**ATCO**) owns and operates the largest gas infrastructure network in Western Australia: the Mid-West and South-West GDS. Our core business is owning, operating, and maintaining natural gas distribution networks and providing a safe, reliable, and affordable natural gas delivery service to residential, commercial, and industrial customers, see Figure 3.1.

We are ATCO, the largest gas distributor in Western Australia. We help 750,000 customers keep warm in winter, take hot showers, and cook family meals.

**Figure 3.1:** Business overview



Our network supplies approximately 750,000 customers through a network of pipes that are over 14,000 kilometres in length. Our networks are located in Geraldton, Bunbury, Busselton, Harvey, Pinjarra, Brunswick Junction, Capel, and the Perth greater metropolitan area. The network is supported by our workforce of 350 personnel and an additional contracted workforce to deliver a reliable and safe energy source to our Western Australian customers.

This 2020-24 Plan does not include our gas distribution networks in Albany and Kalgoorlie, as these networks do not require an access arrangement proposal to the ERA.

## 3.2 Our role in the natural gas supply chain

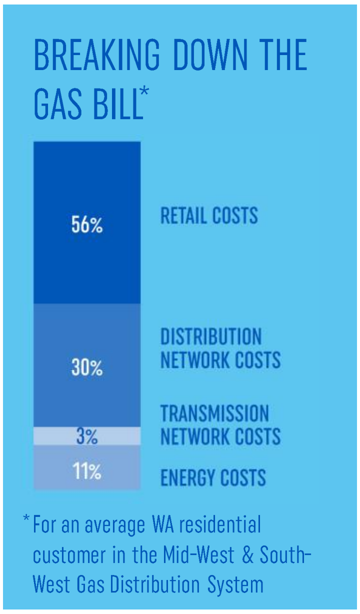
Natural gas is widely recognised as one the safest, most reliable, and cleanest sources of energy, and it has been used as a fuel in Australia for nearly 60 years. Natural gas features strongly in Western Australia's current energy profile – it accounts for around half of the total energy consumption in Western Australia.

Natural gas produces about half the carbon emissions of coal when used for generating electricity and is an important fuel that will support a future with intermittent forms of renewable energy (e.g. wind and solar). Natural gas is, and will remain, a crucial part of Australia's energy mix.

Our role in the natural gas supply chain is to distribute the gas to consumers. Following production and processing, the gas is transported through high-pressure *transmission pipelines* (such as the Dampier to Bunbury Natural Gas Pipeline and the Parmelia Gas Pipeline).

The gas is then delivered to homes and businesses through our gas distribution network. ATCO owns, operates, and maintains the distribution pipelines up to the meter box of the customer, owns and maintains the meter in the meter box and conducts the meter readings at each property.

**Figure 3.2:** The gas bill




Retailers then organise gas contracts from producers and on-sell gas to consumers. Retailers are also responsible for managing the customers' accounts and are the primary consumer contact point.

All the costs associated with the gas supply chain are inputs into customers' gas bills. The network distribution component (ATCO costs) represents approximately 30% of the average residential gas bill[4] (see Figure 3.2).

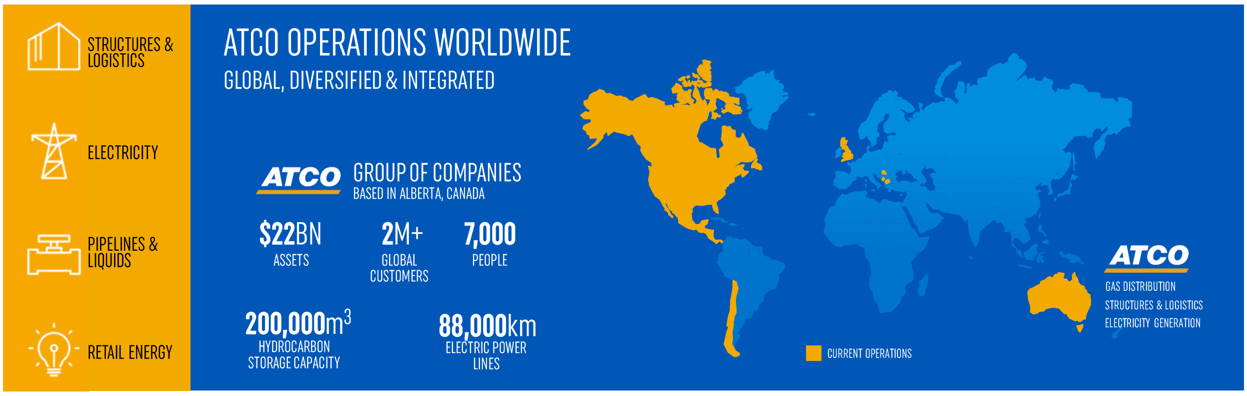
## 3.3 Corporate structure

We are the Natural Gas Distribution business within the Pipelines & Liquids Global Business Unit of the ATCO Group of global companies.

The ATCO Group of companies has more than 7,000 employees and assets worth approximately $22 billion (see Figure 3.3). The ATCO Group is engaged in structures and logistics, electricity (generation, transmission, and distribution), pipelines and liquids (natural gas transmission, distribution and infrastructure development, energy storage, and industrial water solutions), and retail energy. Our core vision is to improve the lives of our customers by providing sustainable, innovative, and comprehensive solutions globally.

[4] Note: The 56% retail component includes GST.

**Figure 3.3:** ATCO operations worldwide




## 3.4 Our vision and AA5 commitment

ATCO's vision is to realise the full potential of its infrastructure, with natural gas recognised as an important and valuable energy solution for the people of Western Australia.

Over 2020-24, we expect the continued evolution of a cleaner, more competitive and customer driven energy system. We are confident that safe, reliable, and affordable natural gas will continue to play a substantial role in the energy mix, and importantly, our customers are telling us the same.

Our commitment for 2020-24 is to focus on the long-term interests of customers by providing a safe, reliable, and affordable gas distribution network while supporting a competitive retail market, enabling growth for Western Australia, and building the foundation for a clean energy future.

In line with our vision and the evolving environment, we believe our business priorities are clear. Our commitment for the AA5 period (2020-24), is to focus on the long-term interests of customers by providing a safe, reliable, and affordable gas distribution network while supporting a competitive retail market, enabling growth for Western Australia, and building the foundation for a clean energy future.

## 3.5 Our operating environment

### 3.5.1 Western Australian economy

The Western Australian economy is now in a phase of transition. Western Australian economic conditions remain subdued post the mining construction boom, affecting consumer spending power and placing pressure on energy affordability. Our goal is to maintain our position as one of Australia's most efficient operators and to ensure that our prices reflect this efficiency.

### 3.5.2 Retail gas market

Following the ERA's 2017 decision to grant gas supply licences to Origin, AGL, and Simply Energy, most Western Australian residential customers can now choose between five gas retailers to buy their energy. Alinta Energy's gas retail monopoly ceased in 2013 when Wesfarmers-owned Kleenheat entered the market.

We expect that the new retailers will compete heavily for Western Australia's residential customers and small use business customers. Greater competition will help to drive down gas prices, and we expect that the number of customers wanting to switch retailers will increase substantially. As the network service provider, we want to ensure that our customers can switch quickly and seamlessly, and that we are facilitating this environment of increased competition.

### 3.5.3 A sector in change: *Western Australia's Energy Future*

It is almost impossible to predict what our energy system will look like in the future. Several very different scenarios could occur, and the long-term structure of the energy system will depend on social, political, technological, and economic developments. If history teaches us anything, it is that these developments do not follow smooth and predictable pathways. This scale of market uncertainty presents big challenges for industry players, as well as policymakers and regulators.

Founded on entrepreneurial spirit, ATCO has embraced adaptability and innovation from its earliest days. Adaptability is critical; companies that are prepared for this disruption will survive and flourish, while those that cling to rigid business models will struggle.

This scale of market uncertainty presents big challenges for industry players, as well as policymakers and regulators

Although we can't stop change from occurring, we can plan for how we respond and take advantage of it. We recently completed a study paper as part of our routine strategic surveillance and long-term planning program. The study paper aimed to help Western Australian energy market participants understand, prepare, and respond to our uncertain energy future.

#### *3.5.3.1 What's driving the change?*

Like most jurisdictions, the overarching global trend toward transitioning to a lower carbon future is shaping an increasingly complex national and local energy policy response. It is also a catalyst for innovation and the emergence and adoption of new technologies. Customers, who are now more empowered than ever before, are realising the value of these technologies and the environmental benefits they provide.

We believe the three factors of energy policy, technological change, and customer behaviour will influence the shape of the future energy landscape, see Table 3.1.

**Table 3.1:** Drivers of the future energy landscape

| DRIVING FORCES OF SECTOR CHANGE | | |
|---|---|---|
| ENERGY POLICY | TECHNOLOGICAL CHANGE | CUSTOMER BEHAVIOUR |
| The risks presented by global warming and the drive to decouple emissions from economic activity is shaping public policy and potentially the structure of the energy sector. The Paris climate agreement resulted in 197 countries, including Australia, demonstrating a commitment to reduce greenhouse gas emissions. Many industry commentators believe that a united approach will be required from both the private sector and all levels of government if Australia is to achieve its commitment.<br>However, energy and climate change represent two of the most politically contested areas | Western Australians are custodians of world-class renewable energy resources and have the scientific and engineering capability to transition to a clean energy economy in a carbon-constrained world.<br>Consequently, Western Australia enjoys a significant comparative advantage in 'clean energy production' and is well positioned to capitalise on this global trend.<br>The future direction of technology and its adoption is uncertain. For example, natural gas is produced in greater quantities today than it was five years ago because of | Changing customer behaviour and preferences will play an important role in defining the future Western Australian energy, policy, and technology landscape.<br>Customer sentiment can be both a cause and effect of technological and policy change. Advancing technologies are allowing customers a wider range of new choices over their energy supply options. Conversely, customer demand for new technologies can influence the government to support these opportunities, or alternatively, remove regulatory barriers to their adoption.<br>In Western Australia, the rapid uptake of residential rooftop |

| DRIVING FORCES OF SECTOR CHANGE | | |
|---|---|---|
| ENERGY POLICY | TECHNOLOGICAL CHANGE | CUSTOMER BEHAVIOUR |
| of public policy in Australia. Policy uncertainty adds further complexity to challenges faced by energy utilities when trying to balance the three elements of the energy trilemma (energy affordability, energy security, and environmental sustainability).<br>At the time of writing, the Federal Government's National Energy Guarantee is unlikely to be adopted, and the challenge of aligning all stakeholders remains significant.<br>Continued policy uncertainty will reduce the willingness to invest in long-lived energy sector assets, including both fossil fuel and renewable energy infrastructure. | technological advances in deep sea exploration.<br>However, there is uncertainty over the rate at which greenhouse gas emitting fuels like natural gas will be replaced by very low emission or renewable alternatives.<br>Ultimately however, as clean energy technologies become cost competitive, or even substantially cheaper than conventional alternatives, it is likely that market forces will accelerate their adoption.<br>In particular, the increasing commerciality of energy produced from renewable sources will have major, but also somewhat unpredictable, consequences. | solar and the early installations of energy storage devices indicate that customers are already embracing new energy solutions outside those provided by a typical utility.<br>Existing energy players are compelled to respond to this changing demand, not only by delivering affordable, safe, and reliable energy solutions but also by delivering *new* energy solutions.<br>Based on consistent feedback from our customers, we are embracing this change and has taken the first steps in the journey through the development of our 'GasSola' solution. This system combines photovoltaic (PV) solar panels, battery storage and a gas-powered generator. |

### *3.5.3.2 The four scenarios*

In 2017, we undertook a study that imagined four future energy scenarios for Western Australia between 2018 and 2030 (see Figure 3.4). Using scenarios allows us to contemplate many conceivable futures and helps us resist the tendency to be locked into an outlook that is not adaptable to changing circumstances. The scenarios were developed from energy market modelling that explores the effect on energy demand, network prices and capital investment.

**Figure 3.4:** Energy future scenarios

**SCENARIO 1:** CONTINUATION OF TRENDS

This scenario assumes no meaningful change to the current WA energy landscape. It assumes recent disruptive influences on the WA energy sector continue at their current rate.

**SCENARIO 2:** DECARBONISATION PARTIALLY PURSUED

This scenario assumes rapid growth in large-scale renewables, and a policy/technological choice to support that growth through an increased reliance on gas-fired technologies.

**SCENARIO 3:** DECARBONISATION ACTIVELY PURSUED

This is predominantly a 'policy push' scenario, where governments take a hard stand on forcing rapid emissions reductions, including a State Government 2050 target of 100% renewables.

**SCENARIO 4:** TECHNOLOGY DRIVES DISRUPTION

This is predominantly a 'technology pull' scenario, where rapid improvements in low emissions technologies and associated cost reductions outpace the need for early government intervention to meet carbon reduction targets.

The scenarios did not intend to predict Western Australia's energy future, but to stimulate thinking and foster discussion with, and between, customers, market participants and policymakers. By discussing these futures, we will learn more about their potential effect on our energy market, our customers and how market participants and policymakers might respond.

This response may include incentives for innovation that we believe are particularly important given these potential changes in the energy sector and the emergence of new technologies. We have proposed a 'Network Innovation Scheme' to overcome the disincentive for innovation that is created through the current regulatory framework. Further detail on this scheme is provided in Section 17.7.

In respect to the gas sector, we can identify several scenario outcomes of significance:

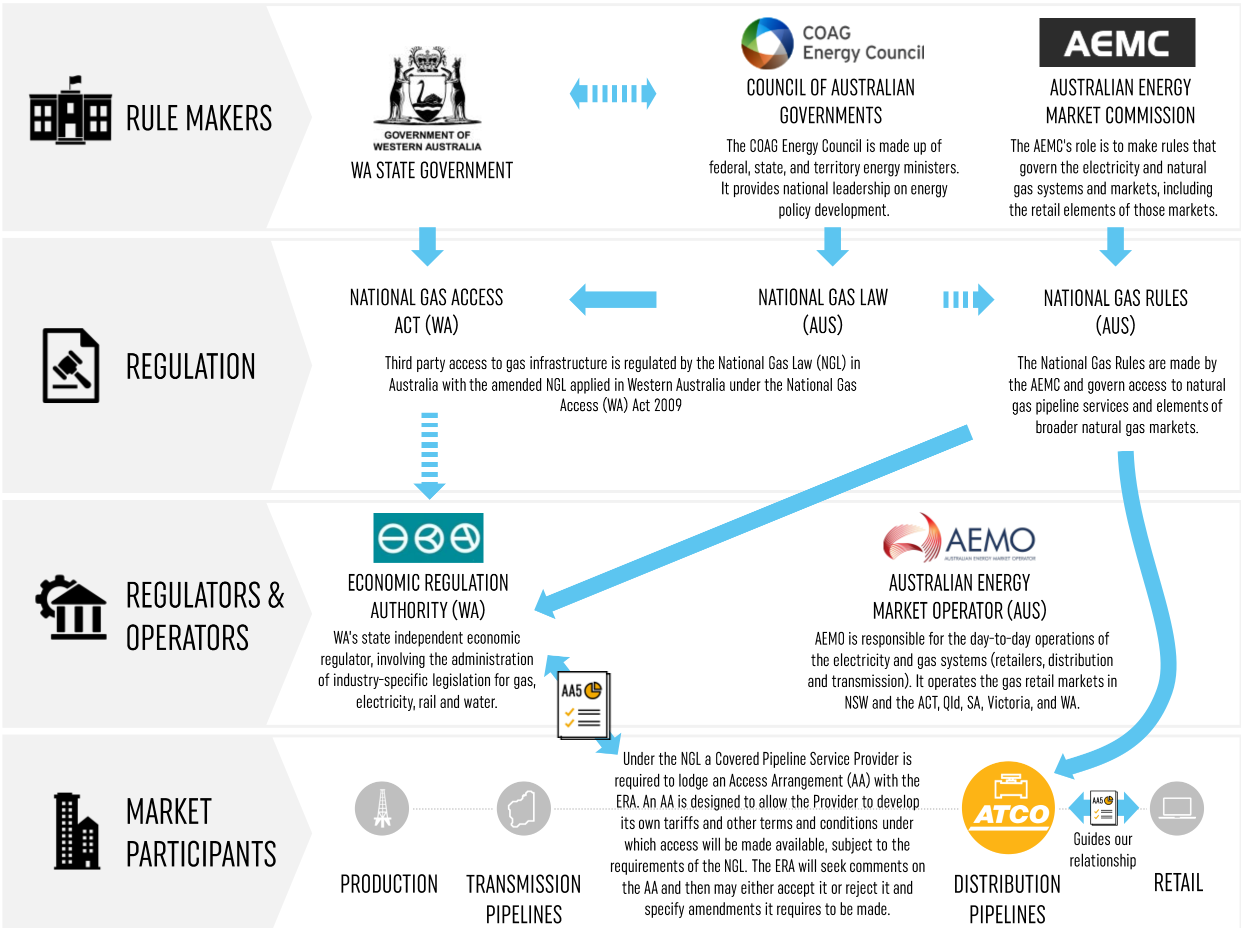
- We found that residential customers continue to demand gas under all scenarios.
- We found that Western Australia's energy future will continue to provide fuel choice for consumers, where they will continue to demand both utility-scale gas and electricity.
- If there is a boom in gas-fired firming capacity to support intermittent energy growth, we expect it will lead to high wholesale gas prices, in turn driving investment in new sources of gas.
- There is continued need to invest in the gas network to meet the needs of consumers, growth in gas connections and growth in consumption.
- If there is a substantial adoption of disruptive gas technologies (such as hydrogen and biogas), there will be increased investment in the gas network, and due to ongoing competition in the retail sector, the gas network continues to provide valuable services to customers well beyond 2030.

These insights were used to inform discussions with our customers and stakeholders as we refined our investment plans and strategies for AA5. We are committed to working with other market participants and policymakers to identify investment opportunities that will deliver sustainable energy solutions for all Western Australians.

## 3.6 Relevant regulatory framework

We operate our networks in accordance with the *Energy Coordination Act 1994*, *National Gas Access (WA) Act 2009* (incorporating the *National Gas Access (Western Australia) Law* (**NGL**)), National Gas Rules (**NGR**), and various state-based operating guidelines. The ERA monitors our compliance with our Gas Distribution Licence, the *National Gas Access (WA) Act 2009*, the NGL and the NGR. See Figure 3.5.

**Figure 3.5:** Our regulatory framework



The NGL and the NGR together provide a framework for the preparation and approval of our AA5 proposal. We have prepared our AA5 proposal in accordance with this regulatory framework.

The overarching standard for regulatory decision making set out in the NGL is the National Gas Objective (**NGO**), stating:

> *"The objective of this Law is to promote efficient investment in, and efficient operation and use of, natural gas services for the long-term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas".*

The NGR set the process to be followed and the regulatory tests to be applied for approval of AA5 in relation to what are called the "building blocks" for allowed total revenue. These building blocks include:

- a return on the capital we have invested and will invest in the network;
- depreciation of that capital;
- an allowance for income tax; and
- our total regulated opex.

Prices are then derived from this total revenue.

We expect some changes in the regulatory framework over the remainder of 2018 concerning the rate of return. On 14 July 2017, the Council of Australian Governments (**COAG**) Energy Council agreed to implement binding guidelines for the rate of return components of the Australian Energy Regulator (**AER**) regulatory determinations for electricity and gas and the ERA regulatory determinations for gas network businesses. Over March and April 2018, the COAG Energy Council consulted on the draft legislation to implement the binding rate of return under the NGL and agreed to introduce the final legislative amendments on 15 June 2018. The legislation to implement the binding guideline was introduced into the South Australian Parliament in August 2018, and we expect that it will be passed into law in Western Australia before the end of 2018.

# 4. Customer and stakeholder engagement

**CHAPTER HIGHLIGHTS**

1. The insights from our Voice of Customer (**VoC**) Program (customer and stakeholder engagement) underpin our 2020-24 Plan.
2. Customers were consulted on their preferences towards price path options, expected service levels, support and priorities for our major investments, and their channel preferences for future ATCO communications.
3. Customers were supportive of our proposed investments and the associated average price increase during 2020-24. The majority of participants prefer an initial price step-up, then price stability, however, retailers prefer gradual and consistent annual price increases.
4. The average support rate for our capital expenditure (**capex**) programs was 95% across our residential and small to medium enterprise (**SME**) participants. 'Mains replacement' consistently ranked as the highest priority when compared to other capex programs, including the mandatory meter replacement program.
5. Customers believed that natural gas has an important role in transitioning to a low carbon future.

## 4.1 Introduction

As a global infrastructure and energy solutions provider for over 70 years, ATCO has built a strong reputation as a customer-focussed business. We recognise that our long-term success depends not only on our ability to understand our customers' requirements today, but also to anticipate their needs and expectations tomorrow.

The 'voice' of our customers is an important input into our many business activities and projects, and we regularly monitor our customers' satisfaction with our service. Feedback is captured and incorporated into our planning; through listening and engagement, we have a unique opportunity to develop innovative solutions to current and future challenges.

Furthermore, we actively seek opportunities to collaborate with indigenous communities to develop new infrastructure solutions. ATCO has a long history of valuing the importance of the First Nations in Canada, where we have more than 40 partnerships with indigenous communities on joint-ventures and infrastructure programs. In Australia, we have a Reconciliation Action Plan, officially endorsed by Reconciliation Australia, which builds on our current relationships and sets the future vision for reconciliation and partnerships with Aboriginal communities, organisations, and Elders.

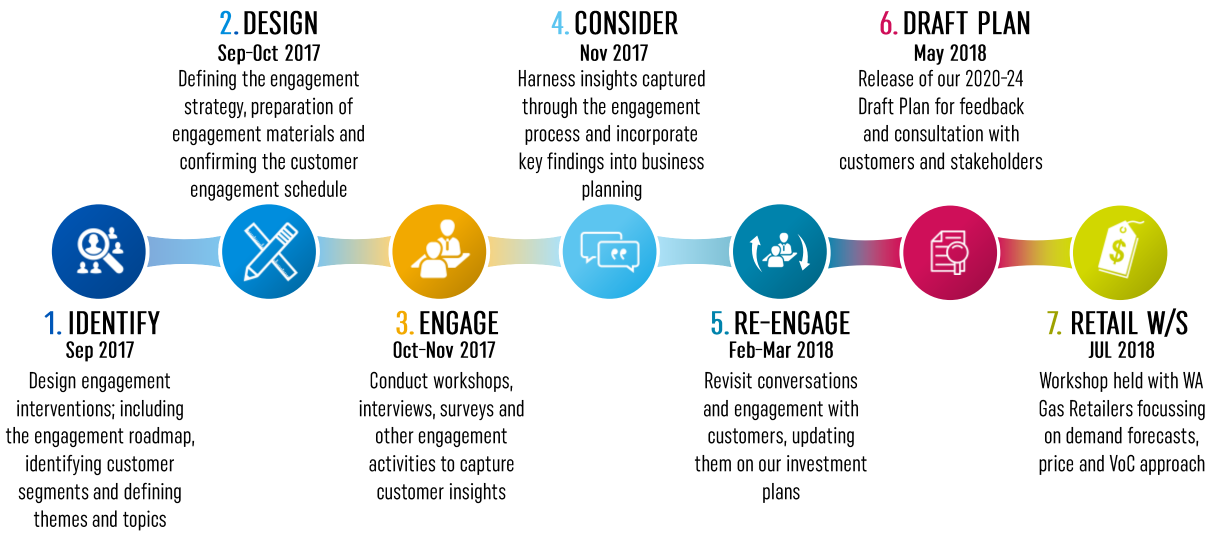
Meaningful and ongoing engagement with our customers and communities is at the core of how we operate and is the foundation of our 2020-24 Plan development. This chapter explains our approach to customer and stakeholder engagement and outlines how the process has affected our respective plan.

> Meaningful and ongoing engagement with our customers and communities is at the core of how we operate, and is the foundation on which our 2020-24 Plan is developed.

## 4.2 Our process for engagement

Our VoC program focussed on creating a dialogue with customers and stakeholders across seven distinct phases, as outlined in Figure 4.1.

**Figure 4.1:** VoC timetable




The VoC program built and extended upon the insights of an early phase of engagement undertaken with gas consumers in December 2016. This engagement was an early exploration of the value proposition of gas, its role within the household energy mix, and its potential role in the future energy landscape.

## 4.3 Who did we engage?

To ensure a fair representation of our customers and stakeholders, our engagement approach reflected a cross-section of customers and geographic locations. Customer representation included residential and SME customers (workshop engagement), and our large commercial and industrial (**C&I**) customers (face-to-face interviews).

Customer participants were recruited by an accredited market research agency to include several demographics; including gender, age, and household income. Workshop participants were provided with an incentive to participate, in accordance with common market research practices. Stakeholder representation consisted of builders and developers (**B&D**) across three tiers, peak and industry bodies, and all current Western Australian retailers. See Figure 4.2.

Senior management from ATCO presented at each workshop, with Deloitte facilitating each session. In executing each of the workshops, content and discussion was tailored to each customer and stakeholder group to maintain high levels of relevancy and engagement.

**Figure 4.2:** Our customer and stakeholder groups

| CUSTOMERS | | | STAKEHOLDERS | | |
|---|---|---|---|---|---|
| RESIDENTIAL | SMALL/MEDIUM ENTERPRISE (**SME**) | COMMERCIAL/ INDUSTRIAL (**C&I**) | BUILDERS AND DEVELOPERS (**B&D**) | PEAK/INDUSTRY BODIES | RETAILERS |
| 6 workshops<br>65 participants | 4 workshops<br>36 participants | 8 interviews | 3 workshops<br>7 participants | 4 interviews | 6 interviews |

## 4.4 Customer insights from the Engage phase (Oct-Nov 2017)

This section outlines the 13 main customer insights from the Engage phase (see Table 4.1), mapped against the five research themes.

**Table 4.1:** Customer insights summary

| 1 About ATCO | 2 Affordability | 3 Safety, Reliability & Growth | 4 Customer Experience | 5 Cleaner Energy Future |
|---|---|---|---|---|
| 1. Natural gas users continue to see the role of gas as an important affordable and reliable source of energy.<br>2. There's a strong desire to learn more about ATCO – what it is we do and what we stand for.<br>3. Providing transparency to consumers about the natural gas supply chain should be a shared responsibility of ATCO and retailers. | 4. Participants were supportive of the average price increase from AA4 to AA5 given the proposed investments.<br>5. The majority of participants prefer an initial price jump, then price stability, when compared to a gradual and consistent annual price increase. | 6. Participants want to maintain the excellent levels of service and reliability they currently enjoy.<br>7. The average support rate for our capex programs is 95% across our residential and SME customer segments, with 'mains replacement' consistently ranked as the highest priority when compared to other capex programs, including the mandatory meter replacement program. | 8. Participants value regular and proactive engagement.<br>9. Clearly defined service levels and value propositions are required for different customer segments.<br>10. Different customer segments have different preferences for communication channels.<br>11. ATCO should promote their existing products (incentives and Capital Contributions Policy) and continue to develop new products. | 12. Participants believed that natural gas has a key role in a low carbon future.<br>13. Pace is important - don't get left behind but don't do it too fast. |

The following sections outline the structure of the Engage phase workshops and the associated insights obtained. Note that some of the charts outlined in this section refer to information relevant to our Draft Plan, which has subsequently been modified to reflect our engagement outcomes.

### 4.4.1 About ATCO

We started the workshops educating participants on ATCO and our role in the Western Australian energy supply chain.

#### Natural gas is seen as an important, affordable, and reliable source of energy

> "Everyone wants gas. Gas is cheaper than electricity, everyone knows that.
> *- Major Land Developer*

Despite having a limited understanding of the gas supply chain, participants acknowledged that natural gas was a more affordable and reliable source of energy when compared with electricity. Customers were also very aware that significant competition exists in the retail gas market in Western Australia, many discussing the discounts they had obtained through switching retailers. There was a strong affinity for using gas with the benefits being identified as convenient, reliable, efficient, and clean.

**Strong desire to learn more about ATCO**

A large proportion of participants were unaware of ATCO and the services we provide. Our role is often confused with a retailer, which is expected given the recent increase in marketing activity by gas retailers in the Western Australian market.

Once informed, participants trusted the business and were very supportive of the initiatives that we were proposing. They supported an expanded marketing expenditure to ensure customers are aware of our role, services, brand, and values.

> “I don't think the general community know about you. I think you need to be more present in the community about what you do and who you are. I thought you were just contracted by Alinta to put the pipes in.
> *- SME Customer*

**Information on the natural gas supply chain should be a shared responsibility**

Our workshops confirmed that customers are also not aware of the role of the local regulator, or the costs that make up their gas bill. When presented with a graphical representation of an average residential gas bill (see Figure 4.3), customers sought clarification on services delivered by other parts of the supply chain, most significantly that of their retailer.

**Figure 4.3:** Services through the gas supply chain[5]


Given the lack of prior knowledge, workshop participants appreciated gaining an understanding of ATCO’s role in the natural gas supply chain and believe that this is information that should be available to all customers. Customers also want transparent information on the components of their gas bill, and how distribution costs will be reflected by retailers over time. Participants considered the provision of this information to be a *shared* responsibility between ATCO and the respective retailers.

## 4.4.2 Affordability

Following the education component of the workshop, we presented our customers with potential price increases for the distribution component of their bill for the next period. We explained that the increases were based on proposed capital works programs for AA5.

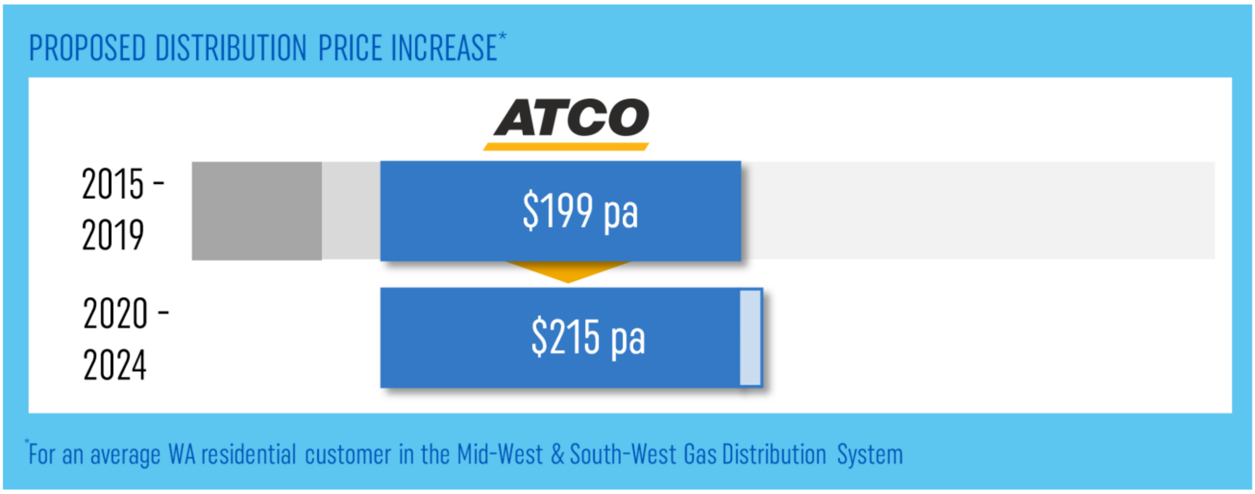
5 Note, the 56% retail component includes GST

### Customers supported our proposed investment and associated average price increases

In general, both residential and SME workshop participants considered the price increase for AA5 as modest, given the projects being considered. Figure 4.4 shows the average annual price increase of $16 compared to the 2015-19 period for residential customers. *Chapter 19* outlines the proposed distribution charge increases for other customer groups.

> It's justified, it's not much.
> *- SME Customer*

**Figure 4.4:** Proposed distribution price increase for residential customers ('Engage Phase')

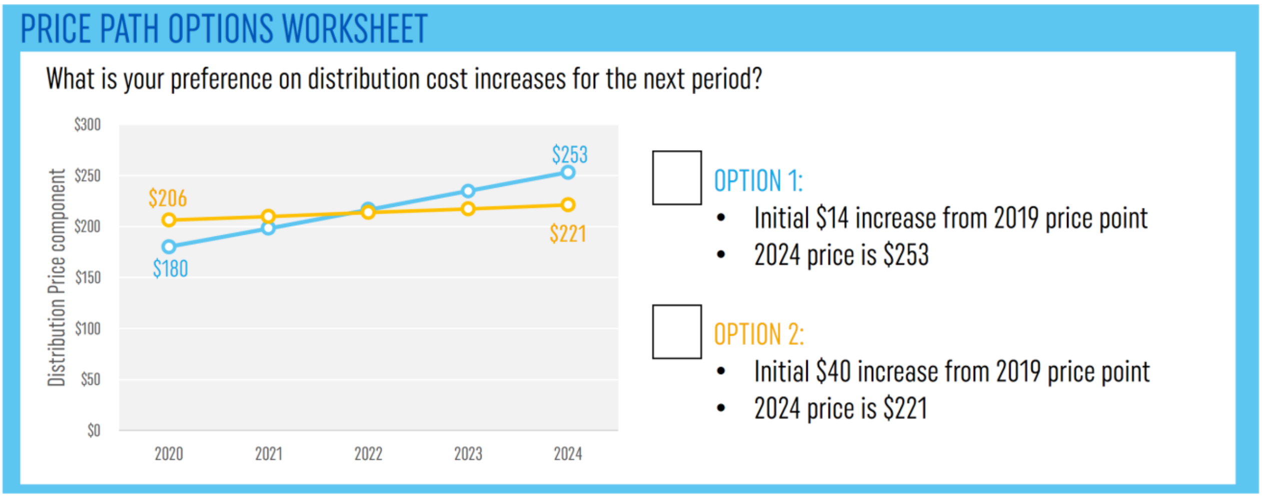



### Participants value price stability

After discussion on the average price increase to customers, we then sought customers' views on *how* the price increase should be introduced over the next period. Through a worksheet activity (see Figure 4.5 for residential worksheet), customers were asked for their preferences on the size of an upfront payment, and subsequent percentage increases in the remaining years of the period. Customers were presented with two options: one option involved an initial step change followed by annual CPI increases, while the other option involved consistent annual increases. However, this did not restrict customers from providing alternate suggestions to us for consideration.

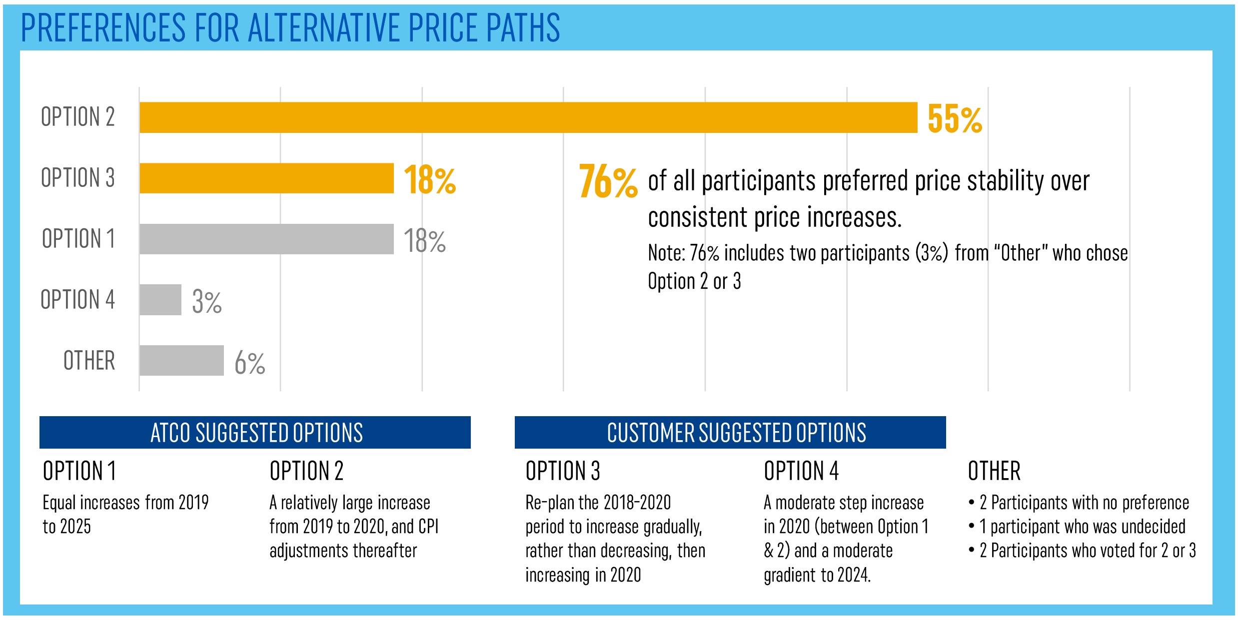
> Knowing these increases, we can actually plan for it – we're not really concerned with either option... that's important for us. If we can't see it, we can't plan.
> *- Large Commercial & Industrial customer.*

**Figure 4.5:** Residential customer worksheet on annual price path options



Most customers (76% overall, with 86% for residential, 74% for SME and 25% for C&I customers) chose a *stable price path* as their preference for paying for the increase in costs, see Figure 4.6. We found that customers tolerated the larger cost increase in the initial year as they viewed the step change as relatively modest.

**Figure 4.6:** Customer preferences for various price path options




### 4.4.3 Safety, reliability, and growth

We then presented four of the major programs that we plan to undertake over AA5 to address safety, reliability, and growth. We sought customers' views on the need and priority of these programs.

**Participants appreciate and want to maintain excellent levels of service and reliability at current prices**

The majority of participants, with very few exceptions, stated they were satisfied with the current reliability and level of service of their gas supply. Customers acknowledged that gas outages were rare and although some recalled outages, the outages really didn't affect them.

Customers also acknowledged that gas was a more reliable source of energy than electricity, particularly those who are outside of the metropolitan area. Given current levels of satisfaction, customers did not consider it cost-effective to pay a higher price for an increased level of reliability or less for reduced reliability. Customers were supportive, however, of investment in the network to continue to maintain existing reliability levels and extend the network for others to be provided with the same service.

**Participants supported proposed capex programs**

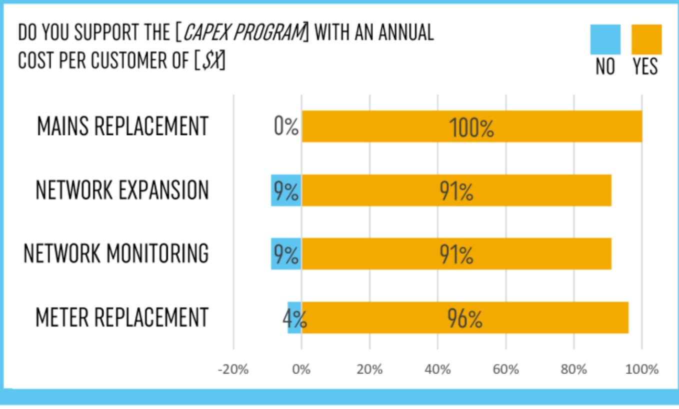
We outlined to customers that continued investment is needed to allow us to both operate and grow a safe and reliable network. As such, we took our customers through four proposed capex programs for AA5.

A summary of the programs is provided in Figure 4.7, including the effect on an average bill for residential and SME customers:

**Figure 4.7:** SME and residential customer support for ATCO capex programs[6]

SUPPORT FOR CAPEX PROGRAM

| | $ / Residential customer pa | $ / SME customer pa |
|---|---|---|
| MAINS REPLACEMENT<br>On-going work required to replace ageing mains pipelines and assets | $12 | $49 |
| NETWORK EXPANSION<br>Upgrades and new pipes to meet current and future demand | $12 | $50 |
| NETWORK MONITORING<br>Monitoring and remote control technology across the network | $5 | $21 |
| METER REPLACEMENT<br>Routine exchange of aged domestic gas meters with new meters | $4 | $17 |




Upon gaining an understanding of ATCO's values, together with the visibility of our performance compared to our peers, customers were very supportive of all the major capex programs. The average support rate for our capex programs was 95% across our residential and SME participants, with mains replacement consistently ranked the highest priority above the statutory meter replacement program.

### 4.4.4 Customer experience

In the next stage of the workshops and interviews, we sought to understand our customers' views on *their experience* with ATCO and what we could do to improve it.

Workshop and interview participants had a good understanding of good (and bad) customer service; customers were quite clear on their expectations of the levels of service they want to receive. Customers also provided insightful advice for further improvements on the customer experience when interacting with ATCO.

**Participants value regular and proactive engagement**

Although the VoC program found that residential and SME customers had limited direct interaction with ATCO, those who have found the customer experience to be excellent. Our customers suggest that we have a reputation for '*getting the job done*' and support enhancing customer experience programs to encourage a direct relationship between ATCO and the end customer (rather than dealing with the retailer).

**Different customer segments expect clearly defined service levels**

Each customer and stakeholder group require a defined set of service levels and value propositions tailored to their specific needs. As to be expected, C&I and B&D customers had a greater expectation and reliance on positive and productive working relationships with ATCO. These groups preferred face-to-face interaction and a dedicated, single point of contact within ATCO.

> "From a development manager's perspective... we know you're there, we know it goes in, it all happens seamlessly.
> *- Major land developer*

6 The average price increase between AA4 and AA5 (e.g. $16 for residential) is the net effect of '$/Residential customer pa' and the $/SME customer pa' figures

**Customers want more options to interact with ATCO**

Despite limited interactions with ATCO, customers would like to see broader channel options to facilitate easy and effective interaction. During the workshops, customers were presented with a worksheet (see Figure 4.8) seeking their input on preferred channels for communication.

**Figure 4.8:** ATCO channel preferences worksheet

CHANNEL PREFERENCES WORKSHEET

How would you like to interact with ATCO?

Rank the methods based on your preferences

| DIGITAL | ONLINE | PHONE | PRINT |
|---|---|---|---|
| • Social Media<br>• Web chat<br>• Mobile App | • Website<br>• Self-serve<br>• Email | • Calls (in/out)<br>• IVR<br>• SMS | • Letter / mail<br>• Fax |

RANK (1-4)

Examples of when you would contact us:

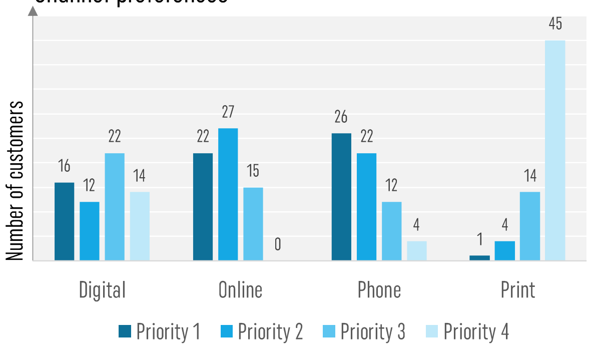
- Gas faults, emergencies or gas supply outages, e.g. smell of gas, gas leak, broken gas pipe, no gas.
- My house: Connection / disconnection, gas supply issues, gas meter enquiries, e.g. meter changes, meter relocation.
- My Suburb: Feedback and queries around maintenance works

While many participants did not understand the circumstances where they would need to contact ATCO, the need for providing a greater choice of communication channels was clear. Channel preferences varied considerably depending on the customer or stakeholder segment.

**Figure 4.9:** Customers' communication channel preferences

COMMUNICATION CHANNEL PREFERENCES

Channel preferences




Preferences by customer segment

| PRIORITY RANK | RESIDENTIAL | SME | B&D |
|---|---|---|---|
| 1st | Phone | Online | Online |
| 2nd | Online | Phone | Phone |
| 3rd | Digital | Digital | Digital |
| 4th | Print | Print | Print |

Our main findings:

- Phone was the most preferred channel (first preference for 38% of participants).
- Online was the second most preferred option, heavily relied on by SME customers.
- Digital was ranked third overall as a channel for communication; ease of access and the flexibility it offers customers appeared attractive.
- Print media was ranked as the lowest preference by 70% of participants.

**Existing products should be promoted more broadly**

Customers flagged brand awareness, marketing, and community education as areas for improvement; particularly when introduced to incentives and clean energy programs. More specifically, there was strong support to continue the Capital Contributions Policy, with many seeing

> "It never crossed my mind that you would be promoting incentives.
> *Builders & Developers customer*

the benefit for greenfield developments. However, in most cases, customers were unaware the policy existed.

Customers considered that lack of advertising and knowledge of our business incentives was a concern. Peak and industry bodies suggested we should improve customers' awareness of our initiatives through case studies and industry engagement, to help inform decisions on how gas could be used more effectively.

### 4.4.5 Cleaner energy future

In the final part of the workshops and interviews, we sought to understand customers' views on the changes occurring in the energy market given the uptake of renewable energy. We explained that we believe gas networks have an important role to play in enabling renewable technologies, as well as offering solutions that balance a changing market, environmental issues, costs, and security of supply.

**Participants believe that natural gas has an important role in a low carbon future**

Our VoC program sought customer views on our initiatives towards a low-carbon future. Most residential customers agreed that steps should be taken towards low-carbon energy solutions. All participants in the B&D workshops showed interest in clean energy solutions, acknowledging possible collaborative opportunities to trial or showcase new gas technologies, especially for micro-grids or community-scale initiatives.

**Keep up with the pace**

Customers were very supportive of the initiatives underway by ATCO and were pleased with the pace and leadership we were providing. Customers believed that taking a steady approach and measured investment in new technology was sensible and logical.

> "The energy world is changing rapidly, why wouldn't you want to be fully engaged with it? If you don't... you'll get left behind.
> - *Resident*

There was overwhelming support for our 'GasSola' trial with many participants interested in the enabling technology, highlighting the opportunities for off-grid living and reducing carbon emissions.

## 4.5 Re-engagement

Customers that participated in the Engage phase were invited back to share their views on our plans as part of the Re-engage phase.

Most of the content of the Re-engage phase was to inform the customers about the considerations that we had made to our plans based on the insights provided during the Engage phase. These included refinements and deferrals made to our major capex programs. Customers were also presented with two alternative approaches for the rollout of the proposed mains replacement program. Content and discussion in the workshops were tailored to each group to maintain high levels of relevancy and engagement.

Customers accepted the refinements made to the four major capex programs, indicating that they trusted ATCO to make the right decisions to maintain safety and reliability. At a program level, customers expressed support for a mains replacement program that minimised disruption and inconvenience.

Consistent with the findings of the Engage phase, customers in the Re-engage phase also supported our proposed average price increases and reiterated their preference for a stable price path following a step change in the initial year.

We also engaged separately with the Western Australia Council of Social Services and the St Vincent de Paul Society as part of the Re-engage phase. This engagement explored affordability issues and community and customer expectations relating to energy services.

## 4.6 Customer insight reporting

As outlined earlier, Deloitte was engaged to facilitate the 'Engage' and 'Re-engage' phases of the VoC program and develop a report outlining the main insights. This Voice of Customer (**VoC**) Report is provided as Attachment 4.3.

## 4.7 Feedback on our 2020-24 Draft Plan

An important part of our stakeholder engagement program was the release of our 2020-24 Draft Plan ('**Draft Plan**') on 1 May 2018. The Draft Plan allowed our stakeholders to understand our proposed AA5 activities and provide feedback accordingly. In our view, the improvement in stakeholder understanding of our plans improved the nature and quality of the feedback received. The Draft Plan also included many 'topic-specific' questions to guide the reader on potentially important issues to consider.

This was the first time that we have released a draft of our entire proposal for the Mid-West and South West gas distribution network, and it represented a significant step forward in our approach to stakeholder engagement. The Draft Plan outlined the feedback from the Engage and Re-engage phases of the VoC program, the services we intended to provide, the costs we expected to incur, and the prices we proposed to charge over AA5.

We received feedback on the Draft Plan through a combination of written submissions, one-to-one consultations (see Section 4.7.1), and stakeholder workshops (see Section 4.7.2). Feedback was also received via the feedback form available on our dedicated microsite.

### 4.7.1 Feedback on the Draft Plan

Our Draft Plan was open for public consultation for six weeks in total (initial consultation window of four weeks plus a two-week extension). We published the Draft Plan on a dedicated 'microsite' (www.yourgas.com.au/draftplan), issued a press release, and directly contacted stakeholder groups to inform them of its release. We also provided several options for stakeholders to provide their feedback on the Draft Plan, including through email, written submission, feedback in person, telephone, and an online feedback form[7].

We received four written submissions from the following organisations:

- Alinta Energy
- AGL Energy
- Origin Energy
- Wesfarmers Kleenheat Gas

We also received feedback via the electronic form available on the microsite and one-on-one consultations with retailers and government undertaken around the time of the launch of the Draft Plan. The feedback

[7] The written submissions and feedback forms on our 2020-24 Draft Plan are subject to stakeholder confidentiality claims, provided as Attachment 4.4 to this 2020-24 Final Plan.

was broadly supportive, particularly in relation to our customer and stakeholder engagement and our transparent approach to planning for AA5.

Customers that provided feedback on the Draft Plan through the microsite request form made the following comments:[8]

- “A very achievable plan for the 2020-2024 period without the cost blow-outs often seen with forward planning. These are true and honest goals for the future”.
- “I have to say I was very impressed with the way the President (Pat Donovan) and the senior engineer took the trouble to be present and took so much time to evaluate our opinion”.
- “I have read the forward, highlights and executive summary and liked what I read. ATCO gets the thumbs up from me and I feel confident with their present and future operations. I expect the Economic Regulator to also be impressed”.
- “I have not read anything that had not been discussed in the talk night. It appears to be fair and reasonable and reflects the choices and ideas raised. Well done”.

In the written submissions, there was support for the use of the Base-Step-Trend approach to opex. There was also some qualified support for capex intended to support market competition, such as the proposed overhaul of the billing system. However, the written submissions also acknowledged that our proposed capex and opex would be extensively examined and tested through the formal regulatory processes administered by the ERA.

Similarly, while the written submissions suggested retailers were generally comfortable with our proposed approach to the Weighted Average Cost of Capital, there was also a recognition that this variable was largely outside of our control as it would be determined by the ERA.

In the written submissions, some stakeholders requested that we provide additional information or clarification on particular proposals, such as the billing system upgrade and the mains replacement program. Where appropriate, we have included this extra information in this proposed 2020-24 Plan.

Other feedback in the written retailer submissions was focussed on broader process and operational matters, such as cancellation notice periods for scheduled works and access to the Meter Identification Reference Number (MIRN) database. We propose to work directly with retailers to examine and progress these matters.

The written submissions also requested more information on:

- the method used to prepare gas demand forecasts; and
- the insights generated through the VoC program and the method that underpinned our approach to customer engagement.

These issues were explored in a specialist workshop with retailers held at ATCO’s Jandakot Operations Centre on 16 July 2018.

To assist retailer participation in the workshop, we published an explanatory report on our 2020-24 Plan microsite by Core Energy Group that provided detailed information on how we propose to determine future gas demand. The demand forecast detailed in this report replaces the forecast demand data on which our our Draft Plan was based. Retailers were sent a link to this report via email.

See Section 4.7.2 for further detail on the specialist retailer workshop.

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8 Feedback on 2020-24 Draft Plan provided by gas consumers that participated in the Voice of Customer engagement program. For further information see Attachment 4.4 to this 2020-24 Plan.

The incorporation of stakeholder feedback into our 2020-24 Plan is described later in this chapter (see Table 4.3).

### 4.7.2 Specialist retailer workshop

We conducted a workshop to provide an opportunity for retailers to understand the method used to prepare our gas demand forecasts for AA5. The workshop also provided the opportunity to better understand the main insights generated through the VoC program and the approach that underpinned our engagement with customers and stakeholders.

The workshop was attended by representatives from six retailers as summarised in Table 4.2.

**Table 4.2:** Workshop participants

| RETAILER | PARTICIPATION |
|---|---|
| Perth Energy | In person |
| Alinta Energy | In person |
| Kleenheat | In person |
| Synergy | In person |
| AGL | In person and via teleconference |
| Simply Energy | In person |

The workshop session on the VoC was facilitated by Deloitte (ATCO's VoC partner). The sessions on demand were facilitated by Core Energy Group[9]. ATCO senior management[10] also presented at the workshop.

The workshop discussion on the VoC engagement program largely focussed on insights related to pricing and '*price path'* preferences. In the main, retailers were sceptical that consumers would be willing to accept a price path involving an initial step-change in the first year of AA5 followed by a series of smaller increases in subsequent years. In their view, this seems inconsistent with the findings from their consumer-oriented market research programs that consumers are sensitive to price increases.

In response, we emphasised that the workshops were part of a formal *engagement process* with customers and stakeholders, which is distinct from a typical consumer-focussed market research program. As a result, the focus of the workshop was to seek consumer and stakeholder feedback on our early stage plans and proposals for AA5.

Regarding our demand forecasts, retailers indicated they needed to spend more time reviewing the demand forecast outlined in the Core Energy Group report before they could comment further. By the time of submission, no further questions or comments were received from retailers in relation to our new demand forecasts.

Table 4.4 provides a summary of how feedback from the workshop has been incorporated into our 2020-24 Plan.

9 Core Energy Group is a leading independent business intelligence company, focussed on the Australian and international energy and resource value chains.

10 The General Manager of Strategy and Regulation and the General Manager of Customer Sales and Business Development.

### 4.7.3 Follow-up retailer session

As a result of the workshop, we provided an opportunity for interested retailers to view video footage of some of the VoC workshop sessions. Based on the workshop discussion, representatives from Alinta Energy and Kleenheat wanted to view the workshop footage.

This follow-up session was held on 7 August 2018 at ATCO's Jandakot Operations Centre and was attended by representatives from 4 retailers (Alinta, Kleenheat, Perth Energy and Synergy; AGL declined the invitation).

At this follow-up session, retailers viewed recordings of a Residential workshop and an SME workshop from beginning to end. The session stimulated further discussion on our engagement process and the need to balance competing considerations in developing distribution tariff and pricing proposals.

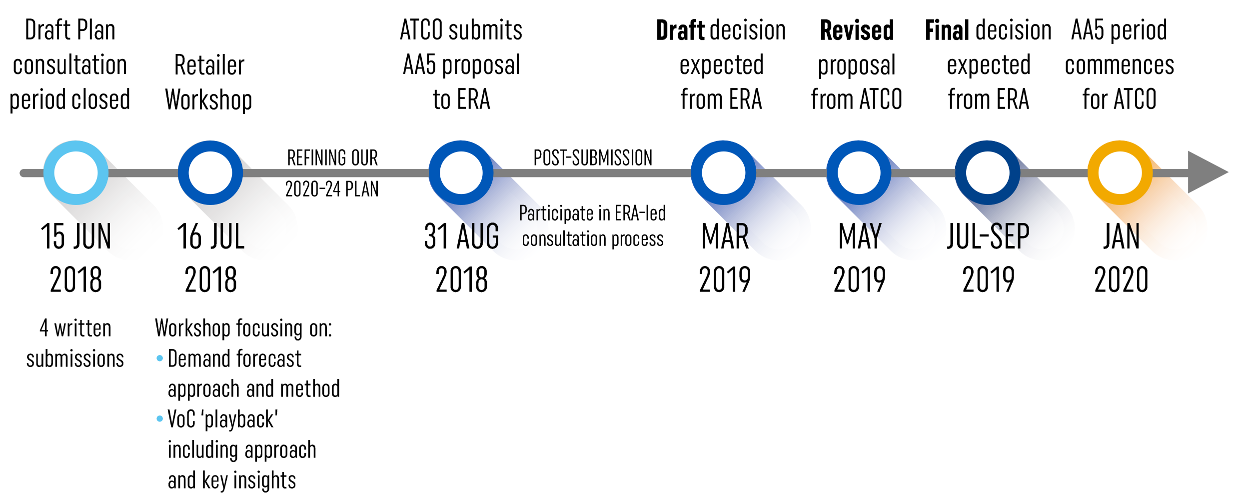
At the conclusion of the session, we offered participants the opportunity to schedule another workshop viewing session. By the time of submission, no further viewing sessions were requested by retailers.

## 4.8 Proposed 2020-24 Plan

This section provides a summary of the feedback received and how that feedback has been reflected in our 2020-24 Plan. Where relevant, individual chapters of this document also include a 'Stakeholder Engagement' section; highlighting feedback received on questions asked in the Draft Plan and how we have responded to this feedback.

We will continue to engage with customers and stakeholders throughout this process and note that the ERA will also undertake its own consultation and engagement program. Figure 4.10 summarises the indicative dates for the development, submission and review of our 2020-24 Plan, including outlining further engagement opportunities.

**Figure 4.10:** Historical and future milestones




### 4.8.1 Incorporation of written submissions on our Draft Plan

Table 4.3 provides a summary of how feedback from written submissions has been incorporated into our 2020-24 Plan.

**Table 4.3:** Incorporation of written submissions

| FEEDBACK | RAISED BY | INCORPORATION INTO 2020-24 PLAN |
|---|---|---|
| Strong support for customer engagement approach | Retailer B | We continue to implement our proactive and transparent approach to engagement. |
| Support for introducing 'special meter reading' as a reference service | Retailer B, Retailer A | We are proposing to include special meter reading as a reference service. |
| Strong interest in understanding demand forecast method | Retailer B, Retailer A | The specialist stakeholder workshop provided an opportunity for retailers to better understand our demand forecast method. This 2020-24 Plan also contains additional information on our demand forecast. We consider our demand forecast to be credible and robust. |
| Support for base-step trend approach to opex | Retailer B | As outlined in Chapter 11, we are continuing to adopt this approach in our 2020-24 Plan. |
| Support for ATCO's proposals to reduce unaccounted for gas (UAFG) | Retailer A | As outlined in Chapter 10, we are targeting a UAFG rate of 2.5% in this 2020-24 Plan. |
| Request for more detail on IT capex | Retailer B, Retailer A | This 2020-24 Plan also contains additional information on our proposed IT capex program. |
| Support for the proposed trial of smart meters | Retailer B | As outlined in Chapter 12, we propose to run a smart meter trial. The 2020-24 Plan also outlines the supporting rationale for the proposed trial. |
| Broader smart meter roll-out | Retailer A | As outlined in Chapter 12, we propose to run a smart meter trial. The 2020-24 Plan also outlines the supporting rationale for the proposed trial. |
| Feedback on the scope of the mains replacement program | Retailer A | Additional detail on the mains replacement program is provided in Chapter 10. |
| In principle support for the proposed billing system upgrade and a requirement for further detail | Retailer D | This 2020-24 Plan provides further detail on the proposed billing system upgrade.<br>We propose to engage directly with retailers during AA5 as part of our further scoping and rollout of the billing system upgrade. |
| Feedback that the rate of return (WACC) approach seems reasonable, but ultimately determined by the ERA | Retailer B, Retailer A | We have modified our proposed approach in this 2020-24 Plan to reflect the weighted average cost of capital (**WACC**) parameters published in the ERA's recent Western Power Draft Decision. |
| Feedback on elements of working capital | Retailer B | We have included further detail on working capital in this 2020-24 Plan. |

| FEEDBACK | RAISED BY | INCORPORATION INTO 2020-24 PLAN |
|---|---|---|
| In principle support for proposed Network Innovation Scheme | Retailer A, Retailer B, Retailer C [11] | As outlined in Chapter 17, we have proposed a Network Innovation Scheme in this 2020-24 Plan.<br>We have also outlined further detail on the proposed structure and operation of the scheme, including outlining how the Scheme might apply to specific innovation objectives and activities. |
| Support for retention of current tariff structure | Retailer B | We are proposing to retain the current tariff structure in this 2020-24 Plan. |
| Concerns about the proposed price path for distribution charges and the willingness of customers to accept the initial rise in the first year of AA5 | Retailer B, Retailer A Retailer C | The specialist stakeholder workshop provided an opportunity for retailers to get a better understanding of the price path options tested with customers in the VoC program.<br>The 2020-24 Plan proposes a modified price path for ATCO's distribution charges that seeks to ameliorate potential customer outcomes while at the same time ensuring we can continue to operate and maintain a safe and reliable network and provide long-term value for gas consumers. |
| Feedback on various operational, service, contracting, and metering issues | Retailer B, Retailer A, Retailer D, Retailer C | Where relevant, this 2020-24 Plan contains further information on these matters.<br>We also propose to engage with retailers over the rest of AA4 and through AA5 to examine and address any outstanding matters, especially if they have the potential to affect market competition. |

### 4.8.2 Incorporation of specialist stakeholder workshop feedback

Table 4.4 provides a summary of how feedback received during the specialist stakeholder workshop has been incorporated into this 2020-24 Plan.

**Table 4.4:** Incorporation of specialist stakeholder workshop feedback

| COMPONENT | STAKEHOLDER FEEDBACK | INCORPORATION INTO FINAL PLAN |
|---|---|---|
| Demand forecast method and ATCO's new demand forecasts. | Some retailers indicated they would like to have more detail on the differences between our new demand forecasts and the demand forecasts included in the 2020-24 Draft Plan. | The relevant chapter in the 2020-24 Plan briefly summarises the main differences between the two sets of demand forecasts. We are confident that the demand forecasts presented in this 2020-24 Plan are robust and credible. |

11 Retailer B and Retailer C expressed general support for innovation that benefits consumers but requested more detail on the proposed scheme.

| COMPONENT | STAKEHOLDER FEEDBACK | INCORPORATION INTO FINAL PLAN |
|---|---|---|
| Proposed 'price path' for distribution charges outlined in the Draft Plan. | Retailers expressed concerns about the proposed price path for distribution charges and the willingness of customers to accept the initial rise in the first year of AA5. | The 2020-24 Plan provides more detail on the contextual information that customers were provided with during the workshops.<br>The 2020-24 Plan proposes a modified price path for ATCO's distribution charges that seeks to ameliorate potential customer outcomes while at the same time ensuring we can continue to operate and maintain a safe and reliable network and provide long-term value for gas consumers. |

## 4.9 Ongoing engagement

We propose to continue to engage with our customers and stakeholders outside the formal regulatory process. The purpose of this engagement is to facilitate ongoing improvements in our business, the experience of our customers, and to improve our organisation's appreciation of the social and economic context in which we operate. We will engage directly with retailers, large industrial customers, residential gas customers, and industry and advocacy groups.

We sought feedback on the structure and potential improvements of our stakeholder engagement program in our Draft Plan. Table 4.5 summarises stakeholder feedback on our engagement program against the questions asked in our Draft Plan and how this feedback has been incorporated into our 2020-24 Plan and ongoing engagement activities.

**Table 4.5:** ATCO's stakeholder engagement performance

| DRAFT PLAN STAKEHOLDER QUESTION | STAKEHOLDER FEEDBACK | OUR RESPONSE TO FEEDBACK |
|---|---|---|
| Do you believe that ATCO has the right priorities for 2020-24?<br>Are there any areas that you believe we have missed?<br>Is there anything in our plan that you believe we shouldn't be doing?<br>Do our plans sufficiently address the findings from our stakeholder engagement? | Stakeholders were supportive of ATCO's approach to stakeholder engagement; in particular, commenting on the early timing of the engagement and the level of detail that we were sharing.<br>Feedback provided by customers included in the 'Engage' and 'Re-engage' phase of the VoC program on the Draft Plan suggests strong support, with many commenting on ATCO's transparent and inclusive approach.<br>Feedback from retailers was generally positive, although there was a general acknowledgement that many of the main elements of the Draft Plan, such as proposed capex programs and the rate of return, were largely outside the control of ATCO.<br>Some retailers also requested more detail on specific proposals, such as the billing system upgrade.<br>Other feedback in the written retailer submissions was focussed on broader process and operational matters, such as cancellation notice periods for scheduled works and access to the Meter Identification Reference Number (**MIRN**) database. | We are committed to continuing our meaningful engagement with our stakeholders.<br>Where relevant and appropriate, we have provided further detail in this 2020-24 Plan on specific areas highlighted by retailers, including the proposed billing system upgrade and the proposed approach to mains replacement.<br>We propose to work directly with retailers to examine and progress potential solutions to the process and operational matters highlighted by retailers. |

## 4.10 Summary

We believe that we have delivered an effective stakeholder engagement program that allows us to achieve our objective of submitting a plan that delivers for our customers.

Our engagement program:

- further developed and improved on our previous engagement activities, particularly through the development of, and engagement on, our Draft Plan;
- had a strong commitment from our Executive Team through all phases of engagement;
- was supported by appropriate information and educational materials;
- included a broad range and number of our customers and stakeholder groups;
- provided multiple channels and opportunities for feedback to be provided on our plans; and
- independently captured and reported on all customer and stakeholder feedback.

We are confident that our 2020-24 initiatives are supported by our customers and stakeholders.

# 5. Past performance

**CHAPTER HIGHLIGHTS**

1. We are proud to be delivering customer service levels, safety, and network reliability that meet our customers' expectations.
2. We are forecast to deliver opex improvements of $51 million against the ERA's AA4 Final Decision.
3. Total capex in AA4 is expected to be $496 million, which is in line with the ERA's allowances. Over 60% of our expenditure was focussed on customer-initiated growth projects and continuing our mains replacement program to maintain safety and reliability.
4. We have consistently met our key performance indicators (**KPIs**).
5. We have efficiently delivered our commitments over AA4, and we benchmark as one of the most efficient gas distribution businesses in Australia.

## 5.1 Introduction

ATCO has delivered a strong and balanced performance during AA4. We are proud to be delivering customer service levels, safety and network reliability that meet our customers' expectations while maintaining high levels of operating efficiency compared to our peers.

This chapter describes what we have delivered over AA4 against what was approved by the ERA.

## 5.2 How we performed against our KPIs

We have performed well against the eight KPIs that were incorporated into AA4. Our performance should provide reassurance that we have been delivering services in a manner that meets our customer service expectations, that our asset management practices over AA4 have maintained the integrity of the network, and that our efficiency in delivering the services has improved.

Table 5.1 outlines our performance against the approved KPIs to 2017 and our forecast for the rest of AA4.

**Table 5.1:** ATCO's AA4 KPIs

| KEY PERFORMANCE INDICATOR | TARGET | JUL-DEC 2014 | 2015 | 2016 | 2017 | 2018(f) | 2019(f) |
|---|---|---|---|---|---|---|---|
| **CUSTOMER SERVICE** | | | | | | | |
| Domestic customer connections within five business days | **>99.5%** | 99.3% | 98.9% | 96.3% | 99.3% | 98.4% | 98.4% |
| Attendance to broken mains and services within one hour | **>99.7%** | 99.9% | 99.9% | 100.0% | 100.0% | >98% | >98% |
| Attendance to loss of gas supply within three hours | **>99.7%** | 100.0% | 100.0% | 100.0% | 99.9% | >98% | >98% |
| **NETWORK INTEGRITY** | | | | | | | |
| Total public reported gas leaks per one kilometre main | **<0.70** | 0.63 | 0.66 | 0.82 | 0.64 | 0.65 | 0.65 |
| System Average Interruption Frequency Index (SAIFI) | **<0.0044** | 0.0044 | 0.0040 | 0.0035 | 0.0035 | 0.0039 | 0.0039 |
| Unaccounted for Gas (UAFG) | **See below** | | | | | | |
| **EXPENDITURE** | | | | | | | |
| Opex per km of main | **$5,076** | $4,561 | $4,572 | $4,465 | $4,393 | $4,815 | $4,898 |
| Opex per customer connection | **$101** | $87 | $89 | $85 | $83 | $91 | $93 |

| UNACCOUNTED FOR GAS (UAFG) | JUL-DEC 2014 | 2015 | 2016 | 2017 | 2018(f) | 2019(f) |
|---|---|---|---|---|---|---|
| Target | 2.52% | 2.63% | 2.62% | 2.62% | 2.60% | 2.58% |
| Actual | 2.59% | 2.64% | 2.64% | 2.09% | 2.40% | 2.57% |

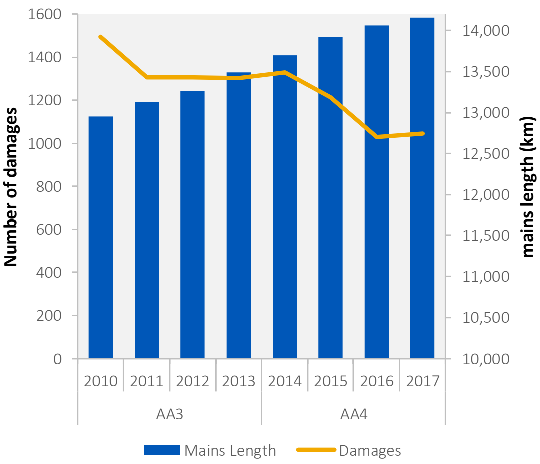
## 5.3 Safety performance

The safety of our workforce and the public will always be a priority. Our safety performance during AA4 has improved materially.

- ATCO aspires to provide a safe and healthy workplace, free of occupational injury and illness; creating a 'Don't Walk By' culture that puts safety first through leadership, training, and development. Health, Safety, and Environment (**HSE**) training is mandatory for all employees, and our frontline employees have completed our 'HSE Leadership Program'.
- The Lost Time Injury Frequency Rate (LTIFR) is a standard industry measure that refers to the number of lost-time injuries within a given period per one million hours worked. Our LTIFR for 2017 is zero; outperforming the industry benchmark of 1.1 set for our sector by Safe Work Australia.

- Third-Party Damage Prevention Systems: Damage prevention is a shared responsibility. Through public awareness and collaboration with industry associations, the public, the excavator community, and regulators, ATCO works to reduce the risks associated with underground activities. The Dial Before You Dig (DBYD) service provides a fast and effective referral service enabling users to access information regarding underground assets at their work site. The program is an enabler for the protection of underground assets, improving safety and minimising disruptions to services. Even with network growth, our third-party prevention systems have helped reduce the number of damaged underground mains due to third-party damage, see Figure 5.1.

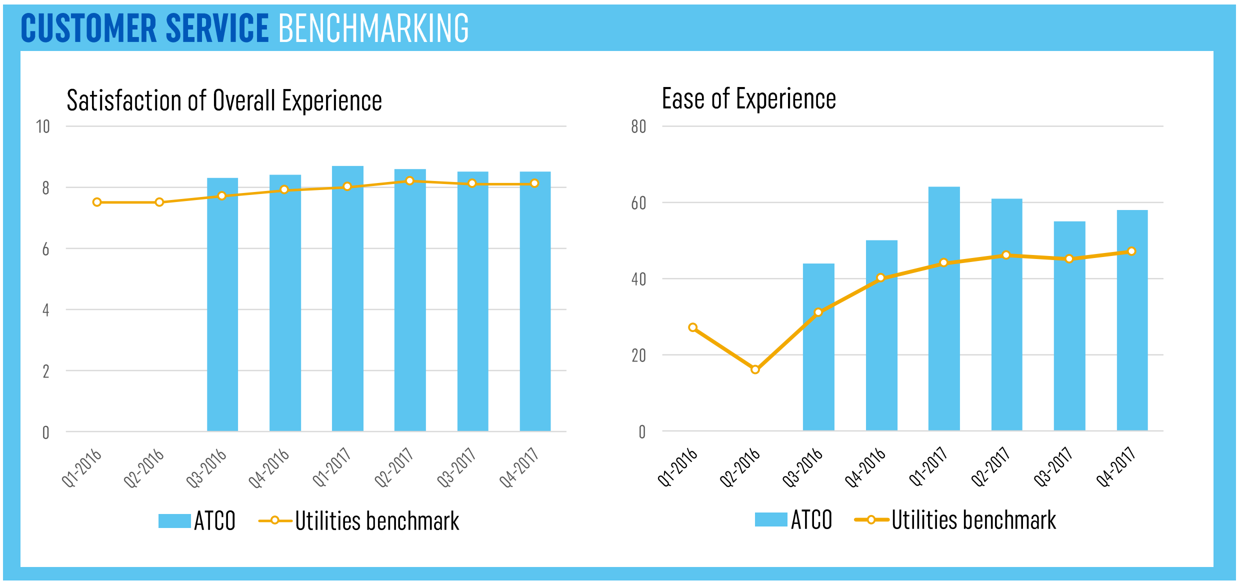
**Figure 5.1:** Mains damage trend




## 5.4 Our customers' experience

ATCO routinely participates in a customer service benchmarking study through national customer service benchmarking provider Customer Service Benchmarking Australia. The quarterly study surveys our customers who have recently transacted with us across unplanned and planned outages and new connections. This allows us to benchmark our performance versus other gas network operators within Australia. Figure 5.2 shows our performance against Australian Gas Networks and Multinet since Quarter 3, 2016. ATCO has been the leader in customer service since the benchmarking exercise began.

**Figure 5.2:** Customer Service Benchmarking Australia performance




During AA4, we have also delivered a strong performance across other customer metrics, including:

- Delivering on average 18,000 new residential connections, and nearly 600 new commercial and industrial connections per year.
- Improved customer engagement. We are continuing to build authentic and credible engagement with our customers and stakeholders, with insights incorporated throughout our planning processes.

- High customer satisfaction. 98.5% of our customers rated us as 'good' or 'excellent' when dealing with new connections and faults.
- Efficient customer service: 92% of customer fault and enquiry calls are answered within 60 seconds, and 83% of calls are answered within 20 seconds.
- Averaging over 125,000 customer calls per year.

## 5.5 What we have delivered

We have performed strongly in both our capex and opex programs, with AA4 forecasts expected to be in line with the ERA's approved allowances. This section outlines our AA4 performance for both capex and opex.

### 5.5.1 Capital expenditure (capex) programs

During AA4, we have invested prudently and efficiently in our network investment program consistent with the ERA's approved allowances. Our capex investment profile is shown in Figure 5.3 and Table 5.2. Approximately 75% of our capex was focussed on customer-initiated growth, continuing our mains and meter replacement program, installing new high pressure mains to ensure security of supply, and introducing supervisory control and enhanced data acquisition to maintain safety and reliability.

**Figure 5.3:** Total capex: Actual/forecast v ERA Final Decision (AA4 ERA FD)

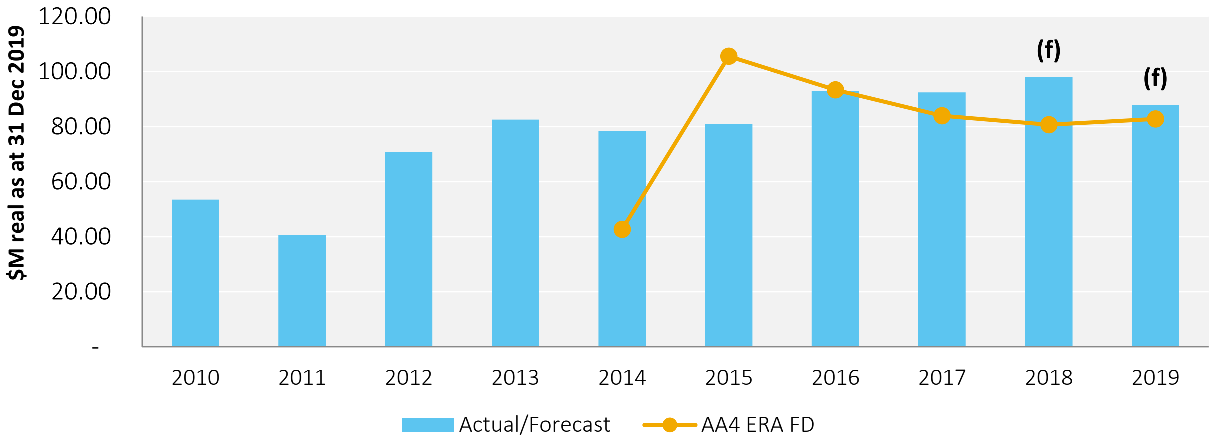



**Table 5.2:** Actual/forecast capex during AA4 ($M real as at 31 December 2019)

| COST DRIVER CATEGORY | 2014 (JUL-DEC) | 2015 | 2016 | 2017 | 2018 | 2019 | TOTAL |
|---|---|---|---|---|---|---|---|
| **Network Sustaining** | 14.5 | 32.7 | 42.7 | 50.3 | 51.8 | 44.2 | **236.2** |
| **Network Growth** | 21.9 | 41.3 | 35.2 | 29.4 | 26.5 | 33.1 | **187.4** |
| **Information Technology** | 5.3 | 3.1 | 8.8 | 7.7 | 3.1 | 2.2 | **30.2** |
| **Structures and Equipment** | 2.2 | 3.9 | 6.1 | 5.0 | 16.6 | 8.4 | **42.1** |
| TOTAL | **43.9** | **80.9** | **92.9** | **92.4** | **98.0** | **87.9** | **496.0** |

Over AA4, our capex program achievements include:

- **On track with our mains replacement program.** We are expecting to replace over 280km[12] of ageing and deteriorating mains by the end of 2019 to maintain network performance and address the high priority public safety risks**.** Between 2017-2019, we are forecast to deliver an average of 58km of mains replacement per year. This mains replacement program includes:
  - The replacement of all identified high risk mains such as low pressure cast iron, unprotected metallic mains and odd size steel.
  - The proactive replacement of unplasticised polyvinyl chloride (**PVC**) mains. We targeted those suburbs with the highest leak rate as well as replacement of PVC mains that were within the area of other replacement projects. By bundling the mains replacement programs together, we achieved a lower unit rate of replacement. Other cost-effective initiatives include collaborating with Water Corporation working in the same replacement areas. This also promotes good relations with local councils and minimises disruptions to our customers.
  - Investigation and the successful trial of 'insertion' as a new mains installation technique (rather than trench digging) to ensure the unit rate of replacement remains cost-effective and minimises disruption to the neighbourhood.
  - Implementation of a semi-qualitative risk-based asset renewal approach using the Mains Replacement Prioritisation tool. This allows us to identify the highest risk and the poorest condition PVC mains for replacement.
- The completion of the **Elizabeth Quay** project; extending our gas network to supply gas to this new tourism, commercial and residential precinct.
- The completion of the **CBD Risk Reduction** project; reducing the operating pressure of the high pressure network in Perth CBD to manage risk and improve the safety of services in the highest density area of our State.
- The completion a safety performance initiative by installing **Over Pressure Shut Off (OPSO) Devices** on high pressure regulating facilities and pressure reduction stations.
- On track to **connect over 100,000 new customers**.
- On track to **replace an average 30,000 domestic meters per year** to maintain the accuracy of our customers' meter reads and ensure compliance with Gas Standards.
- Introduction of High Pressure Regulator *vehicle protection* and *step touch mitigation* programs to ensure the **safety of our personnel working on the network**.
- Modification of gas installations in **multi-storey buildings to reduce the risk of gas release**.
- Completion of **three in-line inspections of our high-pressure steel pipelines** to improve our understanding of asset condition, ageing characteristics and remaining life of our High Pressure (**HP**) steel pipelines. The data will better influence our decision making, planning, and maintenance strategy.
- A **major upgrade of our SAP system** which delivered efficiencies with on-site data collection.
- Investment in **two additional new depots in Joondalup and Busselton** to allow us to service our increasing customer base.
- Completed the **transition from *leasing* to *owning* our fleet** resulting in lower cost to our customers.

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12 Based on 2H 2014-2017 Actual and 2018,2019 Forecast

#### *5.5.1.1 Comparison to Final Decision*

$496 million of capex is forecast by the end of AA4. This amount is $7.0 million[13] ($2019) or 1.4% more than the forecast amount approved by the ERA. Table 5.3 shows AA4 capex by asset class compared to the forecast approved by the ERA. The ERA's approved forecast has been escalated to 2019 dollars using CPI (weighted average of eight capital cities).

**Table 5.3** Capex by asset class – actual/forecast vs ERA AA4 approved forecast (ERA FD) for 2014 -2019 ($M real as at 31 December 2019)

| ASSET CLASS | 2014 (JUL-DEC) | 2015 | 2016 | 2017 | 2018 (f) | 2019 (f) | TOTAL | ERA FD | VAR. |
|---|---|---|---|---|---|---|---|---|---|
| High pressure mains – steel | 0.8 | 0.6 | 2.7 | 7.2 | 5.3 | 2.8 | **19.3** | **28.9** | - 9.6 |
| High pressure mains – polyethylene (PE) | 1.2 | 1.6 | 0.8 | 0.5 | 0.1 | - | **4.2** | **3.5** | 0.7 |
| Medium and low pressure mains | 14.2 | 35.6 | 34.9 | 34.3 | 34.3 | 32.2 | **185.4** | **156.7** | 28.7 |
| Regulators | 1.6 | 2.9 | 4.5 | 5.3 | 2.1 | 0.2 | **16.6** | **11.3** | 5.4 |
| Secondary gate stations | 0.0 | 0.0 | - | 0.2 | 2.1 | 5.5 | **7.8** | **20.1** | - 12.3 |
| Buildings | 0.2 | 0.5 | 0.7 | 1.4 | 10.4 | 4.1 | **17.3** | **14.6** | 2.7 |
| Meter and services pipes | 18.6 | 33.0 | 33.8 | 31.4 | 33.0 | 36.1 | **186.0** | **190.4** | - 4.4 |
| Equipment and vehicles | 0.4 | 1.2 | 1.1 | 1.1 | 2.9 | 0.6 | **7.2** | **6.9** | 0.3 |
| Vehicle | 1.5 | 1.3 | 2.2 | 2.1 | 3.3 | 3.6 | **14.0** | **16.4** | - 2.4 |
| IT (including telemetry) | 5.3 | 3.4 | 9.9 | 8.6 | 4.6 | 2.8 | **34.5** | **34.0** | 0.4 |
| Land | - | 0.9 | 2.4 | 0.4 | - | - | **3.7** | **6.3** | - 2.6 |
| **Sub-Total** | **43.9** | **80.9** | **92.9** | **92.4** | **98.0** | **87.9** | **496.0** | **489.0** | **7.0** |

The variances between the ERA's approved forecast and the expenditure undertaken in AA4 are due to a combination of:

- Prioritisation of replacing high risk metallic mains to ensure a safe and reliable network.
- Delay of Parmelia Gas Pipeline (**PGP**) interconnections.
- Deferral of demand growth projects to align with a slowdown in forecast growth.

The majority of our AA4 capex was incurred in the Network Sustaining and Network Growth categories. A summary of AA4 activity is provided in the following sections:

13 Excludes equity raising costs

### Network sustaining capex

- **Mains replacement**: We have completed cast iron replacement programs as per the AA4 plan. We accelerated the replacement of metallic mains and odd size steel mains to complete the programs by 2019. Metallic mains and odd size steel are high risk assets. In many cases, the metallic mains and odd size steel replacement were in the same suburb, and it was more efficient to bundle the works together and achieve a lower unit rate of replacement.
- **Deferment of PGP interconnection**: We will deliver one PGP interconnection in AA4, and two have been deferred into AA5. During the planning phase of this project, we have been working closely with the transmission operator (APA) to design and develop a cost estimate for the build and installation of the gate station.
- **Phasing of inline inspection:** We have completed inline inspections of two pipelines and will complete a third by the end of AA4. We have used the results and lessons learned from the first inspections to inform and improve the processes and execution of the remaining inspection. Five remaining pipelines will be completed in AA5.

### Network growth capex

- We are on target to deliver our growth capex. New contract rates were established in 2016 through a competitive tender process. 2017 was the first year, and we are realising the benefits from the new contracts. Please refer to Attachment 12.49: '*Unit Rates Forecast*' for more detail.
- We have deferred several reinforcement projects in AA4. We have refined our modelling assumptions to align with a lower growth forecast, resulting in the deferral of several reinforcement projects. These deferrals include mains extensions in the distribution network and one high pressure steel extension in Innaloo.

Table 5.4 shows the ERA's approved forecast compared with our projected AA4 expenditure.

**Table 5.4** ATCO AA4 capex ($M real as at 31 December 2019)

| COST DRIVER CATEGORY | 2014 (JUL-DEC) | 2015 | 2016 | 2017 | 2018 (f) | 2019 (f) | TOTAL AA4 | ERA APP. | VAR |
|---|---|---|---|---|---|---|---|---|---|
| Network Sustaining | 14.5 | 32.7 | 42.7 | 50.3 | 51.8 | 44.2 | **236.2** | **228.7** | **7.5** |
| Network Growth | 21.9 | 41.3 | 35.2 | 29.4 | 26.5 | 33.1 | **187.4** | **187.2** | **0.2** |
| Information Technology | 5.3 | 3.1 | 8.8 | 7.7 | 3.1 | 2.2 | **30.2** | **28.9** | **1.3** |
| Structures & Equipment | 2.2 | 3.9 | 6.1 | 5.0 | 16.6 | 8.4 | **42.1** | **44.2** | **- 2.0** |
| TOTAL | **43.9** | **80.9** | **92.9** | **92.4** | **98.0** | **87.9** | **496.0** | **489.0** | **7.0** |

#### *5.5.1.2 Compliance with Rule 79 (2) of the NGR*

We submit that all the past capex satisfies rule 79(1)(a) of the NGR and is justifiable on the grounds stated in rule 79(2) of the NGR and can be included in the opening capital base.

The AA4 capex is conforming capex under the National Gas Rules because:

- The capex was incurred to provide haulage services utilising a network that is managed in accordance with accepted good industry practice. The capex is invested on a prudent basis in line with business planning and investment governance systems and processes, and the use of efficient procurement practices to achieve the lowest sustainable cost of providing services.

- Growth-related capex satisfies the incremental revenue test.
- The remainder of the capex satisfies at least one of the criteria under either rule 79(2)(a) or rule 79(2)(c) of the NGR.

During AA4, we have had the necessary processes and controls in place to ensure that capex is conforming capex. Our thorough planning and approval processes ensure capex is prudent, efficient and consistent with good industry practice. This involves the rigorous application of technical, managerial and financial governance processes to ensure expenditure meets regulatory, legal and operational obligations in a manner that achieves the lowest sustainable cost of providing services to customers. See Chapter 6 for more detail on our governance approach.

Controls are applied throughout the lifecycle of a project or works program, as per our Investment Governance processes. During the project design phase, alternatives are analysed, and lifecycle asset management principles employed to determine the optimum solution for customers. Gas network demand models are used to ensure network capacity and integrity is maintained to meet customer demand over the long-term.

Network reinforcement and demand projects are phased to ensure minimum supply pressures are maintained and that the network is designed for long-term growth forecasts and security of supply. Such projects may be deferred where load growth or network expansion is less than forecast, and investment can be deferred without risking supply reliability or safety.

Wherever possible, network alterations and extensions are timed to coincide with works undertaken by road authorities, other utilities and land developers. For example, we will seek to coordinate laying new mains with the laying of other services in a common trench such that excavating is only undertaken once.

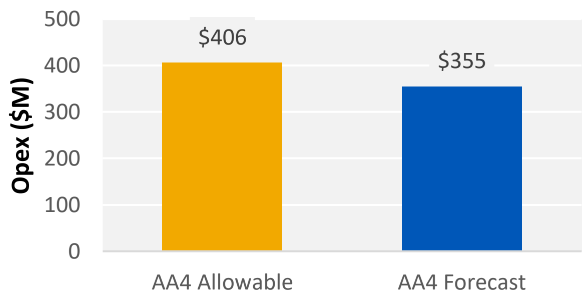
Cost estimates are developed to ensure projects are forecast as accurately as possible, considering historical trends and known future changes such as materials specification revisions. Actual costs are compared against forecast with an approvals process required for cost variations.

For customer-initiated network extensions, economic modelling is undertaken to determine whether the extension passes the incremental revenue test under Rule 79(2)(b) of the NGR. Where the connection does not satisfy this rule, a capital contribution from the customer is requested for the project to proceed. We received $9.5 million of capital contributions over AA4.

### 5.5.2 Operating expenditure (opex)

ATCO is forecast to outperform total opex against the ERA's Final Decision for AA4 by $51 million. This will be achieved through a combination of asset management practice improvements, governance oversight, and efficiency improvements. Figure 5.4 shows the comparison of total opex over AA4 between allowable and actual spend ($M real as at 31 December 2019).

**Figure 5.4:** AA4 Opex, Allowable vs Actual




Our AA4 opex variance against the ERA's approved allowance is driven mainly by:

- implementing safety improvements;
- productivity gains in corporate resourcing and activities;
- enabling shared costs with other agencies; and

- higher reliability in the gas network due to proactive asset management and third-party damage prevention.

Our actual and forecast opex over AA4 is shown in Table 5.5.

**Table 5.5:** Opex actual/forecast as at Dec 2017 ($M real as at 31 December 2019)

| | ACTUAL | | | | FORECAST | | TOTAL |
|---|---|---|---|---|---|---|---|
| | 2014 (JUL-DEC) | 2015 | 2016 | 2017 | 2018 | 2019 | |
| Network | 13.9 | 26.4 | 30.1 | 27.7 | 31.3 | 32.4 | **161.7** |
| Corporate | 11.3 | 18.1 | 13.6 | 16.2 | 19.1 | 19.5 | **97.8** |
| Information technology | 4.3 | 8.8 | 8.5 | 9.7 | 9.0 | 9.3 | **49.6** |
| Unaccounted for gas | 4.4 | 7.9 | 8.2 | 6.0 | 6.1 | 6.9 | **39.4** |
| Ancillary services | 0.2 | 0.9 | 0.9 | 1.0 | 1.9 | 1.5 | **6.5** |
| | **34.0** | **62.0** | **61.2** | **60.7** | **67.4** | **69.5** | **354.9** |

Since 2015, our strong cost control discipline has reduced our opex per kilometre of main by 4% and our opex per customer by 7% as at the end of 2017.

#### *5.5.2.1 Specific operational improvements in AA4*

ATCO continually strives for greater efficiency and lower costs, and has introduced several improvement initiatives during AA4:

- **Proactive third-party damage prevention strategies.** These continued to improve network integrity and community safety with a reduction of 20% in third-party damage over the previous five years and 35% since 2008. Growth in the 'Dial Before You Dig' (DBYD) service has slowed during AA4, from the projected 12% growth to only 3.5% annually in the past two years due to slowing economic conditions. Historically, DBYD has grown on average at 13% annually since 2010.
- **Resourcing improvements.** Resourcing productivity and cost improvements were delivered through a new enterprise agreement and contractor agreement in 2016. The new agreements have delivered efficiencies through contracting activities, such as ancillary services, and delivered cost reductions where contractors were utilised over internal resourcing where appropriate. Regional resources are now completing a broader scope of activities through investment in additional training and tooling, leading to increased productivity.
- **Training of new employees.** ATCO provides bespoke training in gas distribution related tasks as well as investing in programs to provide up-skilling and development of trainees. Our investments in our trainee program align with the increased volume of activity in our business, which has positively influenced the gas industry as a whole.
- **Improved systems.** Electronic 'Notice of Defects' and 'Inspectors Orders' systems have increased our efficiency by removing paper-based systems and unnecessary travel. Additional metropolitan depots have increased coverage and reduced travel time.
- **Process improvements.** Repair techniques and new tooling improvements have meant that activities could be achieved with fewer resources without compromising on safety or quality. Investments in tooling and techniques have reduced third-party service provider costs in traffic management and other areas such as improved unit rates with bundled reinstatement costs.

- **Asset maintenance.** Leak repairs and measurement initiatives have maintained a steady to declining UAFG profile. Increased *proactive* leak surveys have identified more leaks, allowing us to repair them within set KPI timeframes, thus reducing network losses.

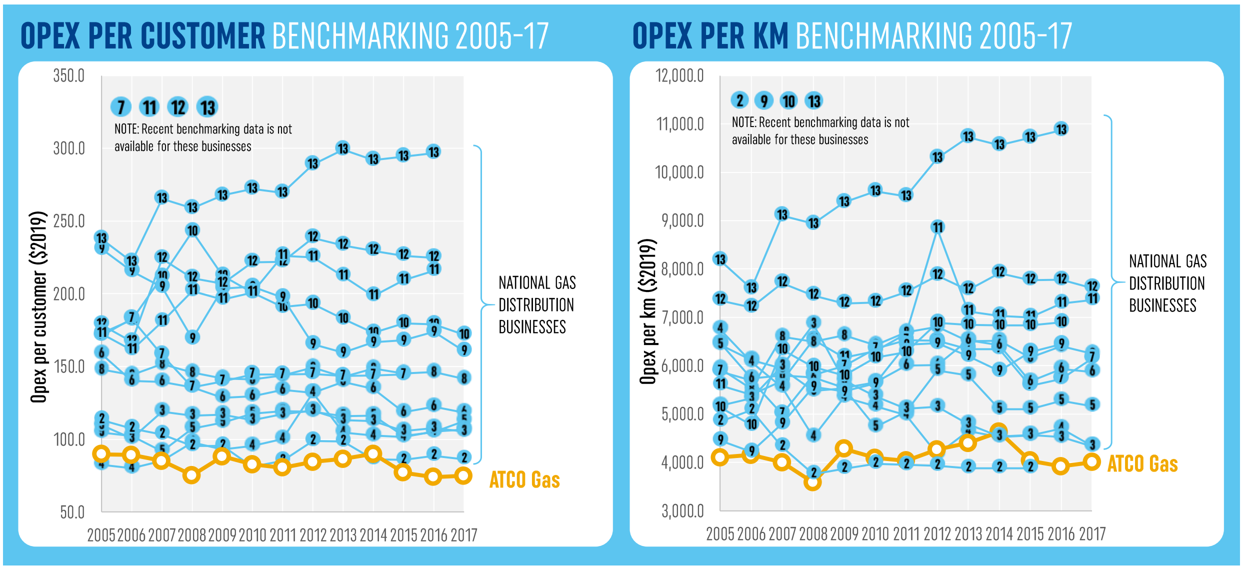
  We have also taken steps for greater network reliability through replacement versus remediation decision frameworks. Small asset replacement continues to have a positive effect, reducing long-term faults and ensuring greater network reliability.
- **Lower corporate costs.** Further synergies between our corporate office and gas distribution operations have contributed to lower corporate opex. Greater alignment of business services such as human resources, payroll, finance, and corporate affairs has improved agility within the support services allowing management to focus on operational improvements and further business development. These improvements will flow through to the forecast number of resources in 2020-24.

Our 2020-24 Plan incorporates the productivity improvements that we have generated over AA4 as part of the forecast opex for AA5.

### 5.5.3 An efficient business

We have been independently recognised as one of the most efficient operators in our peer group, with leading performance in opex benchmarks (see Figure 5.5). Further operating efficiency analysis is outlined in Section 11.6.1.

**Figure 5.5:** Operating efficiency benchmarking[14]




[14] Attachment 5.1- Benchmarking Partial Productivity Performance

# 6. Investment governance

**CHAPTER HIGHLIGHTS**

1. We have a well-established annual planning process through which we update our strategies, plans and investment portfolio.
2. We ensure good governance practices are applied to our investments to ensure ongoing alignment with our corporate strategy and objectives.
3. We apply widely-accepted, standardised project management practices to the delivery of our investment programs.

## 6.1 Introduction

This Chapter outlines the main elements of our investment governance practices. We believe that sound investment governance leads to investment outcomes that are in the long-term interests of customers, shareholders and the community. Investment governance provides the framework to review, evaluate, and approve investments.

## 6.2 Investment governance in context

To ensure we meet the prudence requirements of regulators and shareholders, we manage investments at a portfolio, program, and project level. Our investment governance practices ensure programs and projects:

1. prioritise the safety of the network, employees and the community;
2. make prudent and efficient investment and asset management decisions; and
3. are consistent with accepted good industry practice.

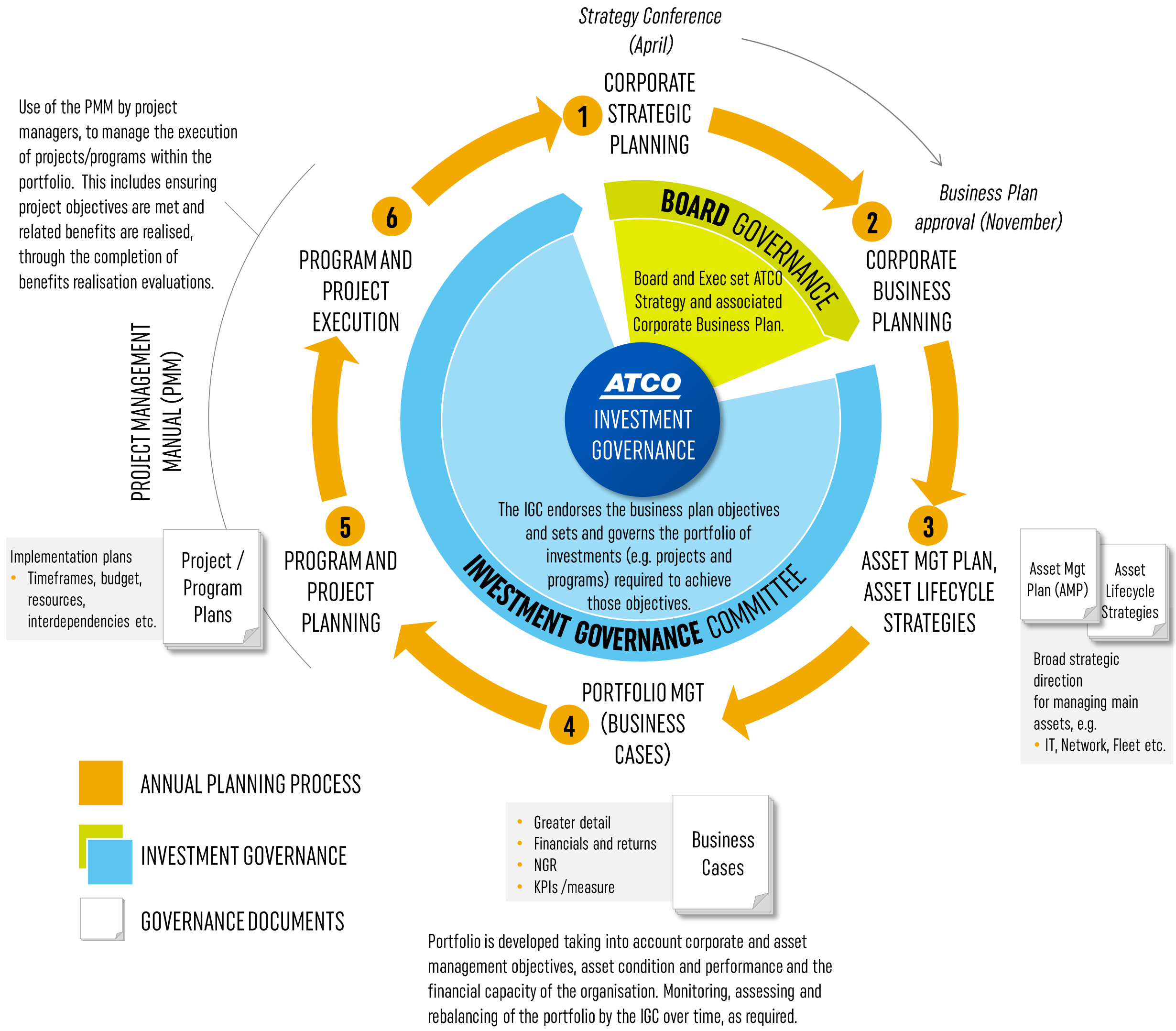
Our investment governance practices ensure that investment activities continue to reflect the strategic reasons for the original decisions to approve, fund and resource projects

## 6.3 Annual planning process

Figure 6.1 outlines our annual planning process, which includes:

- Setting and updating our corporate strategy, business plan, and objectives.
- Updating our Asset Management Plan (**AMP**) and Asset Lifecycle Strategies (**ALS**s).
- Construction of our investment portfolio (projects and programs) to achieve our business plan objectives, within the context of our AMP and ALSs.
- Governance of the portfolio by the Investment Governance Committee (**IGC**) and of individual investments by steering committees and sponsors.
- Monitoring, assessing and rebalancing of the portfolio by the IGC over time, as required.
- Use of our Project Management Manual (**PMM**) by project managers to manage the execution of projects and programs within the portfolio. This structured approach ensures achievement of project objectives and the realisation of related benefits.

**Figure 6.1:** Annual planning process




## 6.4 Investment governance components

Our investment governance practices are comprised of a suite of systems, structures, policies, processes, and resources employed to address our investment responsibilities and ensure alignment between our corporate strategy, objectives, and investments. For example, we have set guiding principles for our investments that state all investments must:

- Ensure the safety of the network, employees and the community
- Align with business strategy and objectives
- Comply with legislation and regulatory obligations
- Be within corporate risk appetite
- Deliver value for money
- Be prioritised against other opportunities
- Have a clear, documented justification
- Be delivered in a controlled manner
- Have clear accountability of outcomes
- Have their returns independently evaluated

Other important components consist of:

- Policies and relevant standards
- Roles and responsibilities (see Section 6.5)
- Systems and processes (see Section 6.6)

## 6.5 Roles and responsibilities

This section provides a summary of our governance structure and the roles and responsibilities of the organisational bodies within that structure (Figure 6.2 provides an overview). Each of these bodies applies governance practices that include a:

- Structure, policies, and procedures for decision-making.
- Progress and performance monitoring process.
- Compliance monitoring process.
- Risk identification and risk management process.

**Figure 6.2:** ATCO governance structure


Our investment governance bodies include:

- The **Board** of our Australian Gas Division:
  Sets corporate strategy with the Executive Team and approves the business plan.
- **Executive Team**:
  Sets corporate strategy with the Board and is accountable for ensuring day-to-day adherence to governance requirements across our business.
- **Investment Governance Committee (IGC)**:
  Endorses the business plan objectives and sets and governs the portfolio of investments (e.g. projects and programs) required to achieve those objectives.
- **Steering Committees**:
  Act as the project governing body, mandatory for all Tier 0 and Tier 1 rated projects (those projects >$1m in value).
- **Sponsors**:
  For all individual investments, have single end-to-end accountability for the realisation of benefits and return on investment.
- **Program and Project Managers**:
  Responsible for the disciplined management of project delivery in line with our PMM.

## 6.6 Systems and processes

### 6.6.1 Project Management Manual (PMM)

The PMM describes the principles, core activities, and deliverables that guide the management of projects to ensure we deliver a safe, reliable, and affordable gas distribution network. The PMM provides a roadmap for project management at ATCO, and uses links to supporting documents, examples and templates.

The PMM is based on widely recognised project management disciplines (see Figure 6.3). The PMM consolidates the fundamental understanding and practices that project managers require to attain project excellence at ATCO. In the spirit of continuous improvement, the PMM is reviewed and updated as new information is acquired and the business environment changes.

**Figure 6.3:** Project management disciplines


The objectives of the PMM are to:

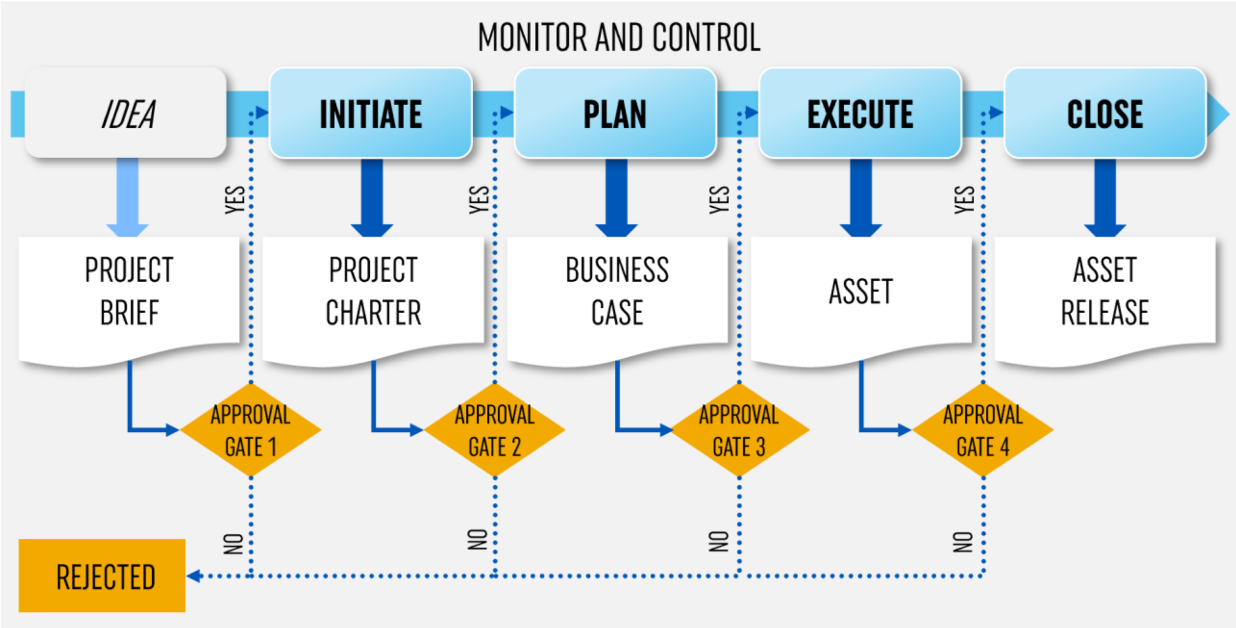
1. Provide a consistent, user-friendly, and traceable project management process, ensuring that outputs are fit for purpose and meet the requirements of our stakeholders.
2. Ensure relevant standards, acts, regulations, codes and expectations of the wider community are considered and applied in a sound professional manner.
3. Establish requirements and protocols so that changes are only undertaken with full consideration of the potential effects of the change and require formal approval prior to implementation.
4. Ensure the project management process is efficient while maintaining high levels of transparency, traceability, governance, accountability, and cost-effectiveness.
5. Define the core processes, actions, responsibilities, deliverables, and assurance gates necessary to deliver high quality projects safely, promptly and cost-effectively.

Under the PMM, we manage projects according to the principles described in:

- ISO 21500 Guidance on Project Management; and
- the Project Management Institute's Project Management Body of Knowledge ("PMBoK").

These two standards define four major 'phases' (i.e. Initiation, Planning, Execution, and Closure). All phases apply to every project and are collectively known as the 'project lifecycle'. These standards establish detailed processes and requirements for each phase and specify agreed 'assurance or *approval* gates'. These gates apply to every project so that management can control and authorise progress from one phase to the next. Figure 6.4 provides an overview of project management at ATCO and outlines the process from 'idea' through to project completion.

**Figure 6.4:** Overview of project management at ATCO




The important points to note in Figure 6.4 are:

- The **assurance or approval gates** between each phase.
- Each phase has **deliverable(s)** (e.g. Initiation Phase produces the Project Charter, Planning Phase produces a Business Case, Execute Phase produces an asset).
- **Project governance** occurs across all phases.

### 6.6.2 Business cases

Business cases provide a standardised way of capturing the drivers for individual investments (projects and programs) and options for achieving the desired outcomes. These outcomes and drivers can include associated benefits, risks and constraints, scope, required resources, budgets and timeframes. At a fundamental level, a business case outlines why we should expend our resources (financial and otherwise) in the pursuit of a particular objective. If the business case is approved by the appropriate authority, the business case becomes the mandate for an investment (project or program) and a high-level outline of what the PM is required to deliver for the project sponsor.

Three important activities completed as part of developing a business case are:

- **Needs identification:** Capex investments are undertaken in response to several drivers, including asset condition, network demand, the need to minimise safety risks, and stakeholder requirements.
- **Options analysis:** Following the identification of a need, consideration is given to the potential solutions to address the underlying driver.
- **Cost Estimation:** Based on a high-level scope of each option, an estimate of the associated costs is developed, using a consistent and robust process.

# PART B:

## Our Proposal

# 7. What we will deliver

**CHAPTER HIGHLIGHTS**

1. Our 2020-24 Plan continues to focus on the long-term interests of customers by providing a safe, reliable, and affordable gas distribution network.
2. Our major initiatives are designed to deliver benefit to Western Australians *well beyond AA5* – ensuring the network supports our low carbon and energy innovation plans.
3. We will deliver programs that support a competitive retail market, enable growth for Western Australia and build the foundation for a clean energy future.
4. Our investment plans have been supported by insights from our VoC program activity.

## 7.1 Introduction

We are experiencing a transformation in the energy sector as the economic, political, and technological underpinnings of our energy supply change in rapid and unpredictable ways. Conventional energy systems are transforming, and the needs of our customers here in Western Australia are changing too.

We have explored the needs of our customers during this time of transformation through our extensive VoC engagement program. We found that our customers strongly support us continuing to explore future energy solutions but prefer us taking a measured approach to moving forward.

We recognise that the delivery of stable and affordable energy is critical to Western Australia's growth and prosperity and we plan to maintain our performance levels into AA5. In addition, we remain focussed on providing flexible, innovative solutions to support the State economy now and as our energy environment continues to evolve.

These insights have been used to enhance our various strategies and plans, with corresponding forecast expenditure rigorously challenged in our bottom-up and top-down business planning and investment governance processes (see Chapter 6).

## 7.2 Our plans for 2020-24

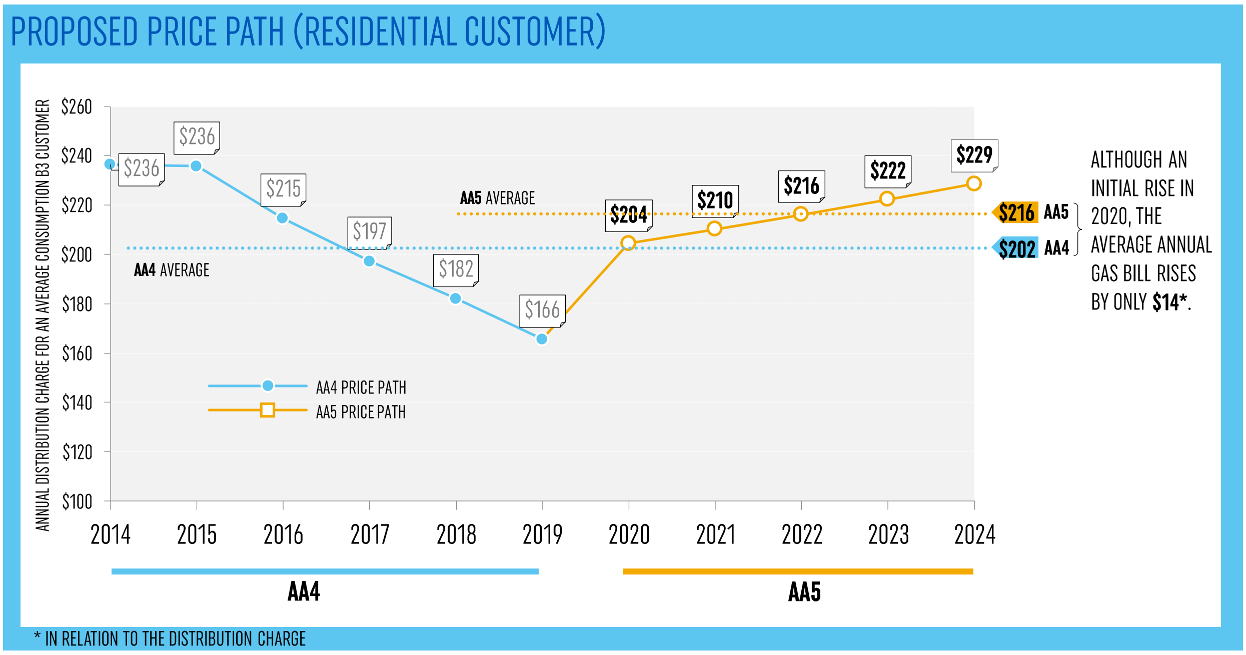
Given this landscape, our commitment for the five years 2020-24 is to continue to focus on the long-term interests of customers by providing a safe, reliable, and affordable gas distribution network while supporting a competitive retail market, enabling growth for Western Australia, and building the foundation for a clean energy future.

Our 2020-24 Plan will:

- Continue to provide a **safe** gas distribution network in accordance with good industry practice, by:
  - Managing our ageing assets to ensure that our network complies with the relevant legislation and operates at an acceptable level of risk. *See Section 12.6.*
  - Investing in the safety of our workforce through targeted programs such as the step-touch mitigation program and through ongoing training. Our workforce has a clear focus on the safety and welfare of our customers and the community.
  - Maintaining our local contact-centre and our 24/7 operational response field crews to allow us to respond promptly to safety incidents raised by the public.

- Maintain **reliable** access to gas by:
    - Investing in the security of supply to support critical parts of the network and reduce the risk of interruption. *See Section 12.7.2.*
    - Reinforcing the network to ensure reliable gas supply is continued as additional customers are connected. *See Section 12.8.2.*
    - Investing in technology to enable better performance of the existing network at peak times and to make the existing network more resilient to damages or failures. *See Section 12.7.4.*
    - Supporting reliability through ongoing replacement, continuous maintenance, and asset protection to prevent outages and damage to our network. *See Sections 12.6 and 12.8.*
- Provide **affordable** access to gas at a price reflecting our underlying efficient costs.
    - Keeping average AA5 charges at a comparable level with average AA4 charges (in real terms). The average distribution charge (nominal, for an average consumption customer) increases between 4% and 11%, compared to inflation over AA4 of 10%. Figure 7.1 outlines the proposed price path for an average residential customer, showing that the average annual charge over AA5 is only $14 higher than it was over AA4. *See Chapter 19.*
    - The distribution charge in nominal terms at the end of 2024 is *less than it was at the start of the AA4 period in 2014 ($229 vs $236 respectively). See Chapter 19.*

**Figure 7.1:** Price path for (B3) residential customers - AA4 to AA5 ($nominal)




- 
    - Investments in IT systems that will allow us to continue to deliver our services efficiently. *See Section 12.9.*
    - To incentivise investment in innovative technologies and adaptation, we are proposing a network innovation scheme for AA5. *See Chapter 17.*
- Support a **competitive retail market** by:
    - Continuing to improve our systems and processes to support larger volumes of customers switching retailers, including upgrading our existing billing system. *See Section 12.9.*
    - Evolving our digital platforms and the omni-channel approach (online systems and apps) to make it easier for customers to interact with us before they are connected to the network, while they are connected, and when they disconnect. *See Section 12.9.*

- Enable the **growth of the Western Australia state economy** by:
  - Connecting over 83,000 new customers (81,000 residential and over 2,000 commercial and industrial) during 2020-24. *See Section 12.8.*
  - Supplying an efficient gas energy source to all our customer segments through our dedicated account managers; supporting industry-leading connection timeframes for new and existing customers.
  - Collaborating with the other utilities to enable the efficient delivery of upgrade works, minimise disruption to residents and businesses during upgrades, and to minimise the cost of the works.
  - Introducing the Development Rebate Scheme to facilitate gas reticulation in new commercial subdivisions. *See Section 23.6.1.*
- Build the **foundation for a clean energy future** by:
  - Ensuring our network designs remain efficient while transitioning to a cleaner energy future through the introduction of renewable gas, e.g. biogas and hydrogen.
  - Investing in systems and processes that allow us to monitor HHV and facilitate differential pricing across the network. *See Section 12.7.4.*

# 8. Pipeline services

**CHAPTER HIGHLIGHTS**

1. We will retain the current reference services into AA5.
2. We will introduce special meter reading as an ancillary reference service in AA5.
3. In certain cases, we will negotiate non-reference services with customers that require services that are different from reference services.

## 8.1 Introduction

Pipeline services on the GDS are delineated into *reference services* and *non-reference services:*

- Reference services describe our services that are likely to be used by a large proportion of our customer base.
- Non-reference services are typically negotiated on a case-by-case basis with customers and are only sought by a small portion of the market.

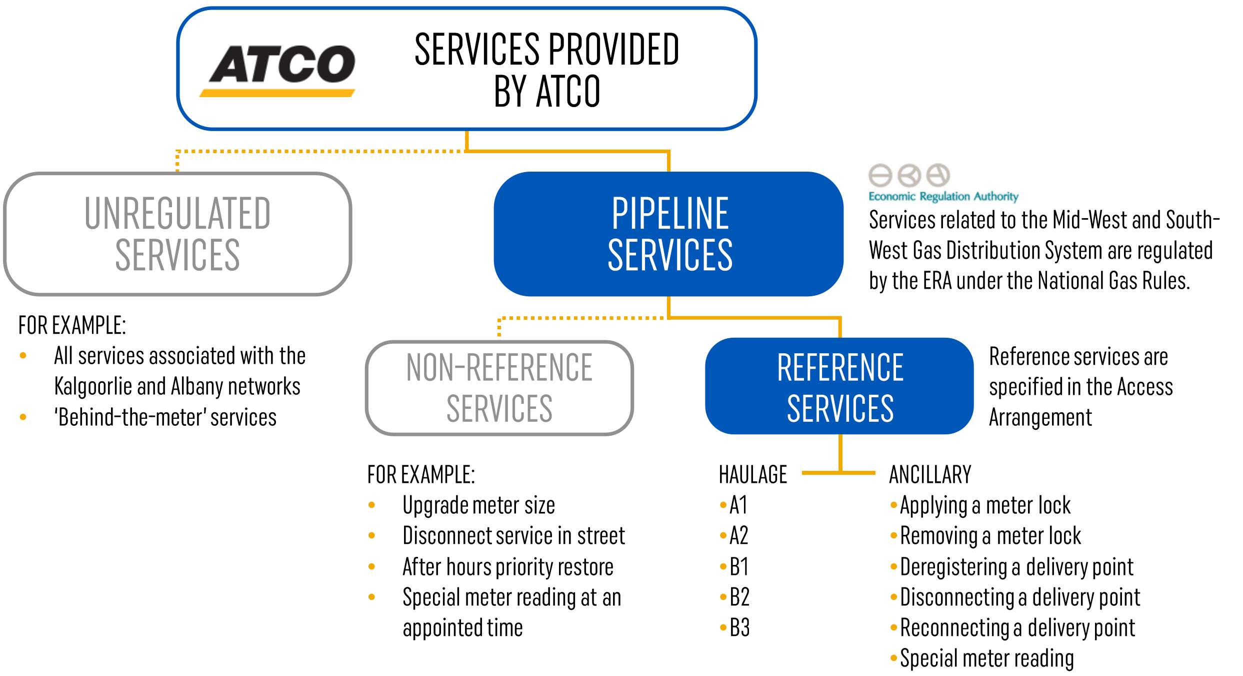
In AA5, we will continue to offer five pipeline services as reference services. These reference services, labelled A1, A2, B1, B2, and B3, are currently offered under AA4 and are unchanged in AA5.

In AA5, we will offer 'special meter reading' as an additional *ancillary reference service* to support the increased retail competition in the Western Australian market. The other five ancillary reference services are substantially the same as those offered by us during AA4.

Details on how these services are proposed to be priced can be found in Chapter 19.

Our proposed service classification for AA5 is illustrated in Figure 8.1.

**Figure 8.1:** Proposed AA5 service classification



## 8.2 Stakeholder engagement

We sought feedback on our Draft Plan regarding our proposed pipeline services. Feedback indicated that stakeholders support our proposed pipeline services and the reclassification of 'special meter reading' to a reference service. The following table summarises the feedback received and our respective responses.

**Table 8.1:** Consideration of stakeholder feedback on pipeline services

| DRAFT PLAN QUESTION | STAKEHOLDER FEEDBACK | OUR RESPONSE |
|---|---|---|
| Is there any additional information you would like on our proposed pipeline services? | No responses received | **N/A** |
| Do you agree with the pipeline services we have proposed? Are there any services not listed that we should be offering? Are there any proposed services that you believe we shouldn't be offering? | **Retailer A** recommends the increased use of *street valves* as part of undertaking a street disconnection at a site. This would create two new charges: a street disconnection fee; and a valve turn-on fee (which should be charged the same as the 'Removing Meter Lock' reference service).<br>These charges would be charged to the user requesting each of these services. Retailer A would like to see these become reference services. | **No change –** ATCO currently provides a disconnection (and subsequent reconnection) at the street service as a *non-reference service* as it is a low volume service (83 in 2016 and 162 in 2017). We will continue to provide this service as a non-reference service in AA5 because we expect it is unlikely to be required by a significant portion of the market in AA5.<br>We will continue to investigate alternative methods to disconnect customers safely and efficiently; including the application of alternative locking devices in some circumstances. This has the potential to further reduce the volume of the 'disconnection at the street' (and subsequent reconnection) service requests in AA5. |
| | Retailer B agrees with our proposal to retain the current AA4 haulage reference services in AA5. | **No change –** We propose that the AA4 haulage reference services are retained in AA5. |
| Do you agree with the re-classification of the 'special meter reading' service to a reference service? | There was general support from retailers:<br>• Retailer A agrees with reclassifying this service, particularly if it provides continuity for all retailers and improved costs for the service.<br>• Retailer B supports the special meter reading as an ancillary reference service, given the increasing number of special meter reading requests related to customer transfers. | **No change** – We propose that the 'special meter reading' service is classified as a reference service for AA5. Further detail on the pricing for the special meter reading can be found in Chapter 19. |

| DRAFT PLAN QUESTION | STAKEHOLDER FEEDBACK | OUR RESPONSE |
|---|---|---|
| | • Retailer C queried the price to be charged for special meter reading. | |

## 8.3 Reference services

Reference services comprise of *haulage* reference services and *ancillary* reference services. The proposed haulage reference services for AA5 are the same as those applying in AA4 (see Table 8.2).

Our haulage reference services relate primarily to the transportation of gas from the transmission pipeline to the customer. Haulage services also include the installation and maintenance of a standard meter, meter reading, and associated data collection and reporting.

**Table 8.2:** AA5 haulage reference services

| REFERENCE SERVICE | DESCRIPTION |
|---|---|
| **A1** | A1 is a pipeline service under which ATCO delivers gas to a user at a delivery point on the network, where the following preconditions were met at the time the user (then a prospective user), submitted an application for the service:<br>• The prospective user is reasonably expected to take delivery of **35 terajoules (TJ) or more** of gas during each year of the haulage contract; and<br>• The prospective user is reasonably expected to require a contracted peak rate of 10 GJ or more per hour; and<br>• The prospective user requests user-specific delivery facilities. |
| **A2** | A2 is a pipeline service under which ATCO delivers gas to a user at a delivery point on the network, where the following preconditions were met at the time the user (then a prospective user), submitted an application for the service:<br>• Either (or both):<br>○ The prospective user is reasonably expected to take delivery of **10 TJ or more of gas, but less than 35 TJ of gas**, during each year of the haulage contract, or is reasonably expected to require a contracted peak rate of less than 10 GJ per hour; and<br>○ An Above 10 TJ Determination[15] was, or was likely to have been, made under the Retail Market Procedures (WA); and<br>• The prospective user requests user specific-delivery facilities. |
| **B1** | B1 is a pipeline service under which ATCO delivers gas to a user at a delivery point on the network, where the following preconditions were met at the time the user (then a prospective user), submitted an application for the service:<br>• Either the prospective user is reasonably expected to take delivery of **less than 10 TJ** of gas during each year of the haulage contract, or is reasonably expected to require a contracted peak rate of less than 10 GJ per hour; and<br>• The prospective user requests user-specific delivery facilities or standard delivery facilities that include a standard meter with a badged capacity of **18 cubic meters per hour ($m^3$/h) or more.** |

[15] Section 139(3) of the Retail Market Procedures (WA) requires the Australian Energy Market Operator (AEMO) to make an Above 10 TJ Determination if, in AEMO's opinion, the gas deliveries to the Delivery Point are likely to exceed 10 TJ in the year immediately following the day of determination. The Retail Market Procedures (WA) are available here: https://www.aemo.com.au/Gas/Retail-markets-and-metering/Market-procedures/Western-Australia

| REFERENCE SERVICE | DESCRIPTION |
|---|---|
| **B2** | B2 is a pipeline service under which ATCO delivers gas to a user at a delivery point on the **medium pressure and low pressure parts of the network** using standard delivery facilities that include a standard meter with a badged capacity of **greater than or equal to 12 $m^3$/h and less than 18 $m^3$/h**. |
| **B3** | B3 is a pipeline service under which ATCO delivers gas to an end-use customer at a delivery point on the **medium pressure and low pressure parts of the network** using standard delivery facilities that include a standard meter with a badged capacity of **less than 12$m^3$/h**.<br>End-use customers who receive B3 reference services consume less than 1 TJ of gas per year and are small use customers as defined in the *National Gas Access (WA) (Local Provisions) Regulations 2009.* |

The proposed ancillary reference services for AA5 are the same as those applying in AA4, with the addition of special meter reading (see Table 8.3).

**Table 8.3:** AA5 ancillary reference services

| REFERENCE SERVICE | DESCRIPTION |
|---|---|
| **Applying a meter lock** | A lock is applied to a valve that comprises part of the delivery facility to prevent gas from being received at the relevant delivery point. This service is available for reference service B2 and B3 users, subject to the suitability of the meter control valve. |
| **Removing a meter lock** | A lock that was applied to a valve to prevent gas from being received at the relevant delivery point is removed. This service is available for reference service B2 and B3 users. |
| **Deregistering a delivery point** | A delivery point is permanently deregistered by removing the delivery facility permanently, removing the delivery point in accordance with the Retail Market Procedures (WA) and removing the delivery point from the delivery point register. This service is available for all reference service users. |
| **Disconnecting a delivery point** | A delivery point is physically disconnected and prevents gas from being delivered to the delivery point. This service is available in respect of delivery points at which a user is provided with reference service B2 or B3. |
| **Reconnecting a delivery point** | The delivery point is reconnected to allow gas to be delivered to the delivery point. This service is available in respect of delivery points at which a user is provided with reference services B2 or B3. |
| **Special meter reading** | An out of cycle reading of a standard meter at the relevant delivery point. This service is available in respect of delivery points at which a user is provided with reference service B1, B2 or B3 with a manually read meter. |

The new reference service, 'special meter reading', is discussed further in Section 8.4.

We believe that our proposed reference services will continue to be required by a large proportion of our customer base and therefore will continue in AA5.

## 8.4 Special meter reading

A 'special meter reading' is a reading of a gas meter that occurs outside of the regular cycle. We have re-classified the special meter reading service from a non-reference service to a reference service in AA5.

This is because it is likely to be sought by a larger proportion of the market in AA5 and received support from retailers in response to our Draft Plan.

During AA4, increased retail competition in the residential gas market has driven up the volume of special meter readings, with a tenfold increase from 12,457 in 2013 to over 119,000 in 2017. We expect this volume to continue into AA5 as increasing numbers of customers change retailers.

However, the 'special meter reading *at an appointed time*' service will remain classified as a non-reference service due to its expected low volumes.

## 8.5 Non-reference services

Occasionally, our customers may require additional services that do not form part of our reference services list. These services are referred to as *non-reference services,* and in such cases, we will negotiate a price directly with the customer.

The forecast costs and demand associated with providing non-reference services are not included in the forecasts presented in this document. We allocate costs between reference and non-reference services in accordance with the method described in our Cost Allocation Method, provided as Attachment 1.3.

# 9. Demand forecast

**CHAPTER HIGHLIGHTS**

1. The 2020-24 demand forecast in this chapter is based on expert advice from Core Energy Group ('**Core**'). Where appropriate, Core has implemented improvements relating to the ERA's feedback received in AA4.
2. Our Draft Plan included *a range* for forecast demand whereas the new Core demand forecast features several improvements. These improvements include a survey of A1 customers, daily weather normalisation, and the inclusion of the most recent customer consumption data for the 2017 calendar year[16].
3. During AA5, the number of customers is forecast to grow at an annual rate of 1.6%. *Consumption per customer* during AA5 is forecast to decline; resulting in a decline in *overall consumption* forecast at an annual rate of 1.1%.
4. We continue to normalise the effect of weather on demand using an effective degree day (**EDD**) method as adopted in AA4. The EDD method incorporates several climatic variables affecting consumption and behaviour of Western Australian gas users, thus achieving increased consumption forecasting accuracy.

## 9.1 Introduction

This chapter outlines our forecast of customer numbers and demand volumes for reference services over AA5. These forecasts inform the AA5 forecast capex, opex, and reference tariffs. The 2020-24 demand forecast in this chapter is based on expert advice from Core Energy Group ('**Core**').

## 9.2 Stakeholder feedback

We sought feedback on our Draft Plan (published in May 2018) regarding our proposed demand forecast. Feedback indicated that stakeholders required further information on our demand forecasts (see Table 9.1).

**Table 9.1:** Demand forecast - stakeholder feedback and our response

| DRAFT PLAN QUESTION | STAKEHOLDER FEEDBACK | OUR RESPONSE |
|---|---|---|
| Do you believe our forecast of new customer connections is reasonable? | Draft Plan gross connections of 93,269 were considered too high in light of market conditions (current and forecast). | **Change:** The revised forecast of 83,410 includes consideration of market conditions and is considered more reasonable. |
| Do you believe our forecast of customer demand is reasonable? | Stakeholders requested further information concerning our forecast method. | **No change:** A detailed description of the demand forecast method is provided in the Core Energy Group Gas Demand Forecast report, see Attachment 9.1. |

[16] The Draft Plan only included annual weather normalisation and data up to 2016.

| DRAFT PLAN QUESTION | STAKEHOLDER FEEDBACK | OUR RESPONSE |
|---|---|---|
| Do you believe ATCO's method to forecast customer numbers and average consumption per customer is reasonable and likely to produce the best estimate? | Stakeholders asked whether we had considered weather trends. | **Change:** The Draft Plan included *annual* weather normalisation. A *daily* weather normalisation analysis has replaced this, as per the Core demand forecast. |
| Are there any demand-related factors you believe we have missed for AA5? Considering our rapidly changing energy environment (including the electricity sector), are there any 'left-field' demand factors that may play a greater role for future AA periods? | Stakeholders requested consideration of customers connected to the gas network who are consuming no gas ('zero-consumption' sites). | **Change:** The Draft Plan did not separately consider zero-volume connections. The projected disconnection of zero-volume customers has been factored in the Core demand forecast. |
| **Other feedback** – special meter reading | The volume of special meter readings is considered somewhat low by some stakeholders in light of high 2017-18 market churn data. | **No Change:** We acknowledge the recently high churn due to increased competition in the gas market. Given the effect on tariffs is likely to be negligible, we have not adjusted this aspect. |

Following consultation on our Draft Plan, Core finalised our demand forecast for AA5. We publicly released the final Core report on the yourgas.com.au website in July 2018 and advised interested stakeholders by email. We then conducted a retailer workshop in mid-July where Core presented a summary of their methodology and findings to retailers (see Section 4.7.2).

The workshop provided an opportunity for retailers to understand the method used to prepare our gas demand forecasts for AA5. Feedback received from retailers indicated they needed to spend more time reviewing the demand forecast outlined in the Core report before they could comment further.

## 9.3 Forecast method and forecast accuracy

Core's demand forecast method considers all recent AA demand forecast proposals, draft decisions, and final decisions. This is a best-practice approach and remains compliant with the NGR. Where appropriate, Core has implemented improvements relating to the ERA's feedback received in AA4.

Our Draft Plan included *a range* for forecast demand whereas the Core demand forecast features several improvements. These improvements include a survey of A1 customers, daily weather normalisation, and the inclusion of the most recent customer consumption data for the 2017 calendar year.

The Core forecast method is a transparent approach, including a demand forecast model that examines all factors that could potentially affect normalised demand. This approach is fundamentally consistent with the method presented by the Australian Energy Market Operator (**AEMO**) in a past National Gas Forecasting Report[17].

We continue to normalise the effect of weather on demand using an effective degree day (**EDD**) method as adopted in AA4. The EDD method incorporates several climatic variables affecting consumption and behaviour of Western Australian gas users, thus achieving increased consumption forecasting accuracy.

17 *ACIL Allen Consulting, Gas Demand Forecasting: A Methodology*. June 2014.

The gas demand forecast has been developed by forecasting the number of connections by tariff class (A1 to B3) and determining the expected average consumption *per connection* in each tariff class. For a detailed description of the method adopted for each tariff class, refer to the Core Gas Demand Forecast in Attachment 9.1.

## 9.4 Historical demand

Historical demand is one of the factors considered in the AA5 demand forecasts. Table 9.4 shows the historical network demand and average customer base for each tariff class over AA4.

**Table 9.2:** AA4 (actual and forecast) demand and average customer base

| TARIFF CLASS | 2014 (JUL-DEC) ACTUAL | 2015 ACTUAL | 2016 ACTUAL | 2017 ACTUAL | 2018 FORECAST | 2019 FORECAST |
|---|---|---|---|---|---|---|
| **A1 TARIFF** | | | | | | |
| Average Customer Base | 73 | 74 | 76 | 76 | 73 | 72 |
| Demand (TJ) | 6,026 | 11,398 | 10,778 | 10,338 | 10,184 | 10,020 |
| **A2 TARIFF** | | | | | | |
| Average Customer Base | 107 | 107 | 102 | 99 | 98 | 97 |
| Demand (TJ) | 972 | 1,854 | 1,820 | 1,814 | 1,770 | 1,718 |
| **B1 TARIFF** | | | | | | |
| Average Customer Base | 1,400 | 1,445 | 1,520 | 1,600 | 1,672 | 1,744 |
| Demand (TJ) | 889 | 1,721 | 1,930 | 1,875 | 1,986 | 2,042 |
| **B2 TARIFF** | | | | | | |
| Average Customer Base | 10,225 | 10,62 | 11,115 | 11,497 | 11,830 | 12,193 |
| Demand (TJ) | 663 | 1,292 | 1,369 | 1,343 | 1,372 | 1,399 |
| **B3 TARIFF** | | | | | | |
| Average Customer Base | 671,182 | 686,911 | 705,513 | 718,911 | 727,270 | 735,731 |
| Demand (TJ) | 5,227 | 9,797 | 10,875 | 9,932 | 10,082 | 10,033 |
| **TOTAL** | | | | | | |
| **Average Customer Base** | **682,986** | **699,160** | **718,325** | **732,182** | **740,943** | **749,836** |
| **Demand (TJ)** | **13,777** | **26,062** | **26,772** | **25,303** | **25,395** | **25,211** |

## 9.5 A1 and A2 demand forecast

↓1.9%
DEMAND

A1 and A2 demand has declined from 13,442 TJ in 2014 to 12,153 TJ in 2017 (or -3.3% p.a.). We expect this trend to continue and forecast a decline of -1.9% p.a. over AA5.

The A1 and A2 forecast has been developed by forecasting four customer groupings, described in Table 9.3:

**Table 9.3:** A1 and A2 forecasting customer groups

| SURVEY TYPE | DESCRIPTION | A1 FORECAST | A2 FORECAST |
|---|---|---|---|
| **Surveyed customers** | GJ Maximum Hourly Quantity (**MHQ**) and Annual Contract Quantity (**ACQ**) is forecast according to known | 35 survey responses were received representing more than | No survey process was undertaken. |

| SURVEY TYPE | DESCRIPTION | A1 FORECAST | A2 FORECAST |
|---|---|---|---|
| | load changes obtained via responses received from a direct survey of customers. | 40% of our A1 customer base. | |
| **Gross Value Add customers** | Customers that belong to a particular segment (per ANZSIC classification) that have a demonstrated statistical relationship between gas demand and output (measured by ABS' Gross Value Add) | Manufacturing only (applies to 23 continuing customers as an additional 23 manufacturing customers were forecast using a customer survey). | 48 continuing customers. |
| **Weather Normalised Trend** | Several sectors that exhibited a clear weather-induced consumption pattern | 11 customers, various sectors | 42 customers, various sectors. |
| **Average Trend Customers** | Customers who did not fall into the above groupings have an ACQ forecast according to the observed historical trend | Mining, Administrative and Support Services, Transport, Postal, and Warehousing customers | Mining, Construction, Administrative and Support Services, Transport, Postal, and Warehousing customers. |

Figure 9.1, Figure 9.2, and Table 9.4 outline the historical and forecast total demand for A1 and A2 customers respectively.

**Figure 9.1:** Historical and forecast total A1 demand

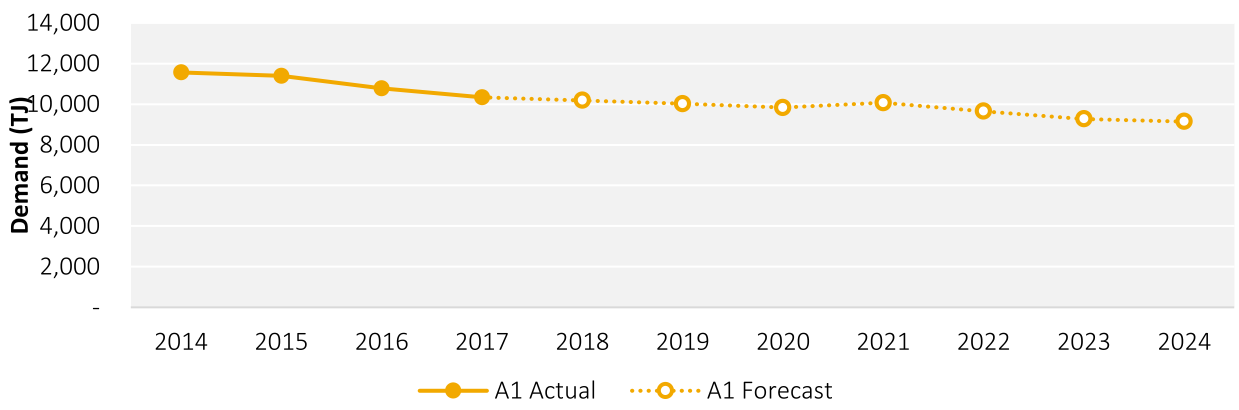


**Figure 9.2:** Historical and forecast total A2 demand

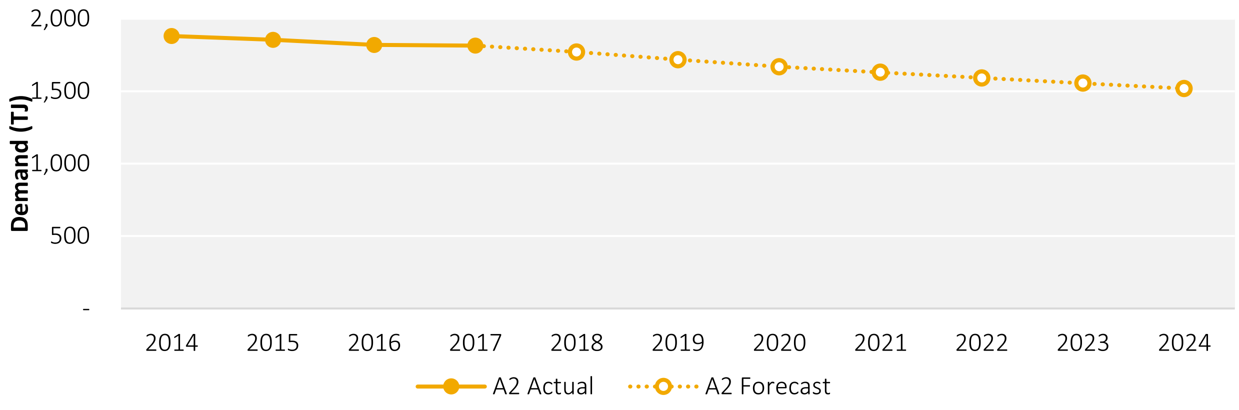



**Table 9.4:** AA5 Forecast average customer base and demand for A1 and A2 (industrial) customers

| TARIFF CLASS | 2020 | 2021 | 2022 | 2023 | 2024 | CAGR* |
|---|---|---|---|---|---|---|
| A1 TARIFF | | | | | | |
| Average Customer Base | 72 | 72 | 71 | 70 | 69 | -1.1% |
| Demand (TJ) | 9,828 | 10,066 | 9,649 | 9,270 | 9,143 | -1.8% |
| A2 TARIFF | | | | | | |
| Average Customer Base | 96 | 96 | 96 | 96 | 96 | 0.0% |
| Demand (TJ) | 1,669 | 1,630 | 1,592 | 1,555 | 1,519 | -2.3% |

* Compound Annual Growth Rate

## 9.6 B1 and B2 demand forecast

**↑1.3%**
DEMAND

B1 and B2 demand has increased from 2,899 TJ in 2014 to 3,218 TJ in 2017 (or 3.5% p.a.). We expect this trend to continue and forecast an increase of 1.3% p.a. over AA5.

The B1 and B2 demand forecast is a product of the *connections* and *demand per connection* forecasts. We have considered historical trends as well as forecast drivers of demand.

- **Connections**
  Our total connections forecast is based on historical statistical relationships between real Gross State Product (GSP), business numbers, and net or total connections. The forecast connection growth rate is slower than the historical period, due to a lower GSP growth forecast that followed a 2016/17 correction following the WA mining boom (2015).
- **Demand per connection**
  Demand per connection is forecast to remain relatively flat to slightly declining over AA5. The B1 and B2 forecast includes weather normalisation and price elasticity effects (gas and electricity). However, the analysis concluded that the relationship between economic variables and B1 and B2 customer demand is unreliable and not statistically significant. Such factors (such as state output) are drivers of connections, but demand per connection does not demonstrate a robust statistical relationship.

Our demand forecast for B1 and B2 customers is shown in Figure 9.3, Figure 9.4, and Table 9.5.

**Figure 9.3:** Historical and forecast total B1 demand

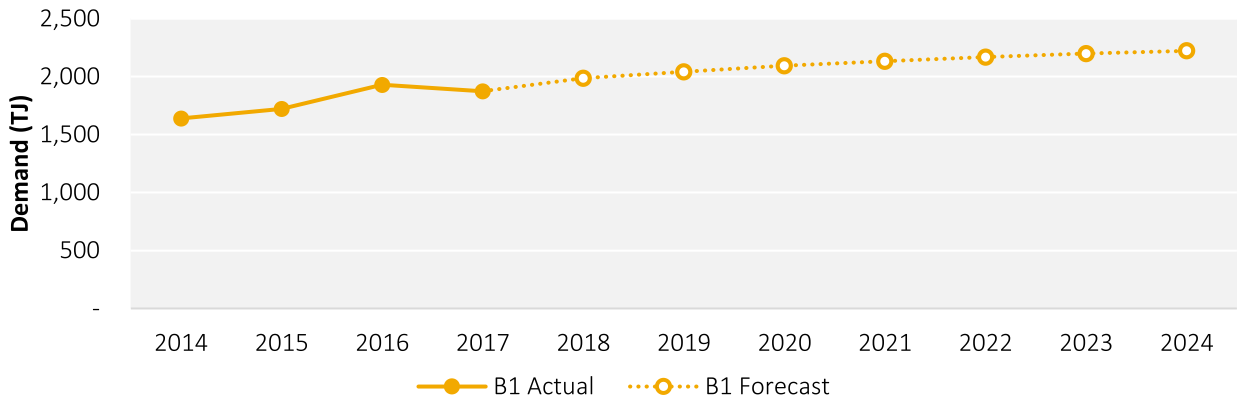



**Figure 9.4:** Historical and forecast total B2 demand

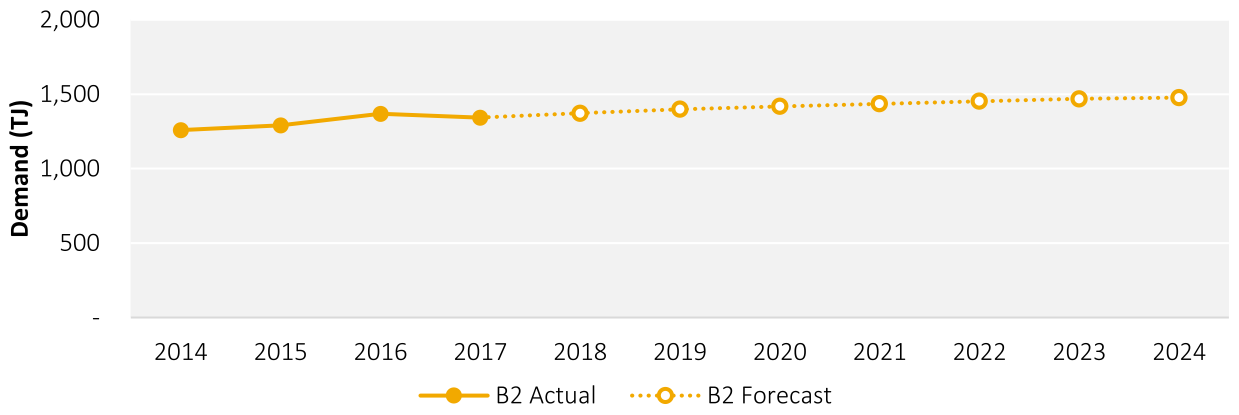



**Table 9.5:** AA5 Forecast average customer base and demand for B1 and B2 (commercial) customers

| TARIFF CLASS | 2020 | 2021 | 2022 | 2023 | 2024 | CAGR* |
|---|---|---|---|---|---|---|
| B1 TARIFF | | | | | | |
| Average Customer Base | 1,816 | 1,885 | 1,949 | 2,010 | 2,069 | 3.3% |
| Demand (TJ) | 2,094 | 2,133 | 2,168 | 2,200 | 2,223 | 1.5% |
| B2 TARIFF | | | | | | |
| Average Customer Base | 12,527 | 12,850 | 13,190 | 13,528 | 13,850 | 2.5% |
| Demand (TJ) | 1,419 | 1,436 | 1,453 | 1,469 | 1,477 | 1.0% |

* Compound Annual Growth Rate

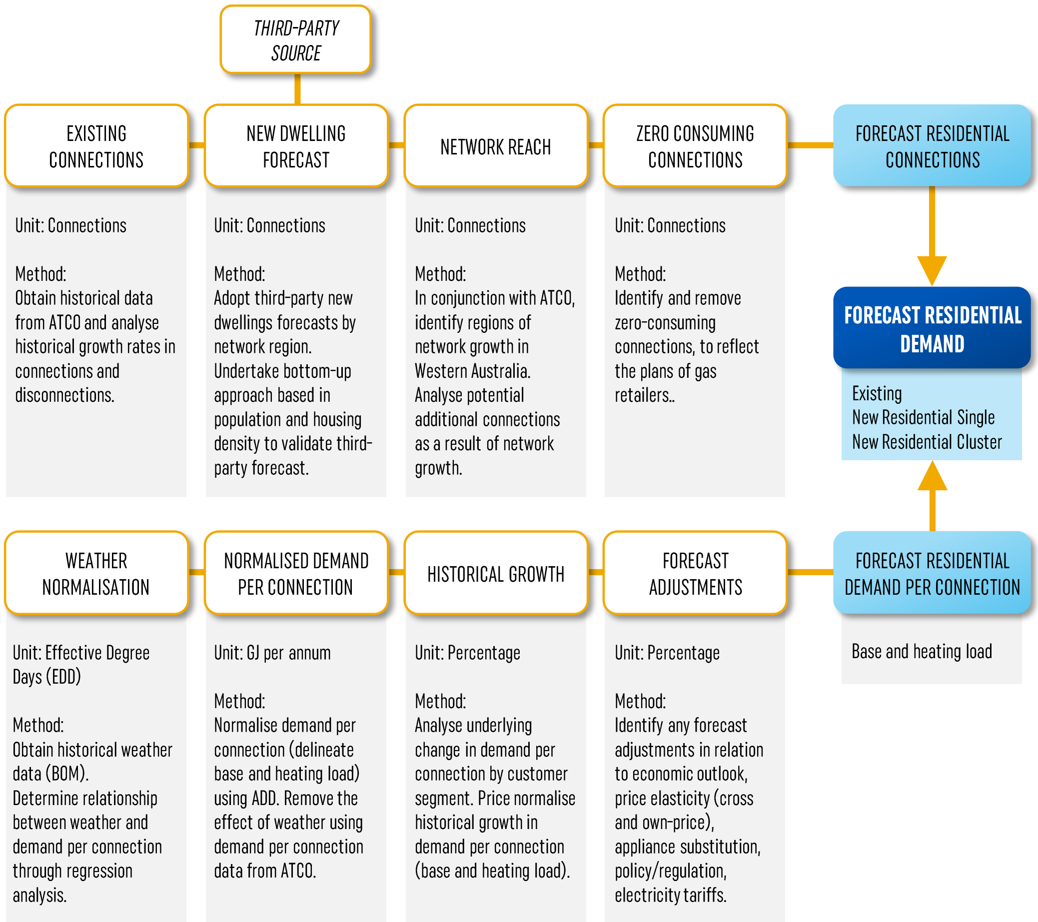
## 9.7 B3 demand forecast

↓1.2%
DEMAND

B3 demand has increased from 9,580 TJ in 2014 to 9,932 TJ in 2017 (or 1.2% p.a.). We have forecast a decrease of 1.2% p.a. over AA5, resulting from a decline in average usage attributed to increasingly efficient appliances and reducing dwelling sizes. The B3 demand forecast is a product of the forecast of connections and demand per connection.

The approach used to derive the B3 demand forecast is outlined in Figure 9.5.

**Figure 9.5:** B3 demand forecast method[18]




We have considered historical trends as well as forecast drivers of demand: *connections* and *demand per connection.*

- **Connections**

  The customer base is expected to grow at 1.6% p.a. This growth rate is reflective of forecast population growth and dwelling completions for Perth through to 2024. Our forecast also includes consideration of 5,500 zero-volume gas users disconnecting in the near future.

- **Demand per connection**

  On a 'weather-normalised' basis, average demand per connection is forecast to decline from 13.9 GJ per customer in 2017 to 11.7 GJ per customer in 2024 at a rate of 2.4%[19]. This rate is consistent with the 2.2% p.a. decline experienced from 2012 to 2017 and reflects the experience of other Australian gas networks. This decline can be attributed to more efficient gas appliances (e.g. instant hot-water systems), smaller household sizes and increasing competition from alternative energy sources.

Our volume demand forecast for B3 customers is shown in Figure 9.6 and Table 9.6.

18 *Source:* Core Energy

19 Based on Core report data, which uses end of period customer numbers to calculate average consumption.

**Figure 9.6:** Historical and forecast total B3 demand

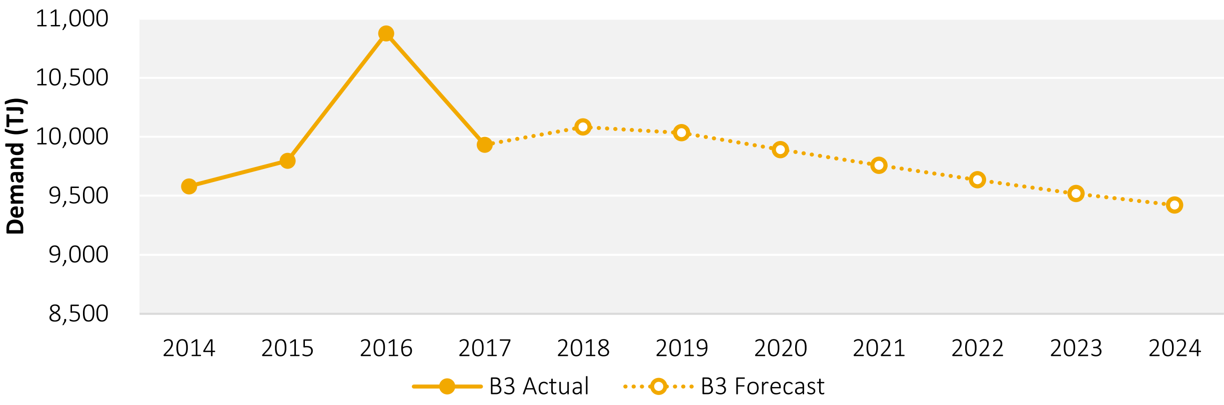



**Table 9.6:** AA5 Forecast average customer base and demand for B3 (residential) customers

| TARIFF CLASS | 2020 | 2021 | 2022 | 2023 | 2024 | CAGR* |
|---|---|---|---|---|---|---|
| B3 TARIFF | | | | | | |
| Average Customer Base | 747,479 | 759,437 | 771,652 | 784,165 | 796,954 | 1.6% |
| Demand (TJ) | 9,891 | 9,758 | 9,634 | 9,518 | 9,421 | -1.2% |

* Compound Annual Growth Rate

## 9.8 Overall demand forecast

Our overall demand forecast is shown in Table 9.7.

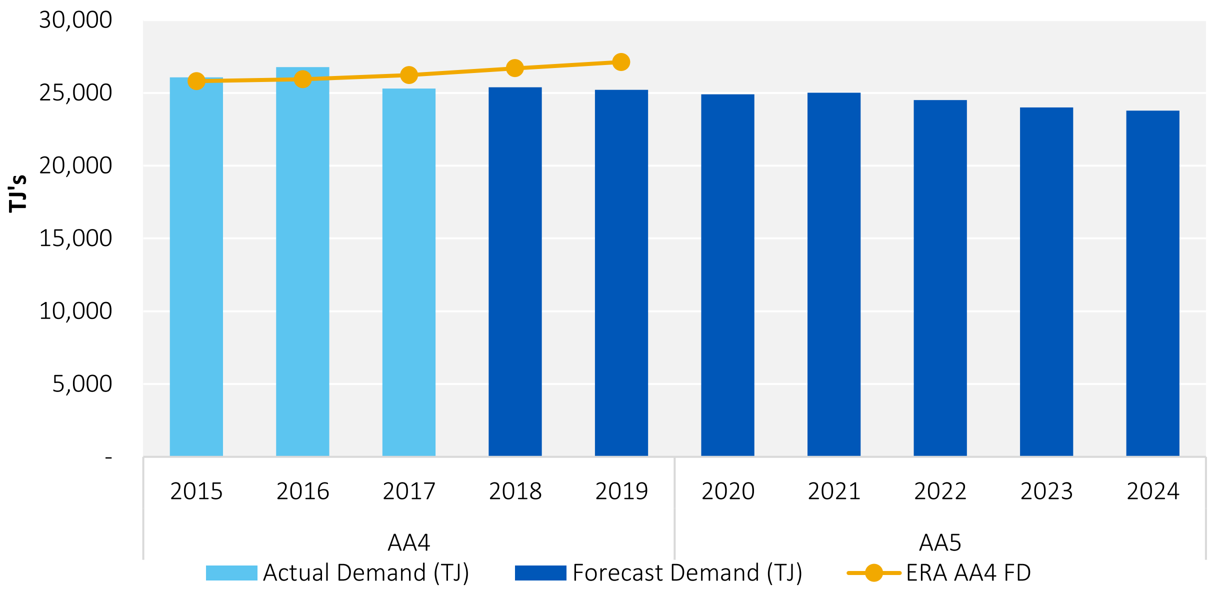
**Table 9.7:** Overall AA5 average customer base and demand forecasts

| TARIFF CLASS | 2020 | 2021 | 2022 | 2023 | 2024 | CAGR* |
|---|---|---|---|---|---|---|
| A1 TARIFF | | | | | | |
| Average Customer Base | 72 | 72 | 71 | 70 | 69 | -1.1% |
| Demand (TJ) | 9,828 | 10,066 | 9,649 | 9,270 | 9,143 | -1.8% |
| A2 TARIFF | | | | | | |
| Average Customer Base | 96 | 96 | 96 | 96 | 96 | 0.0% |
| Demand (TJ) | 1,669 | 1,630 | 1,592 | 1,555 | 1,519 | -2.3% |
| B1 TARIFF | | | | | | |
| Average Customer Base | 1,816 | 1,885 | 1,949 | 2,010 | 2,069 | 3.3% |
| Demand (TJ) | 2,094 | 2,133 | 2,168 | 2,200 | 2,223 | 1.5% |
| B2 TARIFF | | | | | | |
| Average Customer Base | 12,527 | 12,850 | 13,190 | 13,528 | 13,850 | 2.5% |
| Demand (TJ) | 1,419 | 1,436 | 1,453 | 1,469 | 1,477 | 1.0% |
| B3 TARIFF | | | | | | |
| Average Customer Base | 747,479 | 759,437 | 771,652 | 784,165 | 796,954 | 1.6% |
| Demand (TJ) | 9,891 | 9,758 | 9,634 | 9,518 | 9,421 | -1.2% |
| **TOTAL** | | | | | | |
| **Average Customer Base** | **761,990** | **774,341** | **786,958** | **799,867** | **813,038** | **1.6%** |
| **Demand (TJ)** | **24,901** | **25,023** | **24,496** | **24,011** | **23,782** | **-1.1%** |

* Compound Annual Growth Rate

Total demand is forecast to decline from 25,303 TJ in 2017 to 23,782 TJ by 2024. Figure 9.7 illustrates the annual forecast volume over AA4 and AA5 compared to the ERA's AA4 Final Decision.

**Figure 9.7:** Actual and forecast demand for all customers




## 9.9 Pipeline usage

The historical and forecast average, minimum, and maximum demand per day for AA5 is shown in Figure 9.8.

**Figure 9.8:** Actual and forecast average demand per day (TJ) (2014 to 2024)

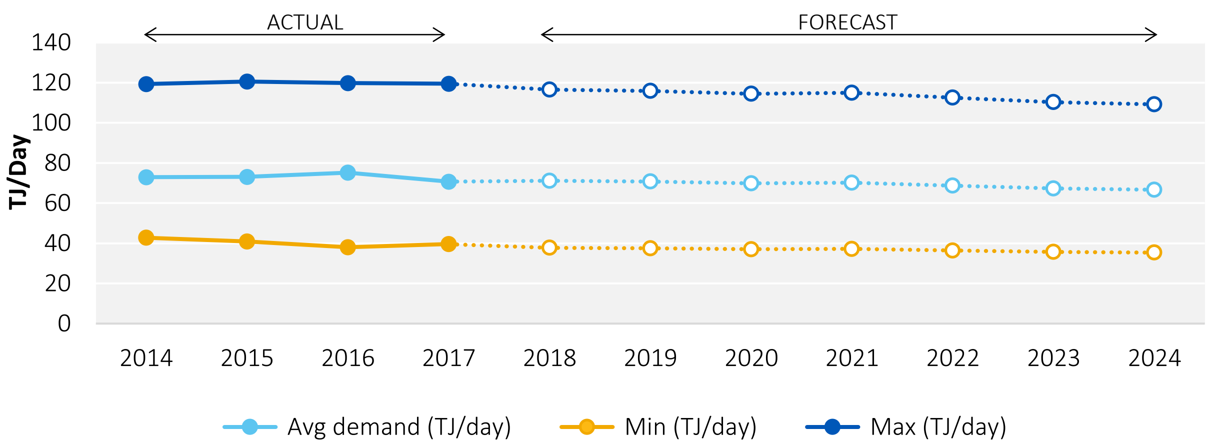



Table 9.8 details the historical minimum, maximum, and average daily demand on the network over AA4.

**Table 9.8:** AA4 Actual and forecast average demand per day (TJ)

| DEMAND | 2014 (JUL-DEC) ACTUAL | 2015 ACTUAL | 2016 ACTUAL | 2017 ACTUAL | 2018 FORECAST | 2019 FORECAST |
|---|---|---|---|---|---|---|
| Average | 78 | 73 | 75 | 71 | 71 | 71 |
| Minimum | 44 | 41 | 38 | 40 | 38 | 38 |
| Maximum | 118 | 121 | 120 | 119 | 117 | 116 |

## 9.10 Forecast demand for ancillary services

Ancillary services across all categories relate mainly to B3 connections. As a result, the forecast level of ancillary services is correlated to the forecast growth in B3 customers of 1.6% p.a. as shown in Table 9.9.

**Table 9.9:** AA5 Forecast demand for ancillary services

| ANCILLARY SERVICE | 2020 | 2021 | 2022 | 2023 | 2024 | CAGR* |
|---|---|---|---|---|---|---|
| Applying a Meter Lock | 8,900 | 9,042 | 9,188 | 9,338 | 9,490 | 1.6% |
| Removing a Meter Lock | 7,589 | 7,711 | 7,835 | 7,963 | 8,093 | 1.6% |
| Deregistering a Delivery point | 2,240 | 2,276 | 2,313 | 2,350 | 2,389 | 1.6% |
| Disconnecting a Delivery Point | 3,461 | 3,517 | 3,574 | 3,632 | 3,691 | 1.6% |
| Reconnecting a Delivery Point | 2,488 | 2,528 | 2,569 | 2,611 | 2,653 | 1.6% |
| Special Meter Reading | 96,436 | 97,980 | 99,563 | 101,183 | 102,838 | 1.6% |

* Compound Annual Growth Rate

## 9.11 Forecast length of mains

The growth in the length of mains relate primarily to the growth in B3 customer connections and the average lot width of 12 metres. As a result, the forecast length of mains is correlated to the forecast growth in B3 customers of 1.6% p.a. as shown in Table 9.10:

**Table 9.10:** AA5 forecast mains length (km): 2020-24

| | 2020 | 2021 | 2022 | 2023 | 2024 | CAGR* |
|---|---|---|---|---|---|---|
| Mains length | 14,411 | 14,619 | 14,837 | 15,054 | 15,299 | 1.5% |

* Compound Annual Growth Rate

# 10. Key performance indicators

**CHAPTER HIGHLIGHTS**

1. Customers have stated that they were satisfied with the current reliability and service levels of their gas supply.
2. We will continue to adopt the AA4 KPIs throughout AA5 with updated targets to reflect our recent performance.
3. We have incorporated an 'asset health' KPI into AA5 to allow customers to see the changes in asset health over the period.
4. Reflecting our customers' preferences for maintaining current levels of service, we have set the targets for the KPIs based on the simple average of our performance over the past five years.

## 10.1 Introduction

We have selected eight key performance indicators (**KPI**s) that reflect the performance of the network in delivering haulage services sought by our customers and are also important drivers for AA5 capex and opex. These KPIs are categorised into three groups; *customer service*, *network integrity*, and *expenditure*. The customer service KPIs and unaccounted for gas (**UAFG**) rates are reported to the ERA annually as required under our distribution licence.

We have acted on the ERA's AA4 Final Decision and developed an 'asset health' KPI for use as a new indicator for AA5.

## 10.2 Stakeholder engagement

Customers have told us that they want us to maintain the excellent level of service and reliability that we currently provide. Only a couple of participants in our workshops said that they may consider paying more for increased service or less for decreased service.

We have incorporated this into the KPIs for AA5 by targeting our AA5 expenditure program to maintain our average service performance over the past five years. We are not seeking to increase or decrease our level of service over AA5.

We sought feedback on our Draft Plan regarding our proposed KPIs. Feedback indicated that stakeholders support our proposed KPIs. The following table summarises the feedback received and our respective response.

**Table 10.1:** Consideration of stakeholder feedback on KPIs

| DRAFT PLAN STAKEHOLDER QUESTION | STAKEHOLDER FEEDBACK | OUR RESPONSE TO FEEDBACK ON OUR DRAFT PLAN |
|---|---|---|
| Do you believe our KPIs provide an adequate measure of performance? | Retailer B agrees with the KPIs proposed by ATCO and notes the additional asset health KPI. | **No change** – We have maintained the proposed AA5 KPIs with updated targets for the expenditure KPIs to link to the updated AA5 expenditure forecasts. |

| DRAFT PLAN STAKEHOLDER QUESTION | STAKEHOLDER FEEDBACK | OUR RESPONSE TO FEEDBACK ON OUR DRAFT PLAN |
|---|---|---|
| Have we set our targets correctly? Do the targets ensure we are sufficiently maintaining our current performance? | Retailer B commented that the proposed KPIs need to accurately reflect any changes in operating and capital expenditure in AA5.<br>Retailer A notes that the UAFG targets are lower than the three Victorian gas distribution networks and queries if ATCO will publish actual UAFG rates against benchmark rates each year for the previous period. | **Change** – We have updated the targets for the expenditure KPIs to link to the updated AA5 expenditure forecasts.<br>We have published the actual UAFG rates compared to the AA4 benchmark in Table 5.1 and Figure 10.6. |
| Are there any performance measures that you think we have missed? | No responses received. | **No change** |

## 10.3 Method to set AA5 targets

We have set our AA5 KPI targets by:

- **Using current performance**: The customer service and network integrity KPIs use the simple average of our service performance over the past five years. We believe the past five years is representative of the performance that customers are seeking into AA5. The five-year average moderates the effect of events outside of our control such as weather.
- **Using expected performance in 2024**: For the new asset health index KPI, we have set the AA5 targets to reflect the level of performance expected in 2024. This KPI allows customers to see the changes in asset health over the period.
- **Aligning with AA5 forecast expenditure**: The expenditure KPIs have been calculated consistent with our expenditure forecasts using the forecasts of opex, customer numbers, and km of mains over AA5. The UAFG KPI targets have been set based on volume demand forecasts and historical trends.

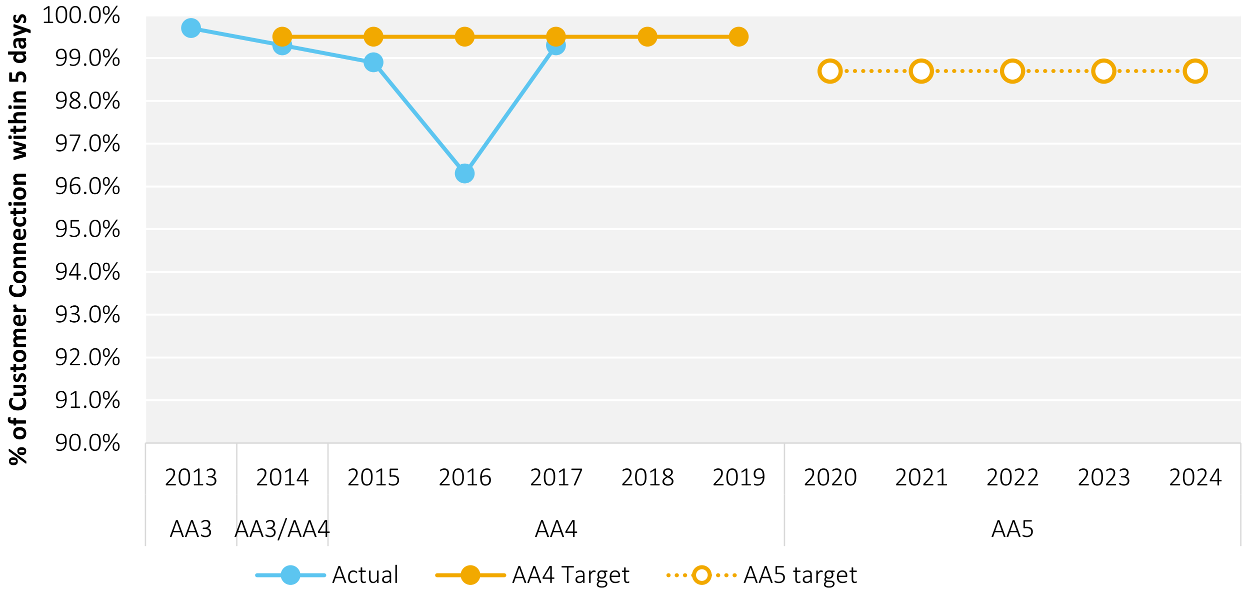
In the following section, we detail the method to set each KPI.

### 10.3.1 Customer service KPIs

1. **Domestic customer connections within five business days (%)**:

   Reporting against this KPI will help us to maintain connection times within customers' expected timeframes despite the forecast increase in connections. Figure 10.1 shows our performance against this indicator during AA4 and the target performance over AA5.

**Figure 10.1:** Domestic customer connections within 5 business days (2013 to 2024)

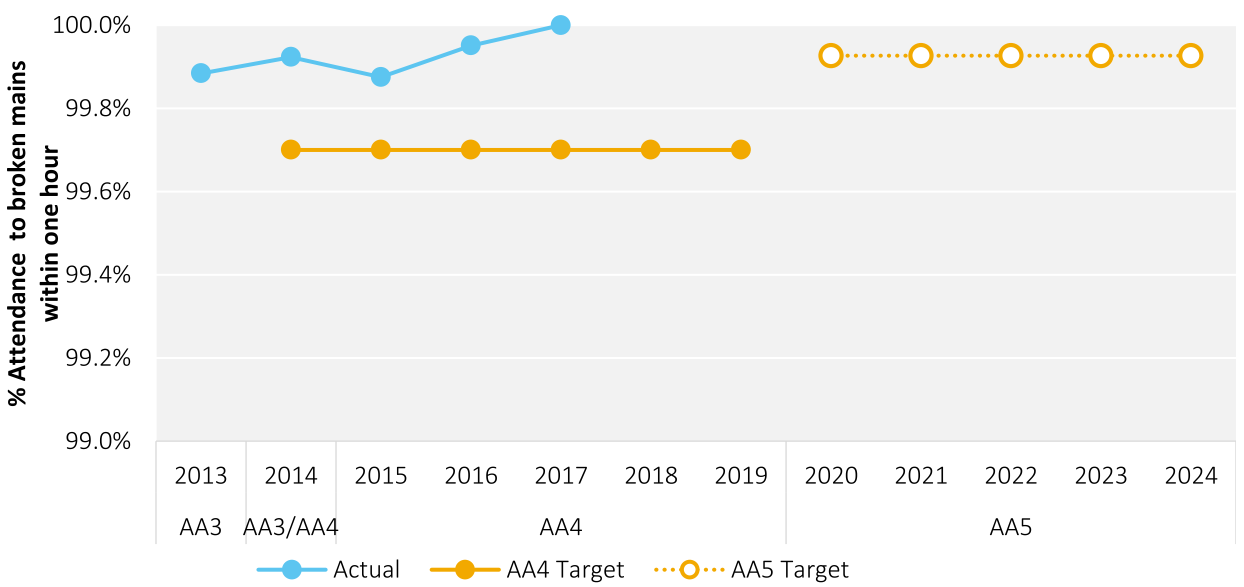



2. **Attendance to broken mains and services within one hour (%)** and **attendance to loss of gas supply within three hours (%)**:

   To ensure the safety of the public and customers connected to the network, we must respond to broken mains and services and loss of gas supply promptly, and within the prescribed KPI timeframes contained in our Safety Case[20]. Reporting against these KPIs will maintain a high standard of fault response and safety performance.

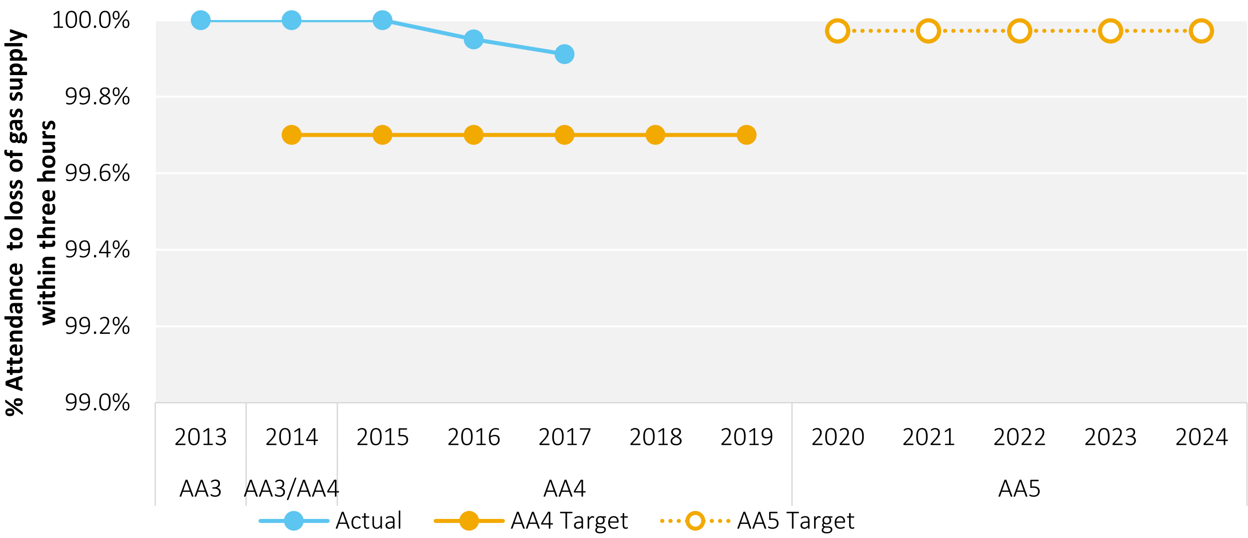
   Figure 10.2 and Figure 10.3 show our performance against these indicators during AA4 and the target performance over AA5.

**Figure 10.2:** Attendance to broken mains and services within one hour (2013 to 2024)




[20] ATCO Gas Australia, *Gas Distribution System Safety Case*, December 2017

**Figure 10.3:** Attendance to loss of gas supply within three hours (2013 to 2024)




## 10.3.2 Network integrity KPIs

1. **Asset Health Index**:

As part of the ERA's AA4 Final Decision, we were required to identify an *asset health KPI* for use in AA5. The purpose of this KPI (the '*Asset Health Index*') is to demonstrate the value of proposed asset expenditure to our customers regarding improved asset health.

In developing the Asset Health Index, we considered:

- what information was measured and reported on in AA4;
- how the index would complement the existing KPIs; and
- whether the index was easily understandable.

The index is based on the weighted average of the index scores for unplanned System Average Interruption Duration Index (**SAIDI**), unplanned System Average Interruption Frequency Index (**SAIFI**), mains leaks, service leaks, and meter leaks. The index score calculation is:

$$Index_n = 200 - \left(\frac{Actual_n}{Target_{2024}}\right) \cdot 100$$

We have set the target performance for each parameter to reflect the expected level of performance in 2024 to enable the Asset Health Index to demonstrate the value of the proposed asset expenditure over AA5 (see Table 10.2).

**Table 10.2:** Asset Health Index parameters

| PARAMETER | DESCRIPTION | WEIGHTING | $\text{TARGET}_{2024}$ |
|---|---|---|---|
| Unplanned SAIDI | Total duration of sustained interruptions in a year | 25% | 1.7877 |
| Unplanned SAIFI | Total number of sustained interruptions in a year | 25% | 0.0041 |
| Main leaks | Leaks pa / km | 30% | 0.0282 |
| Service leaks | Leaks pa / service | 15% | 0.0102 |
| Meter leaks | Leaks pa / meter | 5% | 0.0003 |

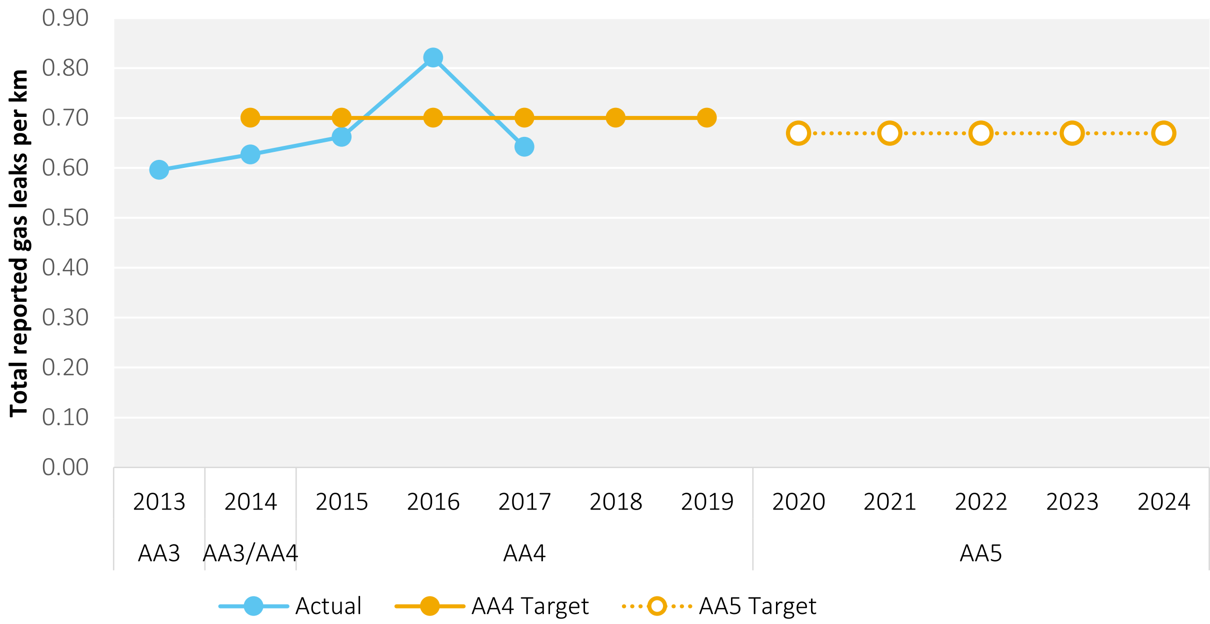
Australian Gas Networks (Victoria and Albury) and AusNet have adopted a similar index for their gas distribution networks.

2. **Total public reported gas leaks per km of main**:

   *'Public* reported gas leaks' is an existing KPI that reflects the performance of the network and our maintenance activities.

Figure 10.4 shows our performance against this indicator during AA4 and our target performance over AA5.

**Figure 10.4:** Total public reported gas leaks per km of main (2013 to 2024)

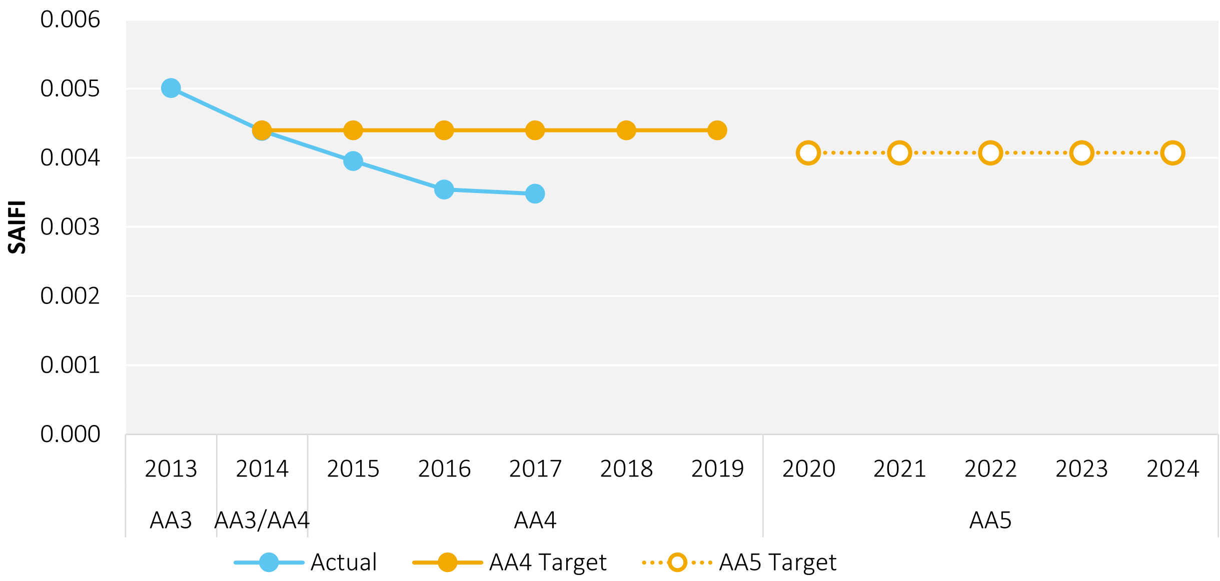



3. **SAIFI (System Average Interruption Frequency Index)**:

   SAIFI is an industry accepted measure for reliability; indicating the average number of interruptions that a customer would experience in a year. During AA5, we will continue to invest in the network, including the installation of high pressure pipelines, interconnections, and associated pressure reduction infrastructure to maintain reliability for customers.

   Figure 10.5 shows our performance against this indicator during AA4 and our target performance over AA5.

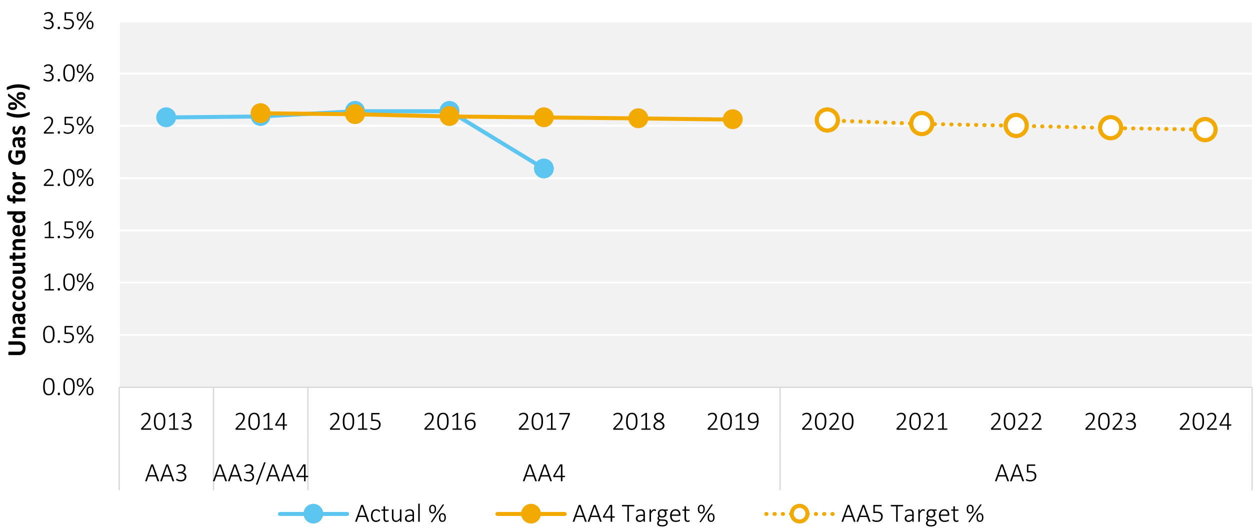
**Figure 10.5:** System average interruption frequency index (SAIFI) (2013 to 2024)




4. **UAFG - rolling 12 months (%)**:

   UAFG is attributable to both leakage in the network and measurement error. UAFG makes up part of the overall cost of providing services. Reporting against this KPI will help us maintain our commitment to reducing UAFG. Figure 10.6 shows our performance against this indicator during AA4. In late 2016 an error in third-party transmission gas measurement occurred, causing an error in the measured UAFG amount. This error over-inflated our UAFG reductions, hence the low UAFG value in 2017. We have developed a UAFG Strategy and Pricing Forecast (see Attachment 11.2) that details our historical and forecast UAFG, providing further detail into our forecast KPI below.

**Figure 10.6:** UAFG (2013 to 2024)



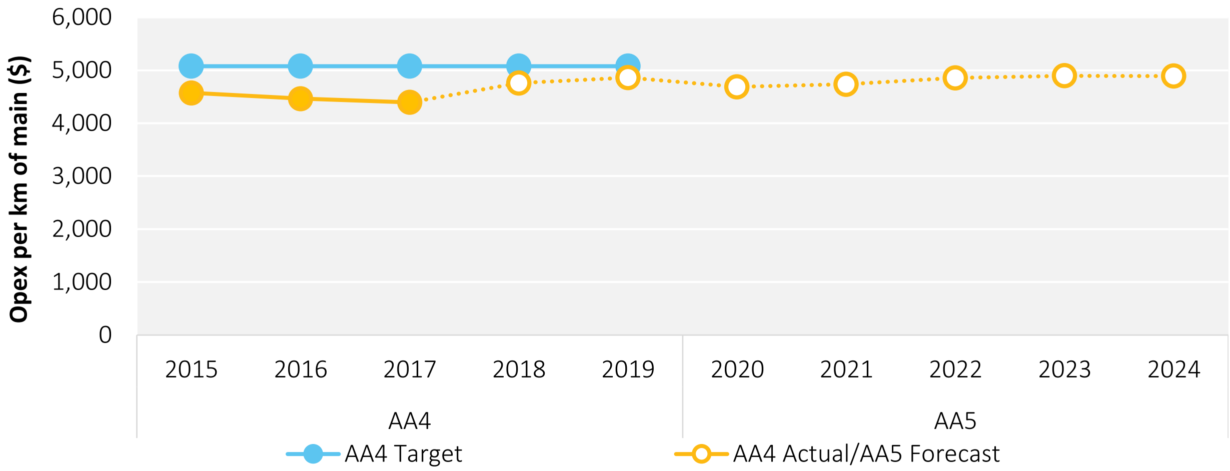
### 10.3.3 Expenditure KPIs

For our Expenditure KPIs, we have chosen *opex per km of main* and *opex per customer connection*. These KPIs ensure that our measures of efficiency include the additional operating costs associated with additional kilometres of network and additional customers.

1. **Opex per km of main**

   Opex per km is an existing KPI that normalises performance. The opex per km over AA4 and our expected performance for AA5 is shown in Figure 10.7.

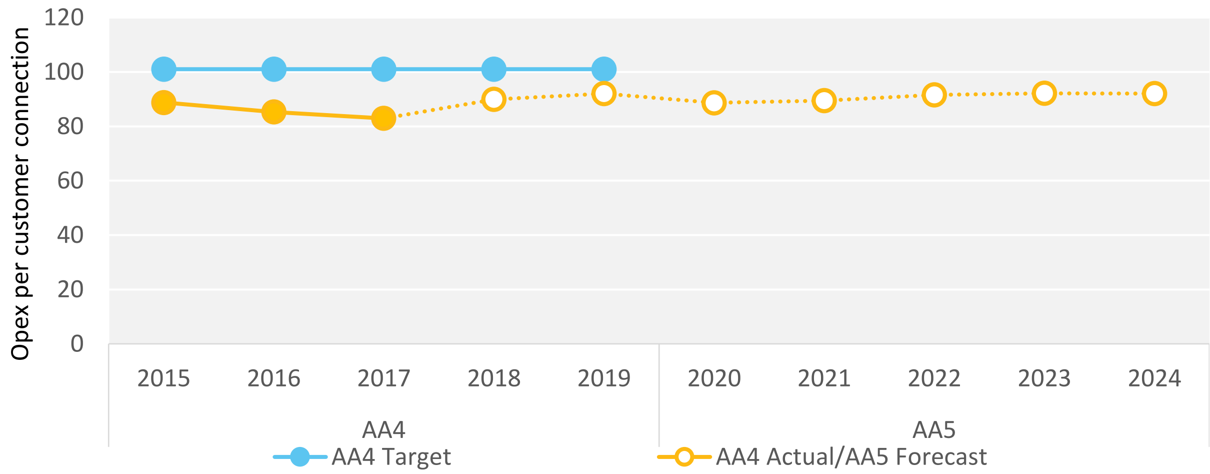
**Figure 10.7:** Opex per km of main (2015 to 2024) ($ real as at 31 December 2019)




2. **Opex per customer connection**

   The opex per customer connection is an existing KPI that normalises performance. The opex per customer connection over AA4 and our target performance for AA5 is shown in Figure 10.8.

**Figure 10.8:** Opex per customer connection (2015 to 2024) ($ real as at 31 December 2019)



## 10.4 AA5 Key Performance Indicators

Table 10.3 and Table 10.4 describe the KPIs and AA5 target performance level.

**Table 10.3:** AA5 KPI targets by year

| KPI | DESCRIPTION | AA5 TARGET |
|---|---|---|
| **CUSTOMER SERVICE** | | |
| **Domestic customer connections within five business days** | The percentage of new customer connections to established domestic dwellings on the distribution network provided within five business days (the applicable regulated time limit) | >98.7% |
| **Attendance to broken mains and services within one hour** | The percentage of attendance to broken mains and services within one hour of the service request being received. | >99.9% |
| **Attendance to loss of supply within three hours** | The percentage of attendance to loss of gas supply within three hours of the service request being received. This indicator is included in our Safety Case[21] and is covered by the Guarantee Service Level scheme. | >99.9% |
| **NETWORK INTEGRITY** | | |
| **Asset Health Index** | An index based on unplanned SAIDI, unplanned SAIFI, mains leaks, service leaks, and meter leaks | 100 |
| **Total public reported gas leaks per kilometre of main** | Total number of confirmed gas leaks reported by the public (excluding third-party damage) per kilometre of main per year | <0.65 |
| **SAIFI** | The number of supply interruptions experienced by the average customer as a result of sustained unplanned interruptions, calculated as (sum of the number of customers interrupted) / (number of customers served) | <0.0041 |
| **UAFG Rate** | UAFG is the difference between the measurement of the quantity of gas *delivered into* the gas distribution system in each period and the measurement of the quantity of gas *delivered from* the gas distribution system during that period. | See Table 10.4 |
| **EXPENDITURE** | | |
| **Opex per km of main** | The total opex per year divided by the total km of main | See Table 10.4 |
| **Opex per customer connection** | The total opex per year divided by the total number of customer connections | See Table 10.4 |

21 ATCO Gas Australia, *Gas Distribution System Safety Case*, December 2017

**Table 10.4:** AA5 opex KPI targets by year

| KPI | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|
| **UAFG Rate** | 2.55% | 2.52% | 2.50% | 2.48% | 2.46% |
| **Opex per km of main ($ 2019)** | $4,687 | $4,736 | $4,855 | $4,894 | $4,889 |
| **Opex per customer connection ($ 2019)** | $89 | $89 | $92 | $92 | $92 |

Our AA5 forecast opex allows us to continue our performance against customer service KPIs. This includes maintaining our current level of 24/7 emergency response capability and attendance to broken mains and loss of supply events at the level delivered over AA4.

We expect to maintain our leadership position as one of the lowest cost providers of natural gas in Australia.

# 11. Forecast operating expenditure

**CHAPTER HIGHLIGHTS**

1. Our opex forecast has been developed using both the base-step-trend method and specific forecasting methods.
2. We forecast opex of $357 million during AA5, compared to a forecast $355 million by the end of AA4.
3. We have the lowest opex per customer compared to our peers.

## 11.1 Introduction

ATCO incurs opex to operate and maintain the network for our customers, respond to publicly reported gas leaks and read customer meters.

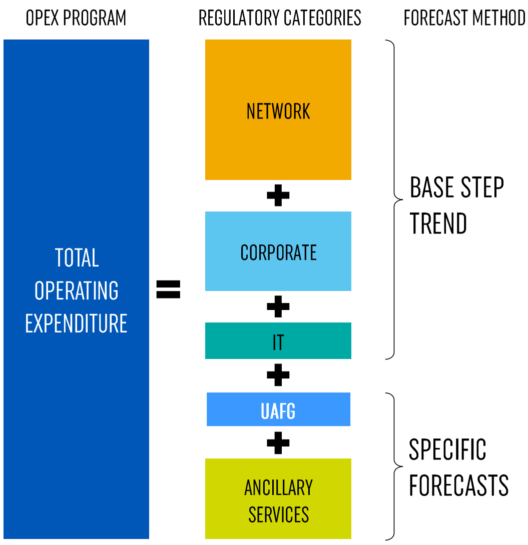
Our opex categories are outlined in Figure 11.1, and consist of expenditure relating to the categories of Network, Corporate, IT, UAFG, and Ancillary Services.

We have applied the base-step-trend (**BST**) approach to forecasting opex for the network, corporate, and IT categories. Regulators commonly apply the BST method. Section 11.5 provides further details of this method.

We have included two 'specific forecasts' in our submission, for opex relating to UAFG and our forecast of proposed retailer services (Ancillary Services) in AA5.

This chapter outlines our opex forecasts, our forecasting approach, and the primary drivers of opex over 2020-24.

**Figure 11.1:** Opex categories




## 11.2 Stakeholder engagement

From our VoC workshops, we found that customers who had interacted with ATCO, generally had positive experiences. Participants believed that we delivered a good service at a fair price. This view has also been supported by the feedback and satisfaction scores from Customer Service Benchmarking Australia, and the lower number of complaints received by ATCO from 2016 to 2017 compared to other comparable operators.

### 11.2.1 Customer feedback

Our ongoing engagement following the release of the Draft Plan provided timely and relevant feedback. There was support for our method of utilising the BST approach to forecasting network, corporate and IT expenditure. Stakeholders supported our efforts to reduce UAFG and supported the specific forecast that is set to achieve a UAFG reduction. Table 11.1 provides a summary of the main feedback received as it relates to the *Draft Plan*. We have now incorporated this feedback into our 2020-24 Plan.

**Table 11.1:** AA5 opex - stakeholder feedback and our response

| DRAFT PLAN QUESTION | STAKEHOLDER FEEDBACK | OUR RESPONSE TO FEEDBACK |
|---|---|---|
| Do you believe our opex forecasts are reasonable? | Stakeholders generally observed that the opex forecasts seemed reasonable given ATCO is historically an efficient gas distribution business. | **No change.** Our approach to forecasting opex is consistent with that outlined in our Draft Plan. |
| Do you believe the base-step-trend method of forecasting opex is appropriate? | Stakeholders generally agreed with our proposed base-step-trend approach to forecasting opex.<br>Some stakeholders expressed doubts about the ability of ATCO to continue to outperform on an efficiency basis compared to its peers. | **Change.** Our proposed opex program is consistent with our objective of owning and operating a safe, reliable and affordable gas distribution network that delivers services that are in the long-term interest of gas consumers. We have removed one step change from our forecast compared to the Draft Plan. |
| Do you support the proposed step changes to our base opex in relation to improved safety and compliance? | Some stakeholders requested more detail on specific opex elements of major investment programs, such as the billing system upgrade. | **No change.** Where appropriate, we have provided further detail on the opex aspects of our investment programs in this 2020-24 Plan. |

## 11.3 Regulatory framework

Consistent with Rule 91 of the NGR, our opex forecast is required to reflect that required by a prudent distributor, acting efficiently and in accordance with good industry practice to achieve the lowest sustainable cost of providing Reference Services to customers. Any forecast or estimate must be arrived at on a reasonable basis and must represent the best forecast or estimate possible in the circumstances.

## 11.4 Overview

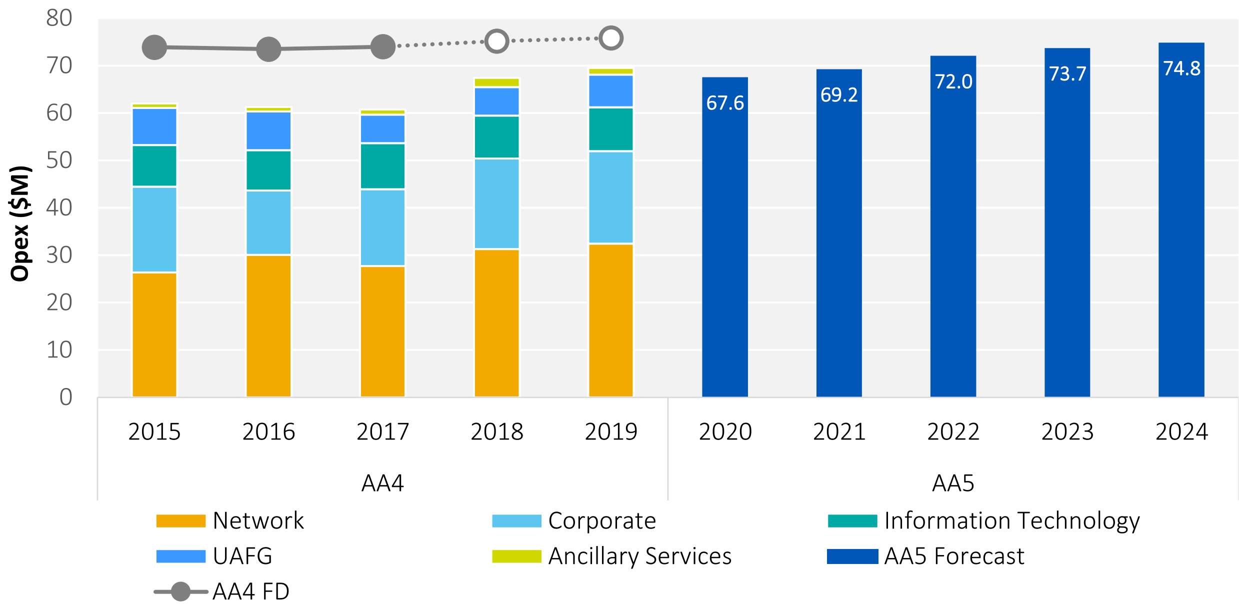
Our forecast opex in AA4 is expected to be $355 million, which is $51 million (or 13%) lower than the ERA's approved forecast amount. This reduction in expenditure is driven by our ongoing cost control over AA4. Our focus is to remain operationally efficient while focussing on customer needs and improving demand for natural gas.

Our forecast opex for AA5 is $357 million, building on an increase in operational activities in 2018 and 2019 as discussed in Section 11.6.2.1.

Figure 11.2 shows the comparison between AA4 and AA5 forecast opex. The AA5 forecast opex is $49 million (or 12%) lower than the ERA's AA4 Final Decision[22] (*'AA4 FD' in* Figure 11.2). The forecast opex incorporates an increase based on utilising the BST method while incorporating the efficiencies in the base year.

[22] AA4 was five and a half years.

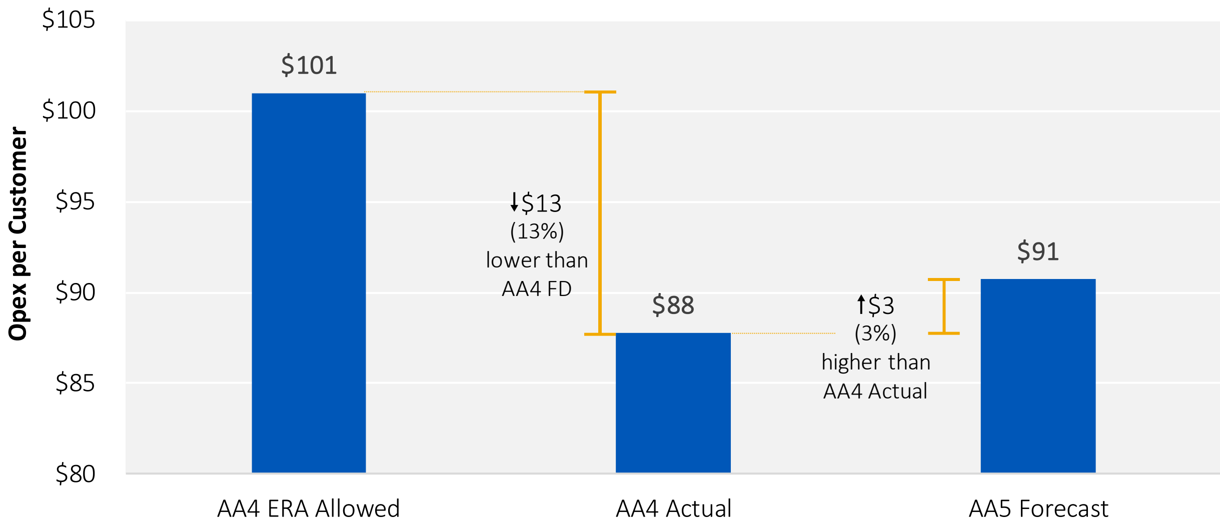
**Figure 11.2:** Opex per category – AA4 vs AA5 ($M real as at 31 December 2019)




In AA5, we expect our average opex per customer to be $91, compared to $101 per customer as approved by the ERA in AA4. Important comparisons regarding our Opex forecast *per customer* (see Figure 11.3):

- Our forecasted AA4 opex per customer is $13 (or 13%) lower on average compared to the ERA's AA4 FD.
- Our forecast opex is $3 per customer (or 3%) higher on average over AA5 compared to that incurred over AA4. The additional $3 per customer will enhance network safety, support programs that deliver long-term cost benefits, and increase customer engagement to provide further choice and customer value in energy solutions.
- Our forecast AA5 opex per customer is also $10 (or 10%) lower than the opex allowances approved in the ERA's AA4 FD.

**Figure 11.3:** Opex per customer comparison on average (5-yearly) ($M real as at 31 December 2019)




Our AA5 opex forecast is detailed in Table 11.2:

**Table 11.2:** AA5 opex summary ($M real as at 31 December 2019)

| OPEX CATEGORY | 2020 | 2021 | 2022 | 2023 | 2024 | TOTAL |
|---|---|---|---|---|---|---|
| **Network, Corporate and IT** | 58.4 | 60.1 | 63.1 | 64.8 | 66.0 | **312.4** |
| **UAFG** | 6.3 | 6.2 | 6.1 | 5.9 | 5.8 | **30.3** |
| **Ancillary** | 2.8 | 2.9 | 2.9 | 3.0 | 3.0 | **14.6** |
| **TOTAL** | **67.6** | **69.2** | **72.0** | **73.7** | **74.8** | **357.4** |

## 11.5 Forecast method

Our AA5 opex forecasting used two methods:

1. The base-step-trend method (BST).
2. Specific forecasts using volume-based activities multiplied by a unit rate to calculate total annual expenditure.

We have developed these forecasts on a reasonable basis, based on the best available information. We agree with the view that efficiency and prudence are complementary in that prudent expenditure reflects the best course of action given the alternatives, whereas efficient expenditure delivers the lowest cost to customers over the long-term[23].

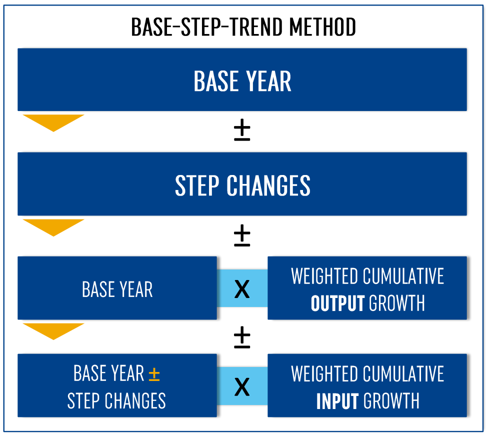
### 11.5.1 Base-step-trend method

Forecasting opex using the BST (or 'revealed cost') method has advantages over typical bottom-up forecasting approaches in that it takes the efficient costs incurred in the base year and uses the assumption that opex is mostly recurrent.[24] BST forecasting starts by establishing our base opex, then adjusting for:

- any expenditure not reflective of the recurrent cost base;
- categories of opex affected by discrete step changes; and
- changes in output and cost input trends over the period.

The BST method of forecasting opex has been commonly accepted as the method to forecast efficient opex. A summary of how we forecast using the BST method is provided in Figure 11.4 and Figure 11.5.

**Figure 11.4:** BST calculation




[23] AER (2013) "Expenditure Forecast Assessment Guideline – Distribution – November 2013", pg. 6. Available at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/expenditure-forecast-assessment-guideline-2013

[24] AER (2013) "Expenditure Forecast Assessment Guideline – Distribution – November 2013", pg. 9. Available at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/expenditure-forecast-assessment-guideline-2013

**Figure 11.5:** BST Method

| 1 Establish the efficient base year | 2 Adjust for step changes in recurrent opex | 3 Adjust for non-recurrent opex | 4 Trend to account for network growth | 5 Escalate for labour costs |
|---|---|---|---|---|
| We have used the estimated 2019 base year, calculated from our 2017 year actuals, as a representation for the cost base within the base-step-trend. | We have forecast and adjusted the recurrent base year opex for increases or decreases in costs arising from new or amended obligations and activities over the AA5 period. | We have forecast and adjusted the opex for changes in costs arising from new or amended obligations and activities expected to occur as discrete activities over the AA5 period. | We have forecast the growth drivers of opex and included changes in costs associated with servicing a growing network and customer base over the AA5 period. | We have forecast changes in the cost of labour over the AA5 period and escalated total opex based on widely used assumptions. |

### 11.5.2 Specific forecasts

We applied specific forecasts to UAFG and Ancillary Services. We chose to complete specific forecasts for these opex categories as the forecast expenditure profile does not specifically relate to the BST method.

For example, we forecast that the *percentage of UAFG* to *customer gas usage* should reduce over AA5, which is disproportionate to the method of growth as per the BST method. We explore these forecasts further in Sections 11.6.6 and 11.6.7.

## 11.6 Forecast opex

This section provides an explanation of each component of our opex forecast and how we arrived at our final opex forecast. Table 11.3, Figure 11.6 and Figure 11.7 provide a summary of the AA5 forecast total opex.

**Table 11.3:** Forecast AA5 opex ($M real as at 31 December 2019)

| FORECAST OPEX | 2020 | 2021 | 2022 | 2023 | 2024 | TOTAL |
|---|---|---|---|---|---|---|
| Base year | 54.8 | 54.8 | 54.8 | 54.8 | 54.8 | **273.8** |
| Recurrent Step Changes | 1.4 | 1.5 | 1.8 | 1.9 | 1.9 | **8.5** |
| Non-recurrent Step Changes | 0.9 | 0.9 | 2.1 | 2.3 | 1.9 | **8.1** |
| Output Growth | 0.9 | 1.7 | 2.6 | 3.5 | 4.4 | **13.0** |
| Input Cost | 0.6 | 1.2 | 1.8 | 2.4 | 3.0 | **9.0** |
| Productivity Growth | - | - | - | - | - | **-** |
| UAFG | 6.3 | 6.2 | 6.1 | 5.9 | 5.8 | **30.3** |
| Ancillary Services | 2.8 | 2.9 | 2.9 | 3.0 | 3.0 | **14.6** |
| **TOTAL** | **67.6** | **69.2** | **72.0** | **73.7** | **74.8** | **357.4** |

**Figure 11.6:** Forecast AA5 opex ($M real as at 31 December 2019)

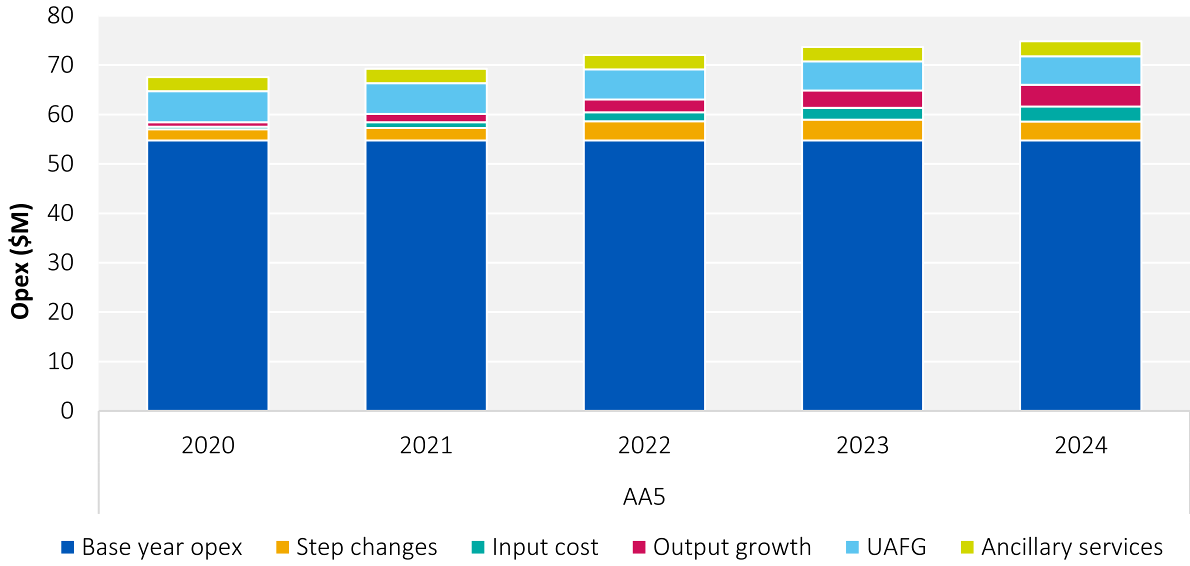
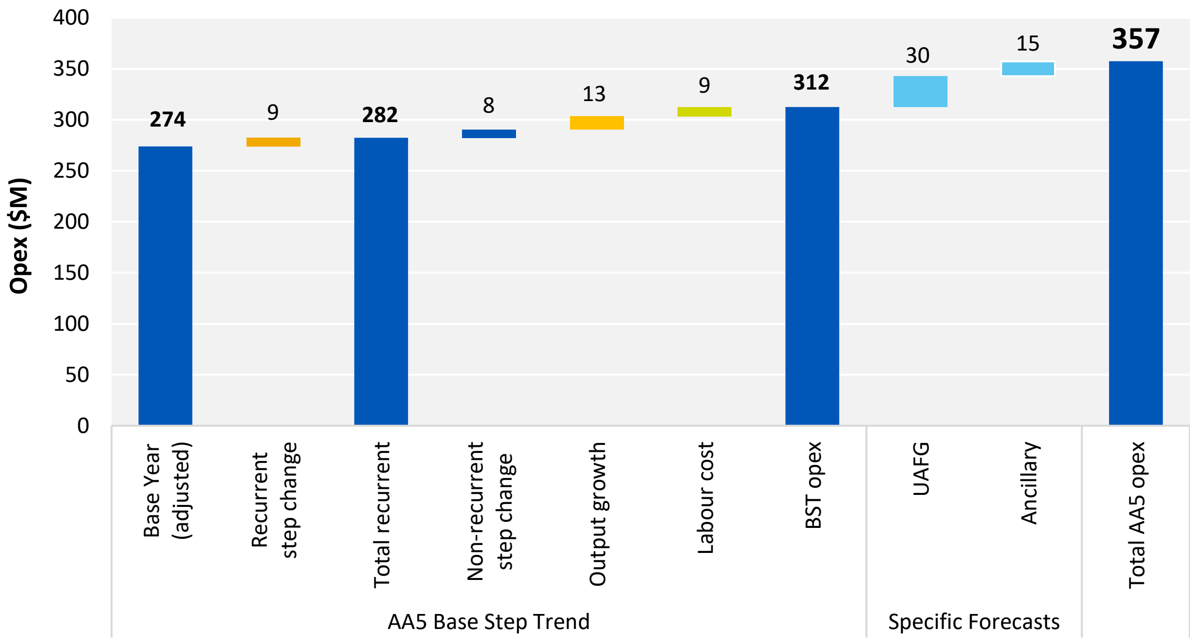



**Figure 11.7:** Forecast AA5 opex (using the BST and category specific breakdown) ($M real as at 31 December 2019)



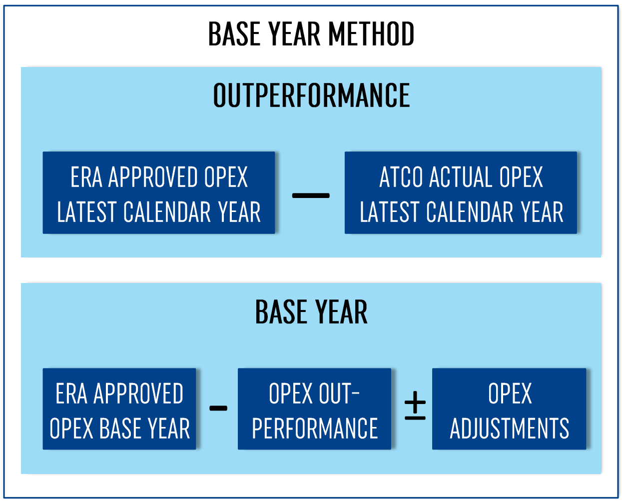

### 11.6.1 Establish the efficient base year

We have determined the best forecast of our 2019 base year cost using the estimated final year method. Under this method, we have used our actual opex from the most recent complete calendar year (2017) as representative of our opex for AA5. We have established our base AA5 opex by comparing the level of opex outperformance in 2017 (compared to our AA4 forecast) and then applying that level of outperformance to the AA4 2019 opex allowable forecast. This approach ensures that the base opex includes the expected movement in opex over the remainder of AA4. The use of a base level of opex (based on actuals), reflects that opex is recurrent in nature. However, some adjustment is required to the base year costs to ensure *only recurrent costs* are reflected in the base year forecast.

Adjustments relate to our base opex (2017), and under the method adopted, forecast non-recurring costs in the final base year (2019). Two adjustments were made to the base year opex including: (1) updating for actual employee incentive payments in 2017 (versus the provisional amount in the regulatory financial statements for 2017); and (2) removed AA5 preparation costs in the final year of AA4.

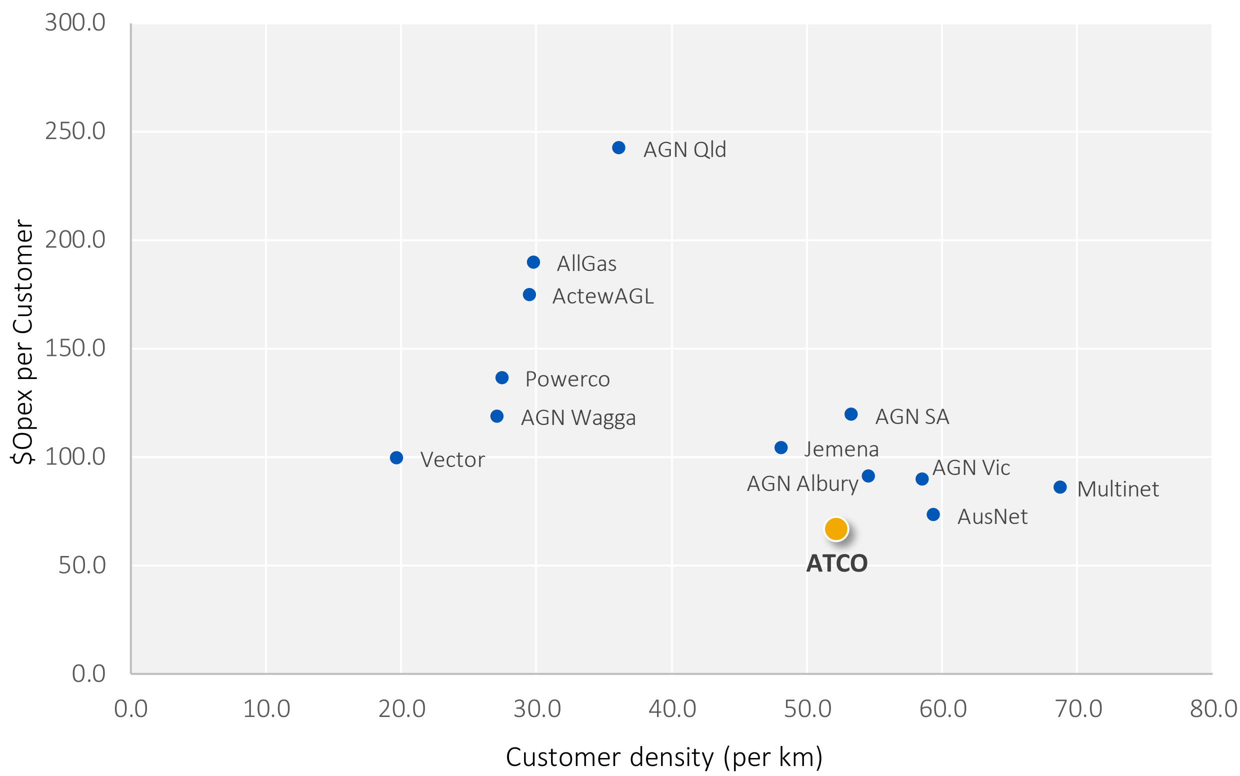
Our outperformance reflected in the base year calculation is one way to forecast the efficiencies derived over AA4 (see Figure 11.8). We believe this achieves the best possible forecast at this time. Using the most recent calendar year reflects the most recent cost estimates to project forward expenditure to limit deficiencies in past expenditure decisions.

**Figure 11.8:** Opex base year calculation method




To understand if the base year is efficient, we sought expert advice on how our opex costs benchmark against our peers in other states. Economic Insights performed analysis[25] that showed we are the best performer in Australia and New Zealand for delivering opex per customer, as shown in Figure 11.9. We believe that this evidence provides assurance that our base year reflects efficient costs and supports the BST method.

**Figure 11.9:** Opex per customer[26] relative to customer density ($2010, average 2013-2017)

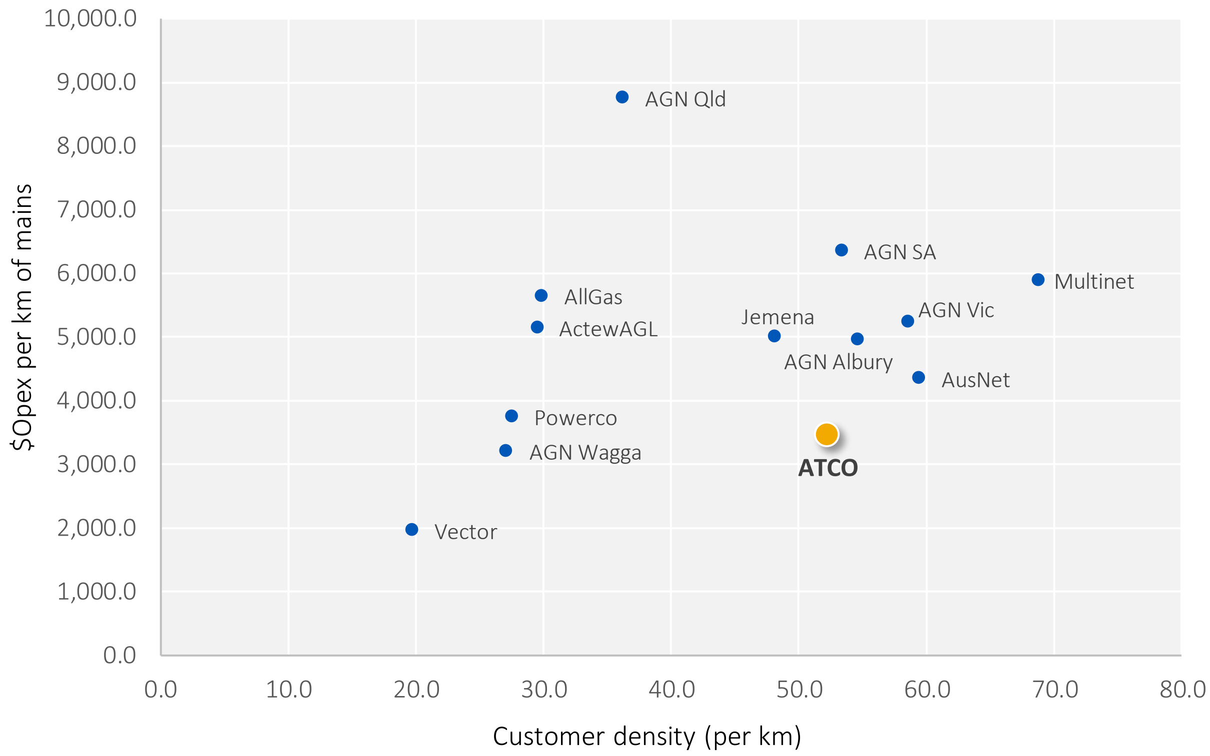



25 Cunningham, M. (2018) "Benchmarking Operating and Capital Costs of ATCO Gas' Western Australian Network Using Partial Productivity Indicators", Economic Insights. Report prepared for ATCO Gas Australia. See Attachment 5.1.

26 'Opex per customer' and 'Opex per km' calculations do not include the cost of UAFG

Our low costs are also reflected in our opex cost per km (refer Figure 11.10) being one of the lowest against our peers, which also highlights the efficiency in our network considering our predominant coastal (north–south) profile.

**Figure 11.10:** Opex per km of mains[27] relative to customer density (customers per km) ($2010, average 2013-2017)




## 11.6.2 Non-base year opex

The next step in the BST approach is to review future opex obligations that fall outside the base year. These opex costs are for additional recurring costs that *were not incurred within the base year (i.e. beginning after 2017)*, for example, due to a capital project shifting from construction to operation or a change in legislation. Costs can also be one-off expenditure with an ongoing frequency that falls outside the base year (e.g. every three years). We have also identified several other obligations that are driving changes to our costs that are considered immaterial and have not been included in the forecast.

The justification for each of these step changes is summarised below with further information provided in relevant business cases and project briefs as referenced against each description.

### *11.6.2.1 Adjusting for step changes in recurrent opex*

Activities during AA5 that are not reflected in our base year are known as 'step changes'. Step changes include the additional costs of associated safety, compliance, and regulatory activities that are typically driven by a change in obligation. The step changes we have identified for AA5 are detailed in Table 11.4.

27 'Opex per customer' and 'Opex per km' calculations do not include the cost of UAFG

**Table 11.4:** Adjustments for step changes in recurrent opex ($M real as at 31 December 2019)

| RECURRENT STEP CHANGE EXPENDITURE | AA5 TOTAL |
|---|---|
| Additional leak survey and repair | 5.0 |
| New interconnections | 1.2 |
| Supervisory Control and Enhanced Data Acquisition | 2.3 |
| **TOTAL** | **8.5** |

- **Additional leak survey and repair** (including mains in private property)

  We are further expanding the scope of planned leak survey activities. This scope will include leak surveying at the location of the meter, as the below ground assets are potential leak points due to conditions such as age, installation type and environment. The expansion commenced in 2018 and will further expand in 2019 and into AA5 with the inclusion of meter positions in high-density community use locations[28], city centre, commercial, and residential areas.

  The addition of these locations was identified as part of the formal safety assessment process as required under the Gas Standards[29] . The main Australian Standard[30] for gas distribution prescribes the requirement to complete a formal safety assessment to understand the risk and associated controls to manage leaks. This assessment proposed further action to satisfy our Safety Case[31] and Australian Standard requirements. The formal safety assessment was informed by benchmarking best practice across Australia, historical leak data, and additional leak survey trial information. Refer to Attachment 11.4: '*Project Brief Additional Leak Survey and Repair*' for more information about this project.

- **PGP interconnections**

  We will increase the security of supply within our network by adding offtake facilities (gate stations) to the PGP. These facilities will maintain the supply of gas to the metropolitan network in the event of an emergency supply shortage from the Dampier to Bunbury Natural Gas Pipeline (as described further in Section 12.7.5).

  The proposed new gate stations require regular maintenance to ensure the facilities are operating according to their design specification. We will support the ongoing operation and maintenance of the new gate stations within Rockingham (2020), South Metro (2021), and North Metro (2022).

- **Supervisory Control and Enhanced Data Acquisition**

  We propose to further optimise the network through remote control of capacity management and enhanced data acquisition on additional assets (as outlined in Section 12.7.4). The additional assets installed as part of this program require both capex and opex to ensure they are maintained and operated to their intended design specifications.

  We propose to improve network efficiency through supervisory control and data acquisition (**SCADA**); a control system architecture that improves our ability to:

  - Monitor, gather, process, and control real-time network data from local or remote locations.

[28] High-density community use locations include areas where buildings of four or more storeys are prevalent, major shopping centres, schools, hospitals, aged care facilities, and major sporting and cultural facilities. Public infrastructure (e.g. roads and railways, trafficable tunnels) in direct proximity of the high-density community use area is also deemed to be part of the high-density community use area.

[29] As per Gas Standards (Gas Supply and System Safety) Regulations (GSSR) 2000 (Part 4 — Distribution system safety)

[30] AS/NZS 4645.1 Gas distribution networks- Network management

[31] ATCO Gas Australia, *Gas Distribution System Safety Case*, December 2017

- Introduce remote control on isolation valves, introduce remote pressure control to improve network risk management, and lower costs through reducing future UAFG and capex costs.
- Improve gas quality management systems, thus increasing network safety and reducing UAFG.
- Record valuable network data for analysis, including optimising future growth and reinforcement of the network.

The expenditure ensures the coverage of operational and information technology costs (one-off and ongoing), licencing, and ongoing support from third-party vendors.

#### *11.6.2.2 Adjusting for step changes in non-recurrent opex*

Several non-recurrent costs will occur during AA5 that are not reflected in our base year. Table 11.5 summarises the components of the non-recurrent step changes and the years they apply to the forecast.

**Table 11.5:** Adjustments for non-recurrent step changes ($M real as at 31 December 2019)

| NON-RECURRENT STEP CHANGE EXPENDITURE | YEAR | AA5 TOTAL |
|---|---|---|
| Hazardous areas review & remediation | 2020, 2021 & 2022 | 0.8 |
| Pipeline inline inspections | 2020 to 2024 | 3.0 |
| Mains reclassification | 2020, 2021 & 2022 | 0.6 |
| Asset & Business Management System Review | 2022 | 0.7 |
| Access Arrangement Six regulatory preparation | 2023 & 2024 | 2.9 |
| **TOTAL** | | **8.1** |

The justification for each of the non-recurrent costs is detailed below:

- **Hazardous areas review and remediation**

  An external *Gas Distribution System Safety Case* audit[32] was conducted in 2017 as part of our requirements of maintaining our safety and operating plan in conjunction with the Australian Standard[33]. The audit proposed the following relating to our telemetry and electronic equipment located within the vicinity of our gas containing assets:

  1. *Develop and maintain a register for all 'Ex' rated electrical equipment used in hazardous areas at pressure reduction stations, which should contain as a minimum, information such as 'hazardous zone', 'protection type', 'temperature class', 'gas group' and details of 'Ex' certification.*
  2. *Investigate and document the requirement to undertake regular Electrical Equipment in Hazardous Area (EEHA) inspections for all 'Ex' rated electrical equipment in order to maintain their integrity for use in hazardous areas, in accordance with the requirements of 'AS/NZS 2381.1:2005 Electrical equipment for explosive gas atmospheres - Selection, installation and maintenance – General requirements'. As part of this action, ensure and document that a competent EEHA electrical inspector is used for such inspections.*

  The audit also stated:

32 Environmental Risk Solutions, *ATCO Gas Australia Gas Distribution System Safety Case audit*, revision 1, 9 January 2017

33 AS/NZS 4645.1:2008 Gas distribution networks- Network management

> *Certification of hazardous area rated electrical equipment is mandatory, and inspections of such equipment are required to be undertaken regularly. This is to maintain their integrity, and more importantly, to ensure that an ignition source is not inadvertently present in the event of exposure to flammable gas. Inspections are required for all rated electrical equipment in accordance with the requirements of the Australian Standards*[34]*.*

We commenced work in 2018 to ensure higher priority non-compliant equipment was rectified within the required timelines. We will complete this project in 2022, with the opex including re-design costs, consultancy fees, and remediation of existing facilities. Refer to Attachment 11.3: '*Project Brief Hazardous Areas Review and Remediation*' for more information about this project.

- **Pipeline inline inspections**

  High-pressure steel pipelines require internal inline inspections as prescribed in the Australian Standards[35] undertaken in line with the Gas Standards[36]. Our formal safety assessment highlighted internal inspections as an important risk control, forming part of our pipeline integrity management plans.

  This activity includes modifications to pipelines to enable internal inspection via a pipeline inspection gauge. Pipeline inspection using these inline gauges allows detection of internal or external anomalies or pipe wall material loss. Major gas pipelines are inspected at a determined frequency (typically every ten years) as per the standard industry practice.

  The pigging of major pipelines continues in AA5 after successful project completions in AA4. However, no pipeline inspections were completed in the 2017 base year and are therefore included as a non-recurrent step change. We will be undertaking pipeline inline inspections in 2020, 2021, 2022, 2023 and 2024. This non-recurrent expenditure is linked directly to the capex related to the pipeline inspections as detailed in Section 12.7.5.

- **Mains reclassification**

  The new gas distribution Australian Standard[37] defines a main (gas pipe) as '*a pipe installed to convey gas to individual services or other distribution facilities*'. The standard definition for services has been updated based on volume. As a result, we have re-defined the criteria for mains and services and identified approximately 6,000 locations where mains require updating to be available within the gas network information system.

  We carried out a formal safety assessment to ensure the maintenance of these assets was covered by our current safety and operating plan as required by Australian Standards. The formal safety assessment requires us to reassess existing assets to improve our asset management responsibility for these assets. In addition, we will comply with DBYD requirements and our internal controls, including updating our databases to include mains that enter large complexes and have multiple service offtakes.

  This project commenced in AA4 on a prioritised basis and will be completed in 2022. We will continue the project in 2018 and 2019 to ensure we comply with the new Standard definitions within a reasonable timeframe. Refer to Attachment 11.5: '*Project Brief Mains Reclassification*' for more information about this project.

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34 AS/NZS 2381.1:2005 Electrical equipment for explosive gas atmospheres- Selection, installation and maintenance – General requirements.

35 AS/NZS 2885.3:2001 Pipelines- Gas and liquid petroleum- Operation and maintenance Section 3.4 Threat Mitigation & AS/NZS 2885.3:2012 Pipelines- Gas and liquid petroleum- Operation and maintenance Section, Section 6.4.2 Corrosion Mitigation Strategy

36 As per Gas Standards (Gas Supply and System Safety) Regulations (GSSR) 2000 (Part 4 — Distribution system safety)

37 Gas distribution networks Part 1: Network management

- **Asset and business management system review**

  Our enterprise resource planning (**ERP**) system (SAP) is used for the management of the GDS assets throughout their lifecycle. The ERP enables us to monitor, maintain and replace assets prudently and efficiently. It supports the identification and justification of necessary investment and understanding of an asset's risk profile and forecast expenditure.

  It is a condition of our Gas Distribution License and the Energy Coordination Act 1994 that we have in place an asset management system, which is a critical tool in the safe, reliable, and efficient operation of a gas distribution network.

  Based on our ERP's product lifecycle, we will be required to implement a major upgrade of the application in AA6. In preparation for an upgrade of this complexity and magnitude, the planning and scoping phase of the project will be completed in 2022. This timing enables us to make an informed decision on the transition from the current ERP system to the selected solution and include the associated prudent and efficient costs in AA6. Refer to Attachment 12.13: '*IT Asset Strategy*' for more information about this project.

- **Access Arrangement Six (AA6) preparation**

  We have had an access arrangement in place since 2000 and have previously agreed three revisions (AA2, AA3 and AA4) with the ERA. The next access arrangement, AA5, covers the period 1 January 2020 to 31 December 2024. A subsequent access arrangement revision is required for the period commencing 1 January 2025.

  AA6 regulatory preparation in 2023 and 2024 will require additional AA5 expenditure to ensure compliance with the NGR. Expenditure has been based on the forecast costs for the AA5 preparation including consultancy fees, project management fees and additional resources supplied to ensure we present the best possible submission with costs that remain prudent and efficient for the duration.

#### *11.6.2.3 Additional costs identified but no allowance made for in AA5*

We have identified several other obligations driving changes to our costs. At this time these changes are not considered material and have not been included as step changes in the forecast. For further examples, refer to Section 11.6.5.

### 11.6.3 Trend to account for forecast output growth

We incur additional expenditure as the number of customers connected to our network increases and as the size of our network increases. Examples of this expenditure include meter reading costs, leak survey, network maintenance, and incremental facility costs to maintain network pressures within the GDS. Our base year opex is escalated by forecast growth in customer numbers and the physical size of our distribution network (measured in km of mains).

There are several ways that growth escalation can be determined, which are based on the growth escalation factors used in gas distribution businesses. Recent submissions to the AER have used customers and network size[38], customers and throughput[39], or customer growth only[40]. ACIL Allen[41] conducted analysis for Australian Gas Networks (AGN), showing that customers and network size drive operating costs in gas distribution networks[42]. The ACIL Allen analysis concluded that *energy throughput is not a key driver of increasing operating expenses,* and this was further supported by Economic Insights findings[43] for Multinet Gas that *gas throughput is not a statistically significant determinant of real opex*.

Our approach is consistent with the method approved by the AER in recent gas distributor submissions: adopting a weighted average of 1.6% per annum growth between customers and network size using a weighting of 45% and 55% respectively[44,45]. Our growth forecasts (shown in Table 11.6) result in a total increase of $13.0 million in opex over AA5 (shown in Table 11.7).

**Table 11.6:** Forecast output growth factors for AA5 ($M real as at 31 December 2019)

| FORECAST GROWTH FACTORS | WEIGHTING | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|
| Net growth in the number of customers | 45% | 12,155 | 12,351 | 12,617 | 12,909 | 13,171 |
| Net growth in the length of the network (km) | 55% | 216 | 208 | 218 | 217 | 249 |
| Weighted annual output growth rate | - | 1.57% | 1.52% | 1.55% | 1.54% | 1.65% |

**Table 11.7:** Forecast output growth for AA5 ($M real as at 31 December 2019)

| FORECAST OUTPUT GROWTH | 2020 | 2021 | 2022 | 2023 | 2024 | TOTAL |
|---|---|---|---|---|---|---|
| **Forecast output growth** | **0.86** | **1.70** | **2.58** | **3.47** | **4.43** | **13.04** |

### 11.6.4 Trend to account for forecast input growth

Forecast input growth (or cost) typically is driven by price increases in labour and non-labour (e.g. materials), see Table 11.8 and Table 11.9. Our forecast growth in costs results in an additional $9.0 million of opex in AA5. Our approach to escalating costs is based on:

- An opex resource mix of 62% labour and 38% non-labour costs based on benchmark weights developed by the Pacific Economics Group.[46]

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38 AusNet Services (2017) "AusNet Services- Access Arrangement 2018-2022 Proposal". Available at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ausnet-services-access-arrangement-2018-22/proposal

39 Multinet Gas (2017) "Multinet Gas- Access Arrangement 2018-22 Proposal". Available at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/multinet-gas-access-arrangement-2018-22/proposal

40 Australian Gas Networks (2017) "Australian Gas Networks (Victoria and Albury)- Access Arrangement 2018-22 Proposal". Available at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/australian-gas-networks-victoria-and-albury-access-arrangement-2018-22/proposal

41 ACIL Allen, Opex Partial Productivity Analysis, 20 December 2016, pages 27-28. Completed for Australian Gas Networks (AGN) Limited. Available at: https://www.aer.gov.au/system/files/AGN%20-%20Attachment%207.3%20-%20ACIL%20Allen%20-%20Opex%20Partial%20Productivity%20Analysis%20-%2020161220%20-%20Public%5B1%5D.pdf

42 ACIL Allen, Opex Partial Productivity Analysis, 20 December 2016, pages 27-28. Completed for Australian Gas Networks (AGN) Limited. Available at: https://www.aer.gov.au/system/files/AGN%20-%20Attachment%207.3%20-%20ACIL%20Allen%20-%20Opex%20Partial%20Productivity%20Analysis%20-%2020161220%20-%20Public%5B1%5D.pdf

43 Economic Insights (2016) "Gas Distribution Businesses Opex Cost Function", Report prepared for Multinet Gas, 22 August 2016

44 Economic Insights (2016) "Gas Distribution Businesses Opex Cost Function", Report prepared for Multinet Gas, 22 August 2016

45 AER- Draft decision- Multinet Gas access arrangement 2018-22- Attachment 7- Operating expenditure, 6 July 2016

46 Pacific Economics Group, TFP Research for Victoria's Power Distribution Industry, December 2004. Available at: http://www.esc.vic.gov.au/wp-content/uploads/archives/9175/3267_PEG_TFP_Report.pdf

- Labour cost escalation over AA5 is based on the Synergies forecast annual rate of growth in the wage price index for Western Australian electricity, gas, water, and waste water services. The AA5 average annual growth in labour escalation is 1.64% with further information provided in Attachment 12.9: *'Synergies Economic Consulting – Consumer price index and wage price index forecasts'*.
- No real cost escalation for non-labour costs. We have forecast that materials do not incur any additional price rises over and above inflation.

**Table 11.8:** Forecast input growth factors for AA5 ($M real as at 31 December 2019)

| INPUT GROWTH FACTOR | WEIGHTING | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|
| Labour | 62% | 1.64% | 1.64% | 1.64% | 1.62% | 1.66% |
| Materials | 38% | - | - | - | - | - |
| **Weighted annual input growth rate** | | **1.02%** | **1.02%** | **1.02%** | **1.00%** | **1.03%** |

**Table 11.9:** Forecast input growth for AA5 ($M real as at 31 December 2019)

| FORECAST INPUT GROWTH | 2020 | 2021 | 2022 | 2023 | 2024 | TOTAL |
|---|---|---|---|---|---|---|
| **Forecast input growth** | **0.58** | **1.17** | **1.81** | **2.43** | **3.04** | **9.03** |

### 11.6.5 Productivity growth

We have not applied a productivity adjustment on the basis that our benchmark performance is already considered efficient compared to our peers (*see Figure 1.1 and Section 11.6.1*). We do not believe that a productivity adjustment is in the long-term interests of customers as it would likely yield adverse implications for our ability to provide a safe and reliable natural gas service. We consider this is the best estimate available with our current information and benchmarked performance.

In addition, we highlight that in proposing a zero rate of change productivity adjustment, we are absorbing some cost increases as outlined in Section 11.6.2.3.

We will absorb $2.6 million in identified step changes over AA5 that fall outside the base year. Table 11.10 provides a summary of the individual components that make up this expenditure with summary descriptions given below.

**Table 11.10:** Additional step changes identified but not allowed for in the AA5 opex forecast ($M real as at 31 December 2019)

| STEP CHANGES NOT ALLOWED FOR IN AA5 FORECAST OPEX | AA5 TOTAL |
|---|---|
| Asset sampling & testing | 0.13 |
| Third-party damage prevention and pipeline safety | 1.84 |
| Additional vegetation clearing for Bunbury & Busselton | 0.08 |
| Condition assessment and data gathering in CBD | 0.02 |
| Overpressure shut-off devices maintenance | 0.57 |
| **Total** | **2.63** |

- **Asset sampling & testing**

  This project is linked to our Pipeline, Mains and Service ALS (please refer to Attachment 12.4: *'Pipeline, Mains and Services'*) and aligned with the PVC mains replacement project (refer Section 12.7.1). This requirement is not dependent on the outcome of that project; however, it is linked and will inform further asset replacement decisions for current and future forecasting.

- **Third-party damage prevention**

  We have conducted a formal safety assessment in accordance with Australian Standards[47] and we are further expanding the scope of third-party damage prevention. The formal safety assessment incorporated upcoming changes to Australian Standards[48] in relation to mitigation of supply loss risks. To meet the new requirements, further resourcing is required to continue our strong message of safety around our assets and ensure continued network reliability as valued by customers. We will continue to invest resources in prevention mechanisms such as DBYD, external locators, and increased network monitoring. With a larger network footprint however, there is an increased risk of third-party damage that requires mitigation. The proposed expenditure relates to mitigating our security of supply risks; including additional pipeline patrols, increasing numbers, and training of external high-pressure locators, and further collaboration with our industry partners including DBYD.

- **Additional vegetation clearing for Bunbury & Busselton**

  Due to environmental considerations, we will be conducting vegetation clearing and further studies in the Bunbury & Busselton region due to the increase in pipelines and changes in the Department of Environment considerations.

- **Condition assessment and data gathering in the Perth CBD**

  The lack of information about the condition of the gas network in the Perth CBD has been highlighted as a risk as part of our network Formal Safety Assessment. We are gathering further information in this project to remediate the defects and non-compliant installations in these locations.

- **Overpressure shut-off devices maintenance**

  Overpressure shut-off (**OPSO**) devices require approximately 50,000 additional minutes of activity per year. Unit rates for this activity have increased by approximately $56 per unit of maintenance. Further information about unit rate activities is given in Attachment 12.49: *'Unit Rates Forecast'*.

### 11.6.6 UAFG

Our UAFG forecast contributes $30.3 million to AA5 opex. Our UAFG costs have reduced over AA4 due to targeted capital projects such as mains replacement and further enhancements in finding and eliminating leaks. Over AA4 we have been proactive in improving our gas measurements to achieve higher accuracy of metering at our interconnection points (operated by third parties) and higher accuracy of metering at our customers' meters. In late 2016 an error in third-party transmission gas measurement occurred causing an error in the measured UAFG amount. This error over-inflated our UAFG reductions; however, forecast UAFG levels provide an estimate considering this error and measurable improvements in AA4.

UAFG is the difference between the measurement of the quantity of gas *delivered* ***into*** the gas distribution system in a given period and the measurement of the quantity of gas *delivered* ***from*** the gas distribution

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47 AS/NZS 4645.1:2008 Gas distribution networks- Network management & AS/NZS 2885.1:2007 Pipelines- Gas and liquid petroleum-Design and construction

48 Our current Gas Standards (Gas Supply and System Safety) Regulations (GSSR) 2000 prescribe the Australian Standards above. Standards Australia has released updates of these: AS/NZS 4645.1:2018 Gas distribution networks- Network management & AS/NZS 2885.1:2012 Pipelines- Gas and liquid petroleum-Design and construction

system during that period. We incur costs as a result of purchasing gas to replace calculated UAFG and these costs are then recovered from customers through tariffs.

UAFG makes up a material proportion of opex in each access arrangement; therefore, it is in the long-term interests of customers and consistent with good industry practice that we reduce the UAFG rate to as low as reasonably practicable. Our UAFG rates are currently lower than the three Victorian gas distribution networks.[49]

We have achieved further reductions in UAFG by:

- Additional accuracy verification tests at third-party interconnections (gate stations) to validate the least metering error possible.
- Replacement of all unprotected metallic mains (by the end of AA4) (excluding crossings).
- Maintaining a strong focus on mains replacement in areas experiencing above-average leakage rates.
- Ensuring all values in the billing system are accurate and using the latest data.
- Increasing leak survey and leak elimination activities (refer Section 11.6.2.1) while utilising better techniques and technology to ensure better sensitivity and precision.

We have separately forecast the costs of UAFG in AA5 through the calculation of:

- Forecast UAFG volumes (using historical UAFG rates as a percentage of total gas throughput, taking into account UAFG reductions (e.g. mains replacement))
- *Multiplied by* the forecast unit gas price for UAFG.

The forecast unit gas price for UAFG has been estimated based on the most recent publicly available information and predictions. The price per unit of UAFG (per unit of energy, typically gigajoules (GJ)) is made up of:

- Wholesale cost (i.e. the wholesale market price).
- Transmission tariff (i.e. the cost of transportation to the ATCO GDS).
- Retailer charge (i.e. the retail margin to purchase the gas).

The forecast unit rate for AA5 will be subject to change via a tender process to begin in late 2018. This tender process will inform us and the ERA of the actual price of UAFG per GJ that will be used as the basis for our response to the draft decision. We think this is the most efficient process and will deliver the lowest total UAFG cost in AA5. For further information see Attachment 11.2: *'Unaccounted for Gas Forecast and Pricing Strategy'*.

### 11.6.7 Ancillary reference services

Our ancillary reference service contributes $14.6 million to AA5 opex.

Ancillary service volumes have been forecasted based on historical growth and current retailer demands. Ancillary service costs have been forecasted based on current costs of providing these services. With the additional retailers entering the WA gas market and competing for customers, we have realised that more customers are choosing to switch retailers. This increased switching has caused an unprecedented increase in special meter reading, and therefore forecasted Ancillary Services now include a forecast for special meter readings. The specific forecast includes the following Ancillary Services:

- Applying a meter lock

[49] Sincere, Review of Unaccounted for Gas Benchmarks – Calculation Prepared for Essential Services Commission, December 2017. https://www.esc.vic.gov.au/wp-content/uploads/2017/12/review-of-unaccounted-for-gas-benchmarks-calculation-prepared-for-essential-services-commission-by-zincara-pty-ltd-20171218.pdf

- Removing a meter lock
- Deregistering a delivery point
- Disconnecting a delivery point
- Reconnecting a delivery point
- Special meter reading

For further information on these individual reference services, see Chapter 8.

## 11.7 Opex categories

The purpose of this section is to provide further information on our opex forecasting for AA5. The BST method is a top-down forecasting method of opex over AA5. We have cross-checked our top-down forecast against a bottom-up forecast of opex. We found that our bottom-up forecast of opex was generally higher than the top-down opex forecast using the BST method. Despite this, we intend to adopt an AA5 opex forecast from the BST method, as we consider that this is the best forecast available with our current information and benchmarked performance.

The bottom-up forecast of opex provides additional cost category breakdown for AA5 categorised into Network, Corporate, IT, UAFG and Ancillary Services and is shown in Table 11.11.

**Table 11.11:** AA5 forecast opex using the bottom-up method with the new cost category breakdown ($M real as at 31 December 2019)

| OPEX CATEGORY | 2020 | 2021 | 2022 | 2023 | 2024 | TOTAL |
|---|---|---|---|---|---|---|
| Network Opex | 36.1 | 36.8 | 38.3 | 38.4 | 39.0 | **188.7** |
| Corporate Opex | 17.5 | 17.5 | 17.7 | 19.4 | 19.4 | **91.4** |
| IT Opex | 7.4 | 7.3 | 8.8 | 7.8 | 7.8 | **39.2** |
| UAFG | 6.3 | 6.2 | 6.1 | 5.9 | 5.8 | **30.3** |
| Ancillary | 2.8 | 2.9 | 2.9 | 3.0 | 3.0 | **14.6** |
| **TOTAL – Bottom-up** | **70.2** | **70.8** | **73.8** | **74.4** | **75.0** | **364.2** |
| TOTAL – BST | 67.6 | 69.2 | 72.0 | 73.7 | 74.8 | 357.4 |
| *VARIANCE* | *2.6* | *1.6* | *1.8* | *0.7* | *0.2* | *6.8* |

In 2018, we have changed our approach for reporting IT expenditure; we now incorporate the relevant IT costs for Network and Corporate into those categories. This change in approach results in cost-centre managers being more accountable for their costs, which drives efficiency. The result is that the cost categories have changed from our historical actuals (Network and Corporate have increase but IT has decreased).

To assist with comparing our AA4 performance against this bottom-up forecast of opex, we have also provided the cost category breakdown based on our historical reporting method, which provides a comparison between AA4 and AA5 (see Table 5.5 and Table 11.12). UAFG and Ancillary Services remain the same as our forecasts in the above sections for AA5.

**Table 11.12:** AA5 forecast opex using the bottom-up method with historical cost category breakdown for comparison ($M real as at 31 December 2019)

| OPEX CATEGORY | 2020 | 2021 | 2022 | 2023 | 2024 | TOTAL |
|---|---|---|---|---|---|---|
| Network Opex | 34.4 | 35.1 | 36.6 | 36.6 | 37.2 | **179.9** |
| Corporate Opex | 17.1 | 17.2 | 17.3 | 19.0 | 19.0 | **89.5** |
| IT Opex | 9.5 | 9.5 | 11.0 | 9.9 | 10.0 | **49.9** |
| UAFG | 6.3 | 6.2 | 6.1 | 5.9 | 5.8 | **30.3** |
| Ancillary | 2.8 | 2.9 | 2.9 | 3.0 | 3.0 | **14.6** |
| **TOTAL** | **70.2** | **70.8** | **73.8** | **74.4** | **75.0** | **364.2** |

Our BST opex forecast meets the test in Rule 91 of the NGR, with our benchmark performance showing we are already operating more efficiently than our peers. The BST approach ensures efficiencies are captured and the adjustments proposed to the base year are robust and efficient, based on reasonable growth and cost assumptions backed by sound justifications.

Taking a comparison between 2019 and 2020 (AA4 to AA5), the combination of Network and Corporate opex, using the bottom-up build method, decreases by $0.5 million. The combination of Network, Corporate and IT opex between our 2019 forecast and our proposed BST 2020 forecast decreases by $2.8 million, due to the efficiencies encompassed in the BST method. Our UAFG and Ancillary Services are forecast specifically through a bottom-up method. UAFG proposed forecast is lower than our 2019 forecast by $0.5 million. Ancillary Service costs increase by $1.4 million from 2019 to 2020 due to the inclusion of special meter reading and an overhead proportion applied to capture indirect costs into the Ancillary Services unit rate.

In the following sections, we have provided additional explanation on the nature of the activities in each of the cost categories, and how we will continue to be prudent and efficient over AA5.

### 11.7.1 Network opex

Our AA5 network opex forecast using the bottom-up forecasting method is **$188.7 million**. Network operating costs are made up of network maintenance and network control and operations support (see below for further information).

Our network opex costs are aligned with our Asset Management System (including our ALSs) and Risk Framework (encompassing our GDS and Mandurah Gas Lateral Safety Case). Our AMP and ALSs are designed to reduce the life cycle costs of assets while maximising asset performance and reducing risk to as low as reasonably practicable (**ALARP**).

Network opex is forecast using a combination of historical unit costs, market-tested rates and forecast resource requirements to deliver the services to our growing customer base. The works program is delivered using a combination of our internal workforce, external suppliers, and contractors to ensure that efficient and lowest sustainable cost activities, projects and work program resources are maintained over the long-term.

Our resource requirements are reviewed annually and are based on operational activities, our works program and projected network growth. The Strategic Delivery and Resource Plan identifies the strategy and outcome for this review including:

- our plans to address current and emerging issues impacting operational and project delivery; and

- opportunities for enhancing delivery of projects and operational activities for a safe, reliable, cost-efficient, environmentally sensitive and customer-focussed gas service.

Further information on how costs are determined, and how program delivery is carried out, is provided in Attachment 12.49" *'Unit Rates Forecast*' and Attachment 12.12: '*Strategic Delivery and Resource Plan*'.

- **Network maintenance:** Network opex costs include variable volume network maintenance that is forecast using a dedicated unit rate (refer to Attachment 11.2: '*Unit Rates Forecast*'). This maintenance involves preventative, corrective and reactive maintenance activities as outlined in the AMP. Network maintenance also includes management, supervision and unallocated costs associated with asset inspections and maintenance, the provision of 24/7 operations and network emergency response across the geographic footprint of the network, network repairs, installation inspections, and third-party damage prevention activities. Specific projects that are not forecast using a dedicated unit rate include our third-party damage prevention programs (such as DBYD), meterset painting, and asset sampling studies.
- **Network control and operations support:** Our Network Control and Operations Support teams ensure planning, scheduling, customer liaison and emergency management activities occur in conjunction with current procedures efficiently and effectively. Network control costs are associated with the operation of the 24/7 control room, planning and dispatch functions including daily delivery of data to the retail market. Network control opex also includes the additional costs of asset management, engineering and technical compliance functions including training and health safety and environment management, and operational costs associated with the Jandakot Operations Centre, other operational depots, fleet, and equipment.

### 11.7.2 Corporate opex

Our AA5 corporate opex forecast using the bottom-up forecasting method is **$91.4 million**. Our forecast is based on each business unit identifying the resources and support required to deliver our network and business objectives for AA5. The costs are estimated based on previous costs and known information about changes in costs and business objectives.

Corporate opex includes the costs that are associated with enterprise-wide needed support functions to serve internal (and sometimes external) customers and business partners. The support functions are provided locally where the expertise and capacity exist or through our corporate support services. Our AA5 opex costs cover the following support functions:

- **Human resources:** These are the costs associated with providing employee-related functions, including human resource strategic policy development, recruitment, workforce planning, workforce legislation compliance, industrial relations, payroll, and training and development.
- **Finance:** These are the costs associated with providing financial related support, including day-to-day financial transactions, regulatory and legislative compliance, the development and management of financial controls, financial accounting and reporting, accounts payable and receivable, debt collection, financial or treasury advice and the preparation of relevant financial statements.

- **Legal and regulatory:** Legal and regulatory costs include the provision of in-house general legal support across the business and the management of all external legal matters. Legal support services include the engagement and management of external lawyers as required, commercial disputes, network incident investigation, drafting and reviewing agreements, and legal advice regarding contract management. Regulatory costs are those associated with managing and reporting on compliance obligations, risk and servicing the access arrangement process (including tariff variations), cost pass through processes, review of business cases and investment decisions, reporting on business performance, managing and reporting on compliance obligations and oversight of regulatory arrangements to ensure appropriate ring fencing. These costs will increase in 2023 and again in 2024 due to the increased requirements associated with the AA6 process.
- **Executive, administration and governance:** These are the costs associated with the President and Executive oversight and management of our business. This function includes the development of business strategy and delivery of business plan objectives, analysing investments and business structures, evaluating performance against annual operating and capital budgets, and Board management and business processes.
- **Risk and Compliance:** These are the costs associated with operational, financial and compliance audits and risk management. A robust internal risk and compliance function is important and a standard component of large organisations. Risk and compliance costs include risk reporting to a dedicated audit director, monitoring of noncompliance or breaches of our obligations, support on matters of security, coordination of insurance renewals, crisis and contingency management, and business continuity planning.
- **Fees and Insurance:** Insurance costs and fees are those involved in managing the ATCO Group insurance and corporate membership programs. Insurance is of important to entities with large capital investment. The purchase of external insurance is a standard corporate practice to mitigate risk and enable the timely repair to property and equipment in the event of damage. This supports the delivery of a reliable service.
- **Corporate Affairs, Marketing, and Communication:** Corporate communication costs are for internal and external communication services, website content management, and event and incident communication. Our marketing team supports network operations through delivery of safety awareness and education through direct industry focussed initiatives as well as other targeted and mass media marketing including Safety Awareness Marketing, community engagement through the Blue Flame Kitchen, and community projects.

### 11.7.3 Information technology (**IT**) opex

IT opex is developed from the IT Asset Strategy[50]to efficiently and effectively manage the maintenance and replacement of IT assets. The IT Asset Strategy also identifies specific projects to support the growth of the business, meet Safety Case and network asset management requirements and deliver improved productivity in network and corporate operations.

Our bottom up IT costs are forecast by undertaking a review of the network and business requirements over the period. As part of our AA5 submission we have developed our IT Asset Strategy to deliver these requirements. Our cost estimates are based on a combination of historical costs and information about changes in costs and new costs relating to technology improvements.

We have forecasted IT costs of $49.9 million in AA5, however approximately $10.8 million relates to Corporate and Network costs (e.g. departmental running costs). The forecast $39.1 million relates to our

[50] Attachment 12.13: '*IT Asset Strategy*'

IT department running costs, our third-party service provider charges (‘managed services’), and software licencing.

Our **IT function** includes developing and delivering the IT strategy, managing IT contracts, ensuring disaster recovery support and business continuity plan requirements are up-to-date, IT investment governance, and the storage, archive and retrieval of business information. To ensure delivery of the ITAS, we have recognised that further expertise is required in our IT department; the increase in subject matter expertise will support business analysis of technical solutions and ensure ongoing delivery of system enhancements and new technologies.

**Managed services** are provided by a third-party service provider. These services include 24/7 support of telecommunications, network servers, security monitoring, applications, desktop support of ATCO’s systems, incident management, back-up, disaster recovery and business continuity planning readiness. The opex includes the Managed Services Fee that ensures that our IT system undergo the required lifecycle upgrades and replacements as per our agreed level of service.

The **software licences** cover all vendor provided software used by ATCO. In keeping with industry standards, vendors charge a fee (on a per user basis) and an annual maintenance fee. We are instituting new applications and integrating these new applications with existing applications (e.g. Geospatial Information System mapping software, Field Mobility and SAP modules). These new applications will be accessed by a larger number of employees, and as such, licence fees have increased for AA5.

# 12. Forecast capital expenditure

**CHAPTER HIGHLIGHTS**

1. We are proposing to invest $509.3 million of capital over AA5. This is $12.2 million (2%) above the capex incurred during the five and a half years of AA4.
2. Major programs (mains replacement, network expansion, security of supply, network monitoring and meter replacement) represent over 75% of our total capex.
3. Support for our major capex programs was overwhelmingly positive in the Engage Phase of the VoC, with an average support rate of 95% from our residential and SME customers.
4. Our capex forecasts use a 'bottom-up' forecasting approach for each capex driver category (sustaining the network, growing the network, IT, and structures and equipment).

## 12.1 Introduction

Capital expenditure (capex) is incurred to connect new customers to the network and to support the ongoing safe and reliable natural gas supply to our customers. This chapter outlines our forecast capex over AA5 and the method used to forecast capex.

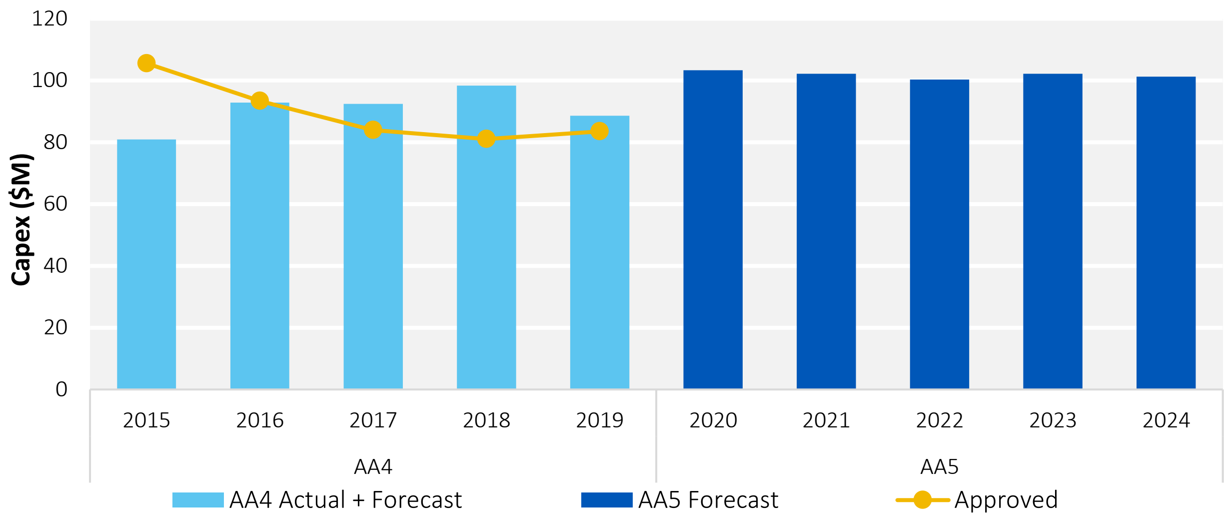
## 12.2 Regulatory framework

ATCO is required under the NGR to provide a forecast of '*conforming capital expenditure'* for AA5. Pursuant to NGR 79(1)(a), conforming capital expenditure is expenditure that would be incurred by a prudent service provider acting efficiently and in accordance with accepted good industry practice to achieve the lowest sustainable cost of providing services to its customers. Conforming capex must also be justifiable using other criteria detailed in the NGR, including meeting customer demand, safety performance, and network reliability. We submit that all the projects detailed in this chapter will meet the conforming capex test set out in the National Gas Rule 79.

## 12.3 Overview

During AA5, we propose to invest $509.3 million of capital, which is $12.2 million (2%) above the capex projected for the five and a half years of AA4. Figure 12.1 compares our actual and forecast capex across AA4 and AA5.

**Figure 12.1:** AA4 vs AA5 capex ($M real at 31 December 2019)




Our capex is driven by:

- **Sustaining the network (‘*network sustaining*’):** This involves maintaining and improving the safety and integrity of services, complying with regulatory obligations, and ensuring we can meet *current* levels of demand for services from our customers.
- **Growing the network (‘*network growth*’):** This involves complying with regulatory obligations and ensuring we can meet *forecast growth* in demand for services through expansion of the network.
- **Information technology (IT):** This involves IT systems at an operational and corporate level that enable us to provide services to customers and more strategic initiatives such as the digital transformation of our business.
- **Structures and equipment:** This involves expenditure to maintain and replace fleet vehicles (e.g. heavy and light vehicles), plant (e.g. trailers, excavators, compressors) and property (e.g. facilities, depots).

Table 12.1 provides a summary of our forecast capex over AA5, with a breakdown of expenditure by category.

**Table 12.1:** Forecast AA5 capex by capex driver ($M real at 31 December 2019)

| CATEGORY | 2020 | 2021 | 2022 | 2023 | 2024 | TOTAL |
|---|---|---|---|---|---|---|
| **Network sustaining** | **56.9** | **53.3** | **55.8** | **57.7** | **52.6** | **276.1** |
| Asset replacement | *34.6* | *37.7* | *40.4* | *37.3* | *38.1* | *188.0* |
| Asset performance and safety | *22.3* | *15.6* | *15.4* | *20.4* | *14.5* | *88.1* |
| **Network growth** | **33.8** | **34.1** | **34.9** | **35** | **36.5** | **174.3** |
| Customer-initiated | *32.8* | *34.0* | *34.4* | *35.0* | *36.4* | *172.6* |
| Demand-related | *1.0* | *0.1* | *0.5* | - | *0.1* | *1.7* |
| **Information technology** | **7.4** | **8.8** | **6.4** | **5.5** | **8.0** | **36.1** |
| **Structures and equipment** | **5.3** | **6** | **3.2** | **4.1** | **4.3** | **22.7** |
| Fleet | *3.6* | *4.7* | *1.9* | *3.0* | *3.2* | *16.3* |
| Facilities, plant and equipment | *1.7* | *1.3* | *1.3* | *1.1* | *1.1* | *6.5* |
| TOTAL | **103.4** | **102.2** | **100.4** | **102.2** | **101.3** | **509.3** |

Further detail on this expenditure is provided in Sections 12.6 and 12.8.

## 12.4 Stakeholder engagement

Our forecast capex for AA5 considers the findings from the Engage Phase of our VoC program. As outlined in Chapter 4, we obtained customer feedback on four of our major capex programs. Support was overwhelmingly positive, with an average 95% support rate from our residential and SME customers, recognising the respective contribution to the distribution cost increase:

- Mains replacement: 100% support rate
- Network expansion: 91% support rate
- Network monitoring: 91% support rate
- Meter replacement: 96% support rate

Our Draft 2020-24 Plan, released for stakeholder comment in May 2018, contained several questions relating to our proposed capex forecasts. Stakeholders were generally positive about our capex programs, with some specific suggestions and requests for more information. This feedback, along with our considered responses, is outlined in Table 12.2.

**Table 12.2:** AA5 capex: stakeholder feedback and our response

| DRAFT PLAN QUESTION | STAKEHOLDER FEEDBACK | OUR RESPONSE TO FEEDBACK ON OUR DRAFT PLAN |
|---|---|---|
| Do you believe our capex forecasts are fair and reasonable? Do you believe the 'bottom-up' method of forecasting is an appropriate method? | **Retailer B** notes the increase in capex of 9% between AA4 and AA5 and comments that ATCO needs to ensure it is in a position to actually undertake the level of work proposed. | Our forecast capex for AA4 is $497.1M - 2% less than our proposed capex of $509.3M in AA5. Our Strategic Delivery and Resource Plan (*see Attachment 12.12)* has been drafted to ensure the capex program is achievable. |
| | **Retailer A** recommends that "ATCO discuss changes to the heating value allocation with AEMO, who have recently developed and introduced a dynamic heating value allocation model for use with interval meters that have hourly heating values applied. ATCO should consider whether a more rapid heating value allocation will benefit interval meters as part of the gas chromatographs GC and SCADA development." | Heating value allocation is being reviewed as part of the Supervisory Control and Enhanced Data Acquisition program. We will continue to look for better customer solutions, providing better billing mechanisms and data transfer. The projects proposed in AA5 provide the capability to deliver and support these developments. |
| Do you support the findings from our Voice of Customer program on capex program priorities? | **Retailer A** would like further information before it can support a high level of mains replacement given the material cost effect on consumers. Retailer A questions the scale of the mains replacement program given the current low level of gas leaks, and 'Medium' risk rating, and asks whether this could be achieved without increasing the level of resources. | During AA5, we propose to replace approximately 60km of mains per year. This is a similar level of mains replacement achieved in AA4. The unit rate of replacement of PVC is forecast to remain on par with replacement rates in AA4. The 305km proposed for AA5 is considered 'Intermediate risk non-ALARP'. It is prudent for us to replace this volume of mains without increasing the level of resources. |
| | **Retailer D** welcomes the stated intent to upgrade the ATCO billing system but has requested more detail on the specifics of the proposed program. | Details on our intent to upgrade the billing system are provided in the ITAS and Application Renewal business case (*see Attachment 12.17*) |

| DRAFT PLAN QUESTION | STAKEHOLDER FEEDBACK | OUR RESPONSE TO FEEDBACK ON OUR DRAFT PLAN |
|---|---|---|
| Are there any areas of focus for our capex program that you disagree with? | Both **Retailer B** and **Retailer D** submitted a request for more information on the Information Technology program proposed for AA5, particularly in relation to the automation and system improvement initiatives that are planned to improve service delivery to retailers and customers. | Further details on our proposed IT capex and specific programs are provided in the IT Asset Strategy document and related business cases (*see Attachments 12.13, 12.14, 12.15, 12.16, and 12.17*) |
| | **Retailer B** and **Retailer A** highlighted issues they faced regarding the MIRN[51] database – specifically relating to data inaccuracies. **Retailer A** is seeking a rule change to the WA Retail Market Procedures to enable a complete MIRN database to be accessible to all participants in the WA gas market. | ATCO is committed to working with market participants to minimise addressing issues and supports the AGL GMIS submission to AEMO. We will publish the MIRN catalogue compliant with the WA Procedures 2.0 rule changes as part of the Energised and Responsive Customer Engagement program. In the absence of civic addressing standards in Western Australia, we will continue to work with retailers so that addressing issues are minimised, and investigations are handled most efficiently and cost-effectively for customers. Process and technology improvements are outlined in the Energised and Responsive Customer Engagement program business case (*see Attachment 12.14*). |
| | **Retailer A** notes "With the increased introduction of remotely read electricity meters, consumers are now seeking greater information and insight into gas usage at a more discrete level (daily or hourly). Has any consideration been given to the introduction of 'smart' gas meters in the ATCO distribution areas?" **Retailer B** supports the proposed smart meter project and encourages ATCO to work together with retailers to ensure the best outcome for customers. | During AA5, we are proposing to invest in automated meter reading (**AMR**) infrastructure. We consider it more prudent to introduce AMR in areas with difficult meter reads such as high-rise and gated buildings and high-density locations. This project is mainly to aid the billing system. Part of this project is to work with the retailers to ensure the best outcome for the customer. (*see Attachment 12.55*). |

## 12.5 Development of the capex program

Our capex forecasts use a 'bottom-up' forecasting approach for each capex driver category. Forecast capex is consistent with our overarching AMP (*see Attachment 12.1*) and ALSs (*see Attachments 12.01 – 12.08*), outlining our planning, approval, and governance processes for forecasting capex.

### 12.5.1 Cost forecasting

Our cost forecasting approach uses the following processes and principles:

- a unit rate multiplied by volume; or
- discrete projects detailed in business cases; or

[51] MIRN: Metering Installation Registration Number

- the most recent actual information available (that reflects revealed efficient expenditure); or
- the most recent tender and contract information available, reflecting the expected market costs over AA5.

We have incorporated labour cost escalation into our capex forecasts. The labour cost escalators we have adopted are identical to the labour cost escalators detailed in Section 11.6.4.

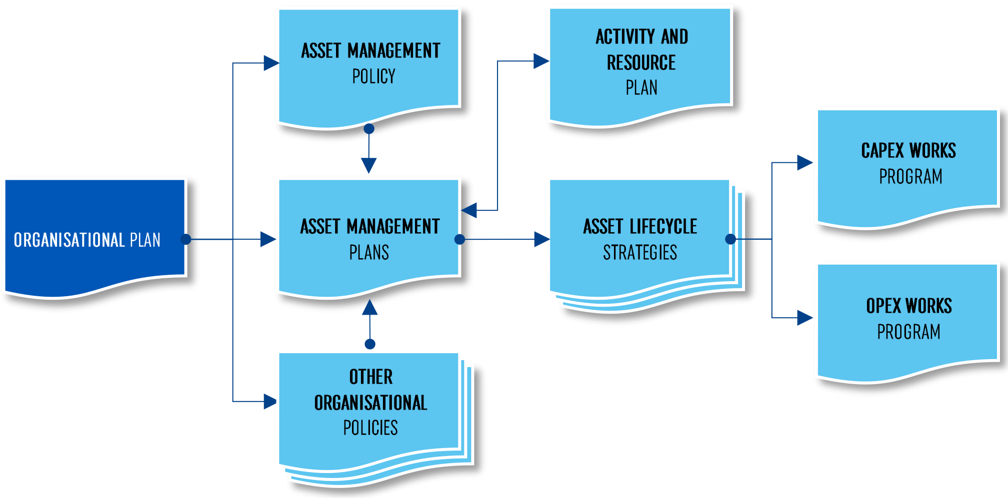
We have used our historical unit rates in our forecast. The unit rates include cost-efficiencies from the contractor rates implemented in 2016. For more information, please refer to the Attachment 12.49: *'Unit Rates Forecast'*.

These forecast methods ensure that actual and forecast capex satisfies the NGR, including that capex is prudent, efficient, and consistent with good industry practice to achieve the lowest sustainable cost for our customers.

### 12.5.2 Asset management systems

We have developed our capex proposal for AA5 in line with our asset management systems. These systems govern the scope, timing, and approach to undertaking investment and upgrades to our assets. These include critical business information systems and asset replacement and augmentation programs that maintain network safety, meet our regulatory obligations, and maintain our service performance. Figure 12.2 illustrates our asset management document hierarchy.

**Figure 12.2:** Asset management document hierarchy




ATCO integrates risk management into day-to-day decision making. We have adopted the International Standard for Risk Management ISO 31000:2009 as a benchmark to establish, implement, and maintain our risk management framework. A 'top-down' and 'bottom-up' view is taken towards the implementation of the risk management framework and involves assessing risks from different stakeholder perspectives and risk types.

As part of our Safety Case[52] and the AMP, we have conducted formal safety assessments for all asset classes to inform the development of ALSs. Through this process, we have identified the following actions to reduce network risk to ALARP:

[52] ATCO Gas Australia, *Gas Distribution System Safety Case*, December 2017

- Upgrade HP pipelines to facilitate in-line inspection to ensure pipeline integrity.
- Continue the PVC[53] mains replacement program to reduce intermediate risk (non-ALARP) rated mains to ALARP.
- Install HP pipelines, interconnections, or other suitable infrastructure (as deemed optimal via options analysis) to provide security of supply to customers.

Ongoing projects addressing network risk will continue into AA5. These include replacement of mechanical fittings, installing step touch protection, and meter compliance rectification works within the Perth CBD.

## 12.6 **Forecast capex:** Summary

Table 12.3 provides an overview of the forecast capex associated with each capex driver category, including our forecasting method. This section provides further detail on our capex forecasts for AA5.

**Table 12.3:** AA5 forecast capex by cost driver ($M real as at 31 December 2019)

| COST DRIVER CATEGORY | AA5 ($M) | AA5 (%) | COMMENT |
|---|---|---|---|
| **Network sustaining** | **276.1** | **54.2%** | |
| Asset replacement | *188.0* | *36.9%* | The mains and meter replacement programs make up over 80% of our asset replacement.<br>For mains replacement, we propose to replace 305km of our PVC network that has been identified as Intermediate Non-ALARP.<br>Meter Replacement is an ongoing compliance requirement to periodically replace residential and commercial meters to maintain reliable and accurate metering to end-use customers in accordance with the *Gas Standards (Gas Supply and System Safety) Regulations 2000* (**GSSSR**). |
| Asset performance and safety | *88.1* | *17.3%* | The 'Security of Supply' and 'Supervisory Control and Enhanced Data Acquisition' programs make up over 70% of our asset performance and safety sustaining capex.<br>We are proposing three security of supply projects to maintain current levels of reliability of supply to all customers.<br>In the Supervisory Control and Enhanced Data Acquisition program, we are proposing to enhance network management where improved data acquisition and deployment of supervisory control will deliver greater functionality and network efficiency. |
| **Network growth** | **174.3** | **34.2%** | |
| Customer-initiated | *172.6* | *33.9%* | Network expansion projects will install new mains and services to connect an average of 16,000 new customers per year in AA5. |
| Demand-related | *1.7* | *0.3%* | We have identified areas of our network that require reinforcements by installing new mains, High Pressure Regulators or Medium Pressure Regulators to maintain security of supply to customers. |
| **Information technology** | **36.1** | **7.1%** | IT capex is driven by operational priorities, vendor announcements and compliance requirements. |
| **Structures and equipment** | **22.8** | **4.5%** | |
| Fleet | *16.4* | *3.2%* | Fleet is required to continue to provide services to our customers. Our forecast is aligned to our workforce plan to deliver the proposed program of work. |

[53] Unplasticised polyvinyl chloride. All references to PVC mains on the ATCO network refer to *unplasticised PVC.*

| COST DRIVER CATEGORY | AA5 ($M) | AA5 (%) | COMMENT |
|---|---|---|---|
| Facilities, plant and equipment | *6.4* | *1.3%* | We have identified several minor facility improvement initiatives for the seven facilities located in the Perth metropolitan and regional area. These initiatives are spread across the five years.<br>Plant and Equipment is required to provide services to our customers and includes the replacement of necessary tools and equipment used by our field staff to undertake their duties. |
| **TOTAL** | **509.3** | **100.0%** | |

We have reflected the outcomes of our customer and stakeholder engagement program throughout our capex proposal, particularly regarding the initiatives that are aimed at improving network safety, security, and maintaining current levels of reliability.[54]

We have tested and refined our capex plans with our customers and stakeholders through:

- Direct engagement during the strategic planning and development process; and
- Consulting on our 2020-24 Draft Plan, which set out, in the context of our overall proposal, our forecast capex, the approach taken to developing this forecast, and the main projects to be undertaken.

As outlined in Chapter 4 of this 2020-24 Plan, customers and stakeholders were generally supportive of our approach to forecasting capex and how stakeholder feedback had been incorporated into our proposal.

Some stakeholders asked us to provide additional information on specific aspects of our capex proposals in the 2020-24 Draft Plan, such as the billing system upgrade and the mains replacement program. Where appropriate, we have included this extra information in this proposed 2020-24 Plan or linked to supporting documents in our AA5 submission.

## 12.7 Forecast capex: Network sustaining ($276.1M)

### 12.7.1 Mains replacement program ($127.4M)

BACKGROUND:

Keeping the gas flowing safely and affordably to our customers remains our priority. A critical part of this role is our Mains Replacement Program. Deteriorating mains pose a risk to customers and the public due to the potential for gas leaks to track into buildings, leading to a potential ignition event.

Our long-term mains replacement program involves the removal of low pressure cast iron, low and medium pressure unprotected steel and unplasticised polyvinyl chloride (**PVC**) mains from our networks. We have prioritised and completed the replacement of all cast iron and metallic mains in AA4.

Over AA5, this program will continue to replace PVC mains (identified as an unacceptable risk) with polyethylene (**PE**) mains. The program is essential to reduce the risk associated with these ageing assets to ALARP.

Our network consists of 9,600kms (approximately 70%) of PVC mains, introduced to the network in the early 1960s. PE mains and services were introduced in 1993, and in 2003 became the material of choice consistent with prudent operators nationally and internationally. Our PVC network has higher leakage rates than PE, predominantly occurring from fittings such as tapping bands, service tees, mechanical

[54] Further information on our customer and stakeholder engagement program (the Voice of Customer program) is provided in Chapter 4 of this 020-24 Plan.

fittings, and mechanical couplings. Leak rates increase as the material ages and deteriorates due to PVC becoming brittle over time, leading to fracture and failure of pipe.

INVESTMENT DRIVERS:

Capex for mains replacement is driven by asset condition and its associated risk rating.

To predict the condition and risk, we use a software application known as the Mains Replacement Prioritisation tool. This software considers asset specification (such as age), historical leak data (including from fittings and exposure criteria to estimate pipe condition), remaining useful life, and risk from each pipeline to the public. The semi-quantitative risk outcomes from the Mains Replacement Prioritisation tool reflect the risk to public safety (the probability of individual fatality per km per year) from each pipeline segment and have been correlated to the ATCO Risk Management Matrix, in accordance with our Safety Case[55](see Attachment 12.11).

The correlation is in line with good industry practice for tolerance of Individual Risk (measured by the risk of one fatality per annum). Further explanation of this correlation is provided within TCO GL0001 Technical Compliance Risk Management Guideline which is in line with international standard.

Table 12.4 outlines our mains risks and associated treatment for AA5. The output of our Mains Replacement Prioritisation tool has identified that 1,890km of the PVC mains have an 'Intermediate' risk, correlating to a probability of fatality per km per year between $10^{-4}$ and $10^{-6}$. Within this risk bracket, 171 km sits within the 'Upper Intermediate' region (risk of fatality per km per year between $10^{-5}$ and $10^{-4}$) and will be prioritised for replacement during AA5 due to its potential to move towards, or into, the 'High' risk category. All High risk PVC mains will be replaced in AA4.

An additional 106 km has been selected for replacement during AA5, as these pipelines have a predicted leak rate higher than the average leak rate of the intermediate zone. These pipeline segments typically interconnect segments of pipelines planned for replacement and share a similarly poor condition and predicted leak rate. An additional 10% of mains length is predicted to be replaced to achieve program efficiencies, bringing the total proposed PVC mains replacement program for AA5 to 305 km. We consider that the proposed replacement program is consistent with our obligations under the relevant standard, Australian/New Zealand Standard 4645 (AS/NZS 4645); prudently managing risk on our network to ALARP.

**Table 12.4:** Mains risk treatment

| CATEGORY | AS OF END OF 2017 | | RISK TREATMENT | TO BE REPLACED IN AA5 | |
|---|---|---|---|---|---|
| | KMS | RISK RATING | | KMS | RISK RATING |
| PVC with the probability of fatality per km per year between $10^{-5}$ and $10^{-4}$ | 171 | Intermediate *'Upper-Intermediate'* | Replace as part of a mains replacement program | 171 | Low* |
| PVC with predicted leak rate higher than the average leak rate of the intermediate zone | 106 | Intermediate *'Lower-Intermediate'* | Replace as part of a mains replacement program | 106 | Low* |
| PVC with the probability of fatality per km per year between $10^{-6}$ and $10^{-5}$ | 1,613 | Intermediate *'Lower-Intermediate'* | No additional risk treatment proposed | 0 | Intermediate |

55 ATCO Gas Australia, *Gas Distribution System Safety Case*, December 2017

| CATEGORY | AS OF END OF 2017 | | RISK TREATMENT | TO BE REPLACED IN AA5 | |
|---|---|---|---|---|---|
| | KMS | RISK RATING | | KMS | RISK RATING |
| PVC with the probability of fatality per km per year less than $10^{-6}$ | 7,676 | Low | No additional risk treatment proposed | 0 | Low |
| **TOTAL as per risk assessment from the mains replacement tool** | | | | **277** | |
| Additional PVC as part of bundled works | N/A | Not Applicable | Cost-efficient to replace under the program | 28 | |
| **TOTAL as per Mains Replacement Program** | | | | **305** | |

*although risk has effectively been removed as there is no PVC remaining.

Our mains replacement forecast includes service renewals. We replace these assets as we deliver our mains replacement program due to the safety and cost benefits of doing so, rather than as a stand-alone activity. This approach is consistent with current practice.

This replacement strategy aims to reduce the Intermediate PVC risk to ALARP over AA5. We are conducting an ongoing sampling and testing program (opex) to gather additional condition data of PVC in the network and help to further enhance prioritisation of the Mains Replacement Program and inform our future PVC replacement decisions. This sampling and testing program will prioritise expenditure to achieve the highest risk reduction.

The Mains Replacement Program satisfies the NGR 79 (2)(c)(i); the capex is necessary to maintain and improve the safety of services. The proposed replacement of 305 km out of 1890 km of Intermediate risk PVC mains over AA5 was deemed to be a quantity that reduces risk to ALARP. Replacing ageing and leaking PVC mains with a fully fused solution reduces the likelihood of a gas leak that may result in leak tracking, accumulation within a building, ignition, and up to two fatalities. It also meets (2)(c)(ii) where the capex is necessary to maintain the integrity of services. The replacement of PVC mains with PE mains will reduce the risk of asset failure, thereby reducing reactive maintenance costs, improving the integrity of the network, and reducing the potential for impacts to customers.

PLANNED ACTIVITY:

We are forecasting to spend $127.4 million on replacing 305km of mains in AA5. The average of 60kms replacement per year is consistent with the volume achieved in AA4.

Table 12.5 outlines the total length of mains to be replaced over AA5.

**Table 12.5:** Mains length to be replaced in AA5 (km)

| TYPE | 2020 | 2021 | 2022 | 2023 | 2024 | TOTAL |
|---|---|---|---|---|---|---|
| PVC mains replacement[56] | 59 | 63 | 63 | 60 | 60 | **305** |
| **TOTAL** | **59** | **63** | **63** | **60** | **60** | **305** |

[56] This is subject to change due to the continuous refining of the Mains Replacement Prioritisation model.

FORECAST EXPENDITURE:

A total of $127.4 million of network sustaining capex has been estimated for the Mains Replacement Program for AA5, as summarised in Table 12.6.

The project cost estimates were calculated using unit rates for each main type and an assessment of the costs resulting from geographical characteristics of the mains' location. Our forecast unit rates are based on and supported by the outcomes of our competitive tender processes. We also considered bundled efficiency, new delivery methods, mobilisation, disruption, and third-party combined works opportunities. We believe that our unit rate forecasts ensure our forecast capex is a best estimate. The unit rate is consistent with the lowest sustainable cost of replacing the required volume of mains over AA5 and therefore satisfies the requirements of NGR 79(1)(a). Our mains replacement capex accounts for 25% of our total capex over AA5.

**Table 12.6:** Mains replacement program in AA5 ($M real at 31 December 2019)

| PROJECTS | 2020 | 2021 | 2022 | 2023 | 2024 | TOTAL |
|---|---|---|---|---|---|---|
| **NETWORK SUSTAINING CAPEX** | | | | | | |
| PVC Mains Replacement | 23.5 | 25.8 | 26.2 | 25.5 | 26.3 | 127.4 |
| **TOTAL** | **23.5** | **25.8** | **26.2** | **25.5** | **26.3** | **127.4** |

### 12.7.2 Meter replacement program ($27.3M)

BACKGROUND:

We install meters on the network for billing or network monitoring purposes (e.g. capacity modelling, UAFG calculations). While there are various types and sizes of meters on the network, each meter falls into one of two categories based on the type of meter being replaced: *domestic meters and commercial meters.*

We have a regulatory obligation under the Gas Standards[57] to manage the integrity of meters and ensure they operate within a prescribed tolerance band for metering accuracy. We are therefore required to carry out Routine Meter Changes on domestic meters, and Commercial Meter Changes on commercial meters that have reached their prescribed life or when the accuracy of their measurements falls outside the prescribed tolerance band.

INVESTMENT DRIVERS:

Capex is driven by the lifecycle stage of the particular meter. Domestic and commercial meters have an end-of-life stipulated by regulatory requirements within the Gas Standards[58] to ensure accuracy retention:

- For **domestic meters**, we replace meters at their prescribed end of life, which is 18 years. Our technical regulator *Building and Energy* (formally Energy*Safety*) approved an alternative requirement to the regulation with the extension of newer models of the domestic meters' in-service life to 25 years and replacing the expired domestic meter with a new meter.
- For **commercial meters**, an opex meter refurbishment program is maintained, to change out meters at their prescribed end-of-service life. Where we can no longer refurbish a meter (based on the manufacturer's recommendation), the meter is replaced under a capex project.

[57] As per Gas Standards (Gas Supply and System Safety) Regulations (GSSR) 2000 (Part 3 – Metering: Section 16)
[58] As per Gas Standards (Gas Supply and System Safety) Regulations (GSSR) 2000 (Part 3 – Metering: Section 16)

This program satisfies NGR 79 (2)(c)(iii), the capex is necessary to comply with a regulatory obligation or requirement. The replacement project complies with *Gas Standards (Gas Supply and System Safety) Regulations 2000 (GSSSR) (Part 3 – Metering: Section16)* which requires a network operator to ensure that all installed domestic meters are replaced at intervals not exceeding their prescribed end of life. This project will ensure that the domestic gas meter accuracy is within tolerances identified in the GSSSR by replacing the meters with new meters at the end of their in-service lives.

PLANNED ACTIVITY:

Replacement volumes are based on install date for domestic meters and commercial meters, and historical trends for network monitoring meters. Based on installation dates, we forecast approximately 25,000 domestic meter and 661 commercial meter replacements in AA5. Most of the commercial meters will be replaced with a refurbished meter under opex and we estimate 10 replacements per year under capex based on historical replacement rates.

FORECAST EXPENDITURE:

Applying the domestic and commercial meter replacement unit rates to the forecasts set out above, we have estimated that the meter replacement program will cost $27.3 million over AA5, which represents around 5% of total capex. For more detail regarding our meter replacement forecast, please refer to the Attachment 12.49: *'Unit Rates Forecast'*.

**Table 12.7:** Meter replacement program AA5 capex ($M real at 31 December 2019)

| PROJECTS | 2020 | 2021 | 2022 | 2023 | 2024 | TOTAL |
|---|---|---|---|---|---|---|
| **NETWORK SUSTAINING CAPEX** | | | | | | |
| Domestic meters | 5.2 | 4.9 | 5.3 | 5.6 | 5.6 | **26.6** |
| Commercial meters | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | **0.6** |
| **TOTAL** | **5.4** | **5.1** | **5.4** | **5.7** | **5.7** | **27.3** |

### 12.7.3 Security of supply ($49.0M)

BACKGROUND:

Security of supply projects focus on maintaining the natural gas supply to our customers following an adverse event, such as third-party damage to a pipeline. HP steel pipelines (Class 150, 300 and 600) provide the main supply conduits between the transmission and the distribution networks. Any damage to these pipelines may require isolation, and should this occur, we want to ensure there are alternative supply options to reduce prolonged interruptions.

We continue to mitigate third-party impacts to the network via the implementation and monitoring of physical and procedural controls, but the threat of third-party impact remains inherent to our gas distribution network.

INVESTMENT DRIVER:

These projects have been determined through a Supply Risk Assessment on HP steel pipelines, conducted in 2017, to understand the frequency of the loss of containment and subsequent consequence of loss of supply risk. The assessment implemented semi-quantitative analysis of the probability of third-party impacts. The supply risk consequence and associated ranking were assessed using "customer weeks lost", as per Australian Standard / New Zealand Standard 4645.1:2018.

'High' or 'Intermediate' rated risks must be subject to treatments that reduce the risk to an acceptable level in accordance with our Risk Management Framework and our Safety Case[59]. This will ensure the supply of gas to customers is reliable, and prolonged interruptions of supply are minimised. The risk assessment identified that 11% of these pipelines are considered 'High' risk[60].

Our security of supply projects satisfies NGR 79 2(c)(ii); the capex is necessary to maintain the integrity of services. The capex is required to avoid a major gas outage and to maintain the integrity of services and reduce supply risk to an acceptable level.

FORECAST ACTIVITY:

We have considered multiple options for improving security of supply, including reinforcement pipelines and assets, virtual pipelines, physical pipeline protection, increased operational activities, and segmentation of the network through the installation of actuated valves with SCADA control.

Following a detailed analysis of the options, we identified three security of supply projects for AA5:

- Security of Supply – Bunbury
- Security of Supply – Caversham
- Security of Supply – Two Rocks

'Security of supply' projects focus on **ensuring the natural gas supply can be maintained** to our customers following an adverse event, such as third-party damage to a pipeline .

These projects will entail the use of reinforcement pipelines and auxiliary pressure reduction assets and will incorporate network reconfiguration.

FORECAST EXPENDITURE:

A total of $49.0 million of network sustaining capex is forecast for security of supply projects, summarised in Table 12.8. The expenditure for each project was forecast based on recent actual costs of similar projects. This program makes up 10% of our total capex.

**Table 12.8:** Security of supply program AA5 capex ($M real at 31 December 2019)

| PROJECTS | 2020 | 2021 | 2022 | 2023 | 2024 | TOTAL |
|---|---|---|---|---|---|---|
| **NETWORK SUSTAINING CAPEX** | | | | | | |
| Security of Supply - Caversham | 15.0 | - | - | - | - | **15.0** |
| Security of Supply - Bunbury | - | 3.8 | 3.8 | - | - | **7.6** |
| Security of Supply - Two Rocks | - | - | - | 15.2 | 11.3 | **26.5** |
| **TOTAL** | **15.0** | **3.8** | **3.8** | **15.2** | **11.3** | **49.0** |

59 ATCO Gas Australia, *Gas Distribution System Safety Case*, December 2017

60 Based on quantitative isolation frequency estimation coupled with 'customer weeks lost' consequence modelling. Consequence categories against "customer weeks lost" were mapped to the ATCO Risk Management Matrix against category criteria provided in the draft AS/NZS 4645.1:2018, anticipated to come into effect prior to, or during AA5.

### 12.7.4 Supervisory Control and Enhanced Data Acquisition ($12.6M)

BACKGROUND:

Providing a safe and efficient gas supply relies on the proactive control and continuous monitoring of our gas pipeline network. Our proposed network monitoring capex received 91% support in our VoC program.

We rely on telemetry for monitored data to inform our decisions to operate and reinforce the network. In AA5, we are proposing to invest in three projects:

- **SCADA Systems and Infrastructure**: This project will introduce automation of the network to operate the network more effectively through remote control of gas flows and pressures. We require remote control capability to reduce emergency management risk and improve operation of the GDS.
- **Enhanced data acquisition**: This is a continual improvement project to improve monitoring of gas quality (heating values, odorant levels and other gas characteristics) through constant monitoring. This is an important control for the safety of the gas network and is vital to ensure the affordability of gas for our customers. This project will also enhance condition assessment through the remote monitoring of cathodic protection equipment and medium pressure regulator sets allowing faults to be identified earlier and enable improved data for dynamic modelling.
- **Automated meter reading (AMR)**: This project introduces remote meter readings for gas customers in harder-to-access locations such as high-rise or gated buildings. This enhances options for customers, builders, developers and retailers to ensure gas remains a valuable energy choice.

INVESTMENT DRIVERS:

We plan to implement the Supervisory Control and Enhanced Data Acquisition program to reduce emergency management risk and to improve the operation of the gas network.

Our investment will improve our ability to control and monitor the network remotely. The ability to remotely control equipment and resolve issues enables us to make better use of our assets and extend asset life.

By increasing the remote monitoring of assets and improving our data capture, our staff can be deployed more efficiently during emergencies. We will have greater visibility of asset condition, which can optimise our investments in capacity upgrades or asset replacement. Another driver is to identify faults and outages more accurately and have the capability to resolve the issues remotely.

Main drivers for implementing the Supervisory Control and Enhanced Data Acquisition program include:

- Network growth at the extremities as well as infill growth.
- Improved consistency in network operation and fringe pressures.
- Reduced network risks.
- Regulatory compliance.
- Improved operating efficiency through greater automation.

The three projects covered under Supervisory Control and Enhanced Data Acquisition program meet the requirements of the NGR 79:

- **SCADA Systems and Infrastructure**: This project involves introducing remote network isolation which increases the effectiveness of emergency isolation to increase public safety and reduce loss of supply events and therefore meets NGR 79 (2)(c)(i).

- **Enhanced data acquisition**: The capex will ensure that network pressures and the integrity of assets are maintained, and therefore meets NGR 79 (2)(c)(ii). An important part of this project is odorant monitoring. This initiative mitigates the risk of delivery of non-odorised gas into the GDS as required under the compliance to the GSSSR. This project also meets NGR 79 (2)(c)(iii), in that the capex is necessary to comply with a regulatory obligation or requirement.
- **AMR**: AMR enables remote meter locking for identified customers to meet retailer isolation expectations and safety of personnel attending site. This project meets NGR 79 (2)(c)(i) to improve the safety of services. The AMR also enables us to meet the majority of our compliance obligations against the AEMO Market Procedures (including interval metering and reducing estimated reads) and therefore meets NGR 79 (2)(c)(iii).

PLANNED ACTIVITY:

This program consists of five areas to enhance network management where improved data acquisition and deployment of supervisory control will deliver greater functionality, network efficiency and improved management of the gas network:

- **Remote network isolation:** This initiative increases operational efficiency by the ability to operate networks remotely in emergencies.
- **Automated network pressure control:** This initiative will introduce SCADA to remotely control pressures to optimise network reinforcement, minimise network losses, and improve network operation and fringe pressures.
- **Constant monitoring of gas quality:** This initiative improves gas quality management systems and increases network safety.
- **Remote monitoring of corrosion protection systems:** This initiative enables earlier dispatch of maintenance personnel to rectify problems and hence extend the asset life.
- **Enable AMR – at unique locations:** This initiative supports the construction and development industry to deliver innovative solutions for WA residents

FORECAST EXPENDITURE:

We estimate a total of $12.6 million of network sustaining capex for the Supervisory Control and Enhanced Data Acquisition program, as summarised in Table 12.9. This program makes up 2% of our total AA5 capex. This expenditure is consistent with the finding that customers are supportive of initiatives that maintain reliability and improve the safety of our network.

**Table 12.9:** Supervisory Control and Enhanced Data Acquisition AA5 capex ($M real at 31 December 2019)

| PROJECTS | 2020 | 2021 | 2022 | 2023 | 2024 | TOTAL |
|---|---|---|---|---|---|---|
| **NETWORK SUSTAINING CAPEX** | | | | | | |
| Supervisory Control and Enhanced Data Acquisition | 2.5 | 2.5 | 2.5 | 2.5 | 2.6 | 12.6 |
| **TOTAL** | **2.5** | **2.5** | **2.5** | **2.5** | **2.6** | **12.6** |

### 12.7.5 Other sustaining capex programs ($59.8M)

#### End of life replacement ($33.6M)

- **Risers and services:** Ageing risers connected to PVC services are susceptible to leakage. Historically we have identified approximately 1,600 leaks per year on risers and services via 'smell of gas' calls from the public or during routine maintenance. We expect these volumes to increase due to increased leak survey activity in AA5 (refer Section 11.6.2.1). Therefore, we forecast to replace 2,600 risers and services per year in AA5 to eliminate these leaks. Our forecast unit rate is based on historical averages, and we estimate the project will cost **$17.7 million**.

  This project satisfies NGR 79 (2)(c)(i); the capex is necessary to maintain and improve the safety of services. This project eliminates the potential increase in leaks on services and risers by replacing with fully fused jointing solutions. The project also reduces the risk of leakage in proximity to customer properties. It also meets NGR 79 (2)(c)(ii); the capex is necessary to maintain the integrity of services. Replacement of uPVC section with fully fused PE pipe system will improve integrity by eliminating the likelihood of leaks and extending the service life of the system.

- **Regulator sets and metering facilities:** Regulator sets (including pits and lids) and commercial and industrial metering facilities (including pressure regulating, isolation equipment and meter) experience degradation in condition over time. We assess the condition of the asset during scheduled inspections. Where the condition is deemed poor, additional engineering assessment is undertaken to ascertain whether the asset requires replacement, or whether alternative refurbishment or repair options are available. However, when they can no longer meet operational requirements, they are replaced. A total of **$6.1 million** has been estimated for AA5 based on historical unit rates. The volumes are based on historical trends.

  This project satisfies NGR 79 (2)(c)(i); the capex is necessary to maintain and improve the safety of services. The project maintains safety by ensuring corroded pit lids are replaced prior to an incident occurring. It also meets NGR 79 (2)(c)(iii); the capex is necessary to comply with a regulatory obligation or requirement. This project will replace old legacy designed lids a new design that complies with the maximum lifting weight, as per our Occupational Health and Safety requirements.

- **Mechanical compression fittings:** Mechanical compression fittings are susceptible to leakage if deflection of the fittings occurs due to local ground movements or surrounding earthworks. We assessed the risk of a gas incident due to the leak of mechanical compression fittings in residential areas of the GDS Formal Safety Assessment. The assessment deemed the risk as Intermediate (Non-ALARP), and as a result, are no longer used on the network. Mechanical compression fittings are removed when identified during operational activities. **$4.5 million** is forecast in AA5 for replacement of 160 mechanical compression fittings. The forecast volume and unit rate are based on actual volumes and actual unit rates in AA4.

  This project satisfies NGR 79 (2)(c)(i); the capex is necessary to maintain and improve the safety of services by removing leaking mechanical fittings.

- **Telemetry:** We rely on telemetry monitoring to provide information on network gas flow and pressure conditions. The information is used to optimise system performance and maximise safety. The timing of replacement for this equipment is based on the average life before failure. The replacement volumes are therefore based on specific timings from the original install dates. The AA5 forecast for telemetry equipment is **$3.6 million** and includes the replacement of equipment such as data loggers and flow computers.

This project satisfies NGR 79 (2)(c)(ii); the capex is necessary to maintain the integrity of services. Through proactive replacement, we improve the reliability of telemetry flow and pressure data, which is used for distribution network operation, modelling and planning. This also improves accuracy of customer billing data and eliminates the need for manual verification.

- **Exposed pipe:** Steel pipe on bridge crossings is susceptible to corrosion and leakage over time, as identified through five-yearly physical inspections on exposed mains. Cost-benefit-analysis is conducted to determine repair vs replacement strategies for each site that requires remediation. It is recommended to replace identified steel bridge crossings with directionally drilled PE pipework (underneath the waterway). One site has been identified for AA5 and is estimated to cost **$0.8 million**.

  This project satisfies NGR 79 (2)(c)(ii); the capex is necessary to maintain the integrity of services. Decommissioning and replacing the exposed steel main with a PE main under the river, eliminates the risk of the steel main leaking and avoids the future high inspection cost and maintenance cost.

- **Cathodic protection assets:** Cathodic protection is installed to protect steel pipes from material fatigue and corrosion, which can lead to leaks or pipe blockages. All HP steel pipelines with a maximum allowable operating pressure greater than 1050 kPa require protection from corrosion. Projects that contribute to this capex category include replacement of depleted anodes, upgrade of cathodic protection enclosures to minimise third-party damage, resistance probes to identify active corrosion and insulation joints, and surge diverters to prevent damage in the event of an electrical surge. The investment driver is to provide adequate protection and conditional data on the HP steel assets and ensure public and personnel safety. The forecast volumes are consistent with volumes achieved in AA4, and expenditure forecasts are based on a bottom-up build using set material costs. The AA5 forecast for five projects associated with the replacement of cathodic protection assets is **$0.6 million**.

  This project satisfies NGR 79 (2)(c)(i) and (2)(c)(ii); the capex is necessary to maintain the safety and integrity of services. This project is to mitigate the risk of leaks from HP gas mains due to corrosion.

- **Warning signs:** HP warning signs are a control to reduce the likelihood of a third-party impact on our high-pressure assets. HP warning signs are installed on the network against sign spacing requirements for different location classes in accordance with the Australian Standard[61]. Approximately 7,500 HP warning signs will be installed on the network by the end of AA4. HP warning signs are visually inspected as part of a pipeline patrol (weekly or monthly) and may be deemed 'end of life' due to physical damage (e.g. weather, vehicular impact, or vandalism), or structural degradation (e.g. corrosion). To maintain compliance with the Australian Standard, we replace HP warning signs when they reach their end of life. Based on operational experience, we estimate that approximately 130 signs per year will require replacement due to physical damage or structural degradation and is estimated to cost **$0.3 million**.

  The project satisfies NGR 79 (2)(c)(i), the capex is necessary to maintain and improve the safety of services. Replacing warning signs will ensure third parties have a visual warning at all locations along our high pressure pipelines (regulatory requirement). This will also ensure we continue to meet our regulatory requirements as of AS2885 (NGR 79 (2)(c)(iii)).

### Parmelia Gas Pipeline (PGP) interconnection ($13.5M)

The network is currently supplied by 14 gate-stations from the Dampier to Bunbury Natural Gas Pipeline (**DBNGP**) and two gate stations supplied from the PGP. By the end of AA4, there will be one additional gate-station supplied from the PGP.

[61] AS/NZS 2885.1:2007 Pipelines- Gas and liquid petroleum-Design and construction

A 'loss of supply' event from the DBNGP could result in a catastrophic supply consequence to customers. Additional connections into the PGP pipeline will allow access to the Mondarra storage facility to mitigate the loss of gas supply in the event of isolation of the DBNGP transmission.

We propose two additional gate stations for AA5. The network sustaining capex estimated for AA5 is **$13.5 million** for the connection of the PGP in South Metro and Rockingham. This forecast is based on preliminary project estimates developed between us and APA. The forecast will be refined and reflective of the actual cost from the PGP connections currently in construction in AA4.

This project satisfies NGR 79 (2)(c)(ii); the capex is necessary to maintain the integrity of services. By introducing additional connections from the PGP into the distribution network, we will avoid major gas outages. This project also meets NGR 79 (2)(c)(iii); to ensure we comply with regulatory obligations under AS/NZS 4645.1 security of supply risks.

### Inline inspection ($9.2M)

Inline inspections have been completed as part of AA4 and are proposed to continue in AA5, with seven pipelines identified to undergo internal inspection to detect potential steel defects. In the planning process, we identified that six of these seven pipelines will require modifications to enable the internal inspection. The modification is necessary to enable the pipeline inspection gauge to be safely introduced and removed from the pipeline without obstruction. The network sustaining capex estimated for AA5 is **$9.2 million**.

This program satisfies NGR 79 (2)(c)(i); the capex maintains the safety of services by improving our ability to detect potential pipeline leakage locations, especially the locations that are currently inaccessible to DCVG surveys. It also meets NGR 79 (2)(c)(ii) because inline inspection provides the ability to detect an entire suite of pipeline anomalies to effectively maintain the integrity of services. The scope of the project ensures we can demonstrate compliance with AS2885 and therefore meets NGR 79 (2)(c)(iii).

### Network improvements ($3.5M)

- **Meter compliance:** This is an ongoing project to remediate gas meter installations that are deemed non-compliant to Australian Standards AS/NZS 4645.1, AS/NZS 5601 and the *Gas Standards (Gas-fitting and Consumer Gas Installations) Regulations 1999*. Installations within dwellings that do not have compliant meter enclosures or ventilation (and have been assessed as having an unacceptable risk), will require treatment under this project to ensure compliance with the aforementioned Australian Standards as required by our Safety Case. This project is estimated to cost **$1.4 million** over AA5.

  This project satisfies NGR 79 (2)(c)(i) and (2)(c)(ii) by mitigating the risks of danger to life and property by improving the integrity of the gas meter installation and reducing the risk of a gas release into buildings. This ensures our gas installation is complaint to AS/NZS 4645.1 and AS/NZS 5601 and therefore meets NGR 79 (2)(c)(iii).

- **Installation of 'step touch' mitigation systems:** This is an ongoing project to protect personnel from induced voltages while working on steel infrastructure. We have assessed and identified 35 pipelines as High risk and mitigation works began in 2017, with an expected completion by the end of 2029. This project is to mitigate the electrical hazard on existing assets by installing 'step-touch' mitigation systems to reduce high risk to ALARP. These systems have been designed by third-party subject matter experts. We intend to install these mitigation systems only on the high risk infrastructure and this project is estimated to cost **$1.2 million** over AA5.

  This project satisfies NGR 79 (2)(c)(i), the installation of 'step touch' mitigation systems on assets identified at risk will improve the safety of field personnel working on our HP pipelines.

- **Facility upgrade – Pressure Reduction Station (PRS) security:** Above ground PRS facilities are protected from unauthorised entry via wire mesh fencing. Unauthorised access by members of the public has occurred at some PRS sites, resulting in vandalism and theft. Intentional actions by unauthorised personnel could result in damage to assets and isolation of supply from a PRS affecting the downstream supply to customers. Based on their accessibility to the public, nine sites are selected to undergo security upgrades to palisade fencing. The capex estimated for AA5 is **$0.5 million,** based on actual unit rates provided for existing fencing upgrade projects. **Note,** the $0.5 million is captured under Facilities, Plant and Equipment capex forecast (see Section 12.11).

  This initiative maintains the safety of services by reducing the potential for unauthorised entry and potential damage or vandalism of the PRS facility. This could lead to public safety and personnel risks due to gas leaks and therefore satisfies NGR 79 (2)(c)(i).

- **Pressure monitoring devices (PMDs):** Installing PMDs to monitor the network enables us to respond quickly to emergency situations. PMDs are also important to verify the modelling results in peak conditions against the actual monitored data. This helps us in long-term planning to support capex reinforcement projects and to mitigate unforeseen gas supply interruptions due to weak pressure. Hydraulic modelling of the gas network is used to identify areas of weak pressure during peak gas usage. We prioritise capex for PMD sites by selection criteria, with the unmonitored sites and sites approaching network minimum pressure being foremost. We propose to install 30 PMDs in AA5 with a capex investment of **$0.5 million**.

  This project monitors pressures in the GDS especially at poor pressure areas are necessary to maintain the integrity of the existing services and therefore satisfies NGR Rule 79 (2)(c)(ii).

- **Vehicle protection:** Above ground facilities on the network can be damaged by vehicular impact with the potential to result in supply loss and loss of containment. Bollards and barriers are installed to protect above ground facilities from impact where a facility is not adequately protected. The sites are identified by field personnel during routine maintenance and assessed against risk-based criteria taking into consideration alignment, distance to traffic, and traffic speed. We have forecast **$0.2 million** of capex in AA5 for vehicle protection.

  This project satisfies NGR 79 (2)(c)(i) and (2)(c)(ii); vehicle protection maintains network safety by reducing the likelihood of a third-party impact to a facility, thereby preventing fatalities due to loss of containment and ignition consequences. Vehicle protection also provides protection for maintenance personnel who may be working on the asset. The capex for vehicle protection also reduces the likelihood of a supply loss due to vehicle impact.

Table 12.10 summarises our AA5 capex forecast for 'other' sustaining capex programs.

**Table 12.10:** AA5 forecast of 'other' sustaining capex ($M real at 31 December 2019)

| PROJECT | 2020 | 2021 | 2022 | 2023 | 2024 | TOTAL |
|---|---|---|---|---|---|---|
| Projects outlined above | 10.6 | 16.1 | 17.8 | 8.6 | 6.7 | **59.8** |
| **TOTAL** | **10.6** | **16.1** | **17.8** | **8.6** | **6.7** | **59.8** |

## 12.8 Forecast network growth capex ($174.3M)

### 12.8.1 New customer connections ($172.6M)

BACKGROUND:

Growth capex relates to the cost of facilitating new customer connections to our network. Most of our growth capex forecast is focussed on the cost of connecting customers in new subdivisions bordering existing areas of our network. The present value of the expected incremental revenue to be generated as a result of the expenditure exceeds the present value of the capex, therefore justified under NGR 79(2)(b).

For new connections that require major extensions, we assess these cases individually to ensure our investment is prudent. We have completed several major extensions of our network over AA4 to enable new connections in Elizabeth Quay, Byford, Vasse, Whitby, Yanchep and Two Rocks. A provision (Growth Development) is included in AA5 to capture expenditure to extend the network to enable new commercial or new sub-divisions.

We work closely with developers, home builders and other utilities to expand the use of common trenching for the installation of new residential service lines resulting in lower installation cost.

INVESTMENT DRIVERS:

Our growth capex is driven by the number of new customers we expect to connect to the network in AA5 (discussed in Chapter 9). Growth in customer numbers helps to maintain lower prices to existing customers by sharing the primarily fixed costs of operating the network across a larger customer base.

These activities satisfy NGR 79 (2)(b); the economic evaluation shows that the present value of the expected incremental revenue to be generated as a result of the expenditure, exceeds the present value of the expenditure.

PLANNED ACTIVITY:

Based on the demand forecast, we are expecting to connect:

- 81,000 new domestic customer connections with the associated new services, mains extension and new domestic meters.
- 2,300 new commercial meter installations.

The number of installations used within the forecast is based on Core's demand forecast.

FORECAST EXPENDITURE:

We have based our forecast capex on a unit cost approach; the customer growth forecast multiplied by the relevant unit rates outlined in Unit Rate Report. The cost associated with a new connection includes:

- Mains extension – the average cost of extending our network to connect the new customer.
- New service and meter installation - the average cost of installing a service and new meter equipment.

Table 12.11 shows the AA5 forecast growth capex of **$172.6 million** (34% of our total forecast capex).

**Table 12.11:** AA5 forecast capex for new customer connections ($M real at 31 December 2019)

| CATEGORY | 2020 | 2021 | 2022 | 2023 | 2024 | TOTAL |
|---|---|---|---|---|---|---|
| **NETWORK GROWTH** | | | | | | |
| Growth Domestic Forecast | 29.8 | 31.1 | 31.7 | 32.3 | 33.6 | **158.5** |
| Growth Commercial Forecast | 2.5 | 2.4 | 2.2 | 2.1 | 2.2 | **11.4** |
| Growth Development | 2.0 | 2.0 | 2.1 | 2.1 | 2.1 | **10.4** |
| **SUB-TOTAL** | **34.4** | **35.6** | **35.9** | **36.5** | **37.9** | **180.2** |
| Less Capital Contribution | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | **-7.6** |
| **TOTAL** | **32.8** | **34.0** | **34.4** | **35.0** | **36.4** | **172.6** |

### 12.8.2 Network reinforcements ($1.7M)

BACKGROUND:

The distribution network must maintain adequate capacity to safely deliver gas to customers. Minimum network pressures are required for service regulators to function and allow the safe supply of gas to appliances. In areas of the network experiencing high growth and increasing new customer connections, the ability of the network to maintain capacity may become diminished.

INVESTMENT DRIVERS:

Analysis of forecast new connections, coupled with hydraulic modelling of the gas network, has identified several expansion projects that will be required to maintain capacity during AA5. These include capacity upgrades to regulating facilities and mains extensions that maintain gas supply.

Capacity driven projects are typically planned for the *year prior* to any predicted problems with network capacity. This allows us to stay ahead of potential supply problems for customers. Investment in SCADA, (*see Section 12.7.4*), will continually improve and optimise timing for network reinforcement projects.

In addition, we use an industry standard software package known as '*SynerGi*' to model network capacity and optimise network utilisation as it grows. This software identifies when network expansion projects are required to maintain security of supply and sufficient capacity.

These projects satisfy NGR 79 (2)(b); the economic evaluation shows that the present value of the expected incremental revenue to be generated as a result of the expenditure, exceeds the present value of the expenditure.

PLANNED ACTIVITY:

The major network reinforcement projects identified for implementation during AA5 include:

- Three regulator sets as part of our reinforcement projects, with each project planned for the year prior to the network reaching system minimum pressure as identified through modelling.
- Mains extensions to address poor pressure problems.
- Four regulator sets requiring capacity upgrade.

FORECAST EXPENDITURE:

We forecast **$1.7 million** of capex for our AA5 network reinforcement program, summarised in Table 12.12.

**Table 12.12:** Network expansion capex in AA5 ($M real at 31 December 2019)

| CATEGORY | 2020 | 2021 | 2022 | 2023 | 2024 | TOTAL |
|---|---|---|---|---|---|---|
| **NETWORK GROWTH** | | | | | | |
| Mains extensions | - | - | - | - | 0.1 | 0.1 |
| Capacity upgrades | 0.3 | 0.1 | 0.2 | - | - | 0.6 |
| New regulating facilities | 0.6 | - | 0.3 | - | - | 1.0 |
| **TOTAL** | **1.0** | **0.1** | **0.5** | **-** | **0.1** | **1.7** |

## 12.9 Information technology (IT) ($36.1M)

BACKGROUND:

Information technology (IT) has become an integral part of our business, from large systems that monitor network reliability, to digital channels for our customers, to the smaller systems that enable employee communications such as email.

Our IT capex forecast balances our operational requirements, by upgrading and expanding existing IT systems, with our more strategic requirement to explore new opportunities for the digital transformation of our business. During AA5, our IT department will continue to deliver value for money by efficiently balancing capex and operational costs.

INVESTMENT DRIVERS:

IT capex is driven by the following:

- operational priorities based on our objectives for efficiency in alignment with business KPIs, customer feedback from the VoC program, improving the ease of doing business, and to achieve safe, reliable, and affordable natural gas services;
- specific mandated compliance timelines defined by the legislative and regulatory bodies; and
- the timing of vendor announcements of discontinuation of support for old technology; and the anticipated schedule of vendor releases for major upgrades and the complexity of the projects.

Table 12.13 summarises which aspects of NGR 79(2) each of the proposed IT programs meet.

**Table 12.13:** IT capex compliance with NGR 79(2) (primary justification in bold)

| NGR 79 | ENERGISED & RESPONSIVE CUSTOMER ENGAGEMENT | NETWORK DIGITISATION & INTELLIGENCE | ASSET MGT & SERVICE DELIVERY EXCELLENCE | ENTERPRISE &EMPLOYEE ENABLEMENT | APPLICATION RENEWAL |
|---|---|---|---|---|---|
| (2)(a) Economic value. | Yes | **Yes** | Yes | Yes | N/A |
| (2)(b) Incremental revenue vs present value of capex. | N/A | N/A | N/A | N/A | N/A |
| (2)(c)(i) Safety of services. | Yes | Yes | Yes | **Yes** | Yes |
| (2)(c)(ii) Integrity of services. | Yes | Yes | **Yes** | Yes | Yes |
| (2)(c)(iii) Regulatory obligation. | Yes | N/A | Yes | Yes | Yes |
| (2)(c)(iv) Meeting demand. | **Yes** | N/A | Yes | Yes | **Yes** |

PLANNED ACTIVITY:

We are planning the following IT capex projects for AA5:

- **Energised and responsive customer engagement ($2.9M)**

  This program enhances existing online services and introduces additional online services to enable efficient interactions with customers. This approach aligns with our VoC findings, by making it easier for all our customer segments to interact with us; providing multiple communication channels to enable different mediums for customers choice was important feedback.

The program provides enhanced features to our Commercial Customer Portal, enabling secure access to relevant customer and project information anywhere, anytime. This program will also extend the Commercial Customer Portal to other customer segments and provide residential customers with self-serve capabilities.

- **Network digitisation and intelligence ($1.3M)**

  This program implements IT/OT integration[62] technology; enabling the capture and integration of network condition data with our asset management processes. IT/OT integration allows more sophisticated analysis and management of our network, thereby improving network reliability. This program will also extend our metering and measurement capabilities to manage the increased data available from automated meter reading.

- **Asset management and service delivery excellence ($2.0M)**

  This program extends our technology solutions to improve both asset management (building on our Springboard Program in AA4) and greater automation in our operational processes. Specifically:

  - In AA5, we will extend the network asset management capability to fleet assets. Maintenance of our fleet is vital to enabling our work crews to provide services to our customers and to respond to incidents on our network.
  - The customer request processes will be streamlined through automated workflows and the automation of procurement and contract management processes. With the growth of the competitive retail market in Western Australia, larger volumes of customers switching retailers is driving the need to streamline the MIRN address verification process through additional automation.

- **Enterprise and employee enablement ($4.9M)**

  The success of our business is based on the ability of our employees to deliver services in an efficient, timely and safe manner that meets customer expectations. The Enterprise and Employee Enablement program will achieve this by extending our existing communication channels and workforce tools to improve information sharing and employee collaboration. The program includes:

  - Optimising how our team works and collaborates through enhancements in our secured internal and external communication channels.
  - Enhancing our performance management reporting and dashboard systems to support operational decision making.
  - Building on our existing document management foundation to provide a Knowledge Management System for employees to manage, share, and create relevant knowledge assets.

- **Application renewal ($24.9M)**

  This program ensures our business is operating on supported or up-to-date software applications and associated hardware. Failures or security breaches in any of these systems can result in prolonged outages, adversely affecting our customers.

  Based on software vendor lifecycle plans, we are planning upgrades to the Customer Care & Billing, Geographic Information System, Document Management, and Integration systems during AA5.

[62] IT/OT integration aims to reduce the typical separation of Information Technology (IT) and Operational Technology (OT) as areas with different authority and responsibility, by integrating processes and information flows.

FORECAST EXPENDITURE:

Table 12.14 outlines our proposed capex for IT in AA5.

**Table 12.14:** AA5 IT capex forecast ($M real at 31 December 2019)

| CATEGORY | 2020 | 2021 | 2022 | 2023 | 2024 | TOTAL |
|---|---|---|---|---|---|---|
| **IT Capex** | | | | | | |
| Energised and Responsive Customer Engagement | 1.2 | 1.0 | 0.4 | 0.3 | 0.1 | 2.9 |
| Network Digitisation and Intelligence | 0.2 | 0.2 | 0.4 | 0.4 | 0.2 | 1.3 |
| Asset Management and Service Delivery Excellence | 0.6 | 0.5 | 0.4 | 0.4 | 0.2 | 2.0 |
| Enterprise and Employee Enablement | 1.3 | 1.3 | 1.2 | 0.9 | 0.2 | 4.9 |
| Application Renewal | 4.2 | 5.9 | 4.0 | 3.5 | 7.4 | 24.9 |
| **TOTAL** | **7.4** | **8.8** | **6.4** | **5.5** | **8.0** | **36.1** |

## 12.10 Structures and equipment – Fleet ($16.4M)

BACKGROUND:

The fleet asset class comprises all motor vehicles, plant, and equipment assets that are licensed by the Western Australian Department of Transport. The asset class includes:

- Motorcycles
- Passenger vehicles
- Light commercial vehicles (e.g. utility vehicles and vans)
- Heavy vehicles
- Larger plant and equipment such trailers, mobile message boards, excavators, and compressors

We have a mobile workforce and locate our personnel and fleet close to operational demand centres to serve our customers more efficiently. The fleet underpins our operations and plays a vital role in enabling the work crews to undertake network maintenance activities, respond to network incidents promptly, connect new customers to the network, extend gas mains to support network growth, and provide a broad range of services to customers.

INVESTMENT DRIVERS:

Our fleet size and composition are driven by the workforce plan, which sets out the resources required to deliver the program of work as set out in the AMP. Where the workforce plan identifies a need for additional vehicles, we assess the existing fleet to determine whether the requirement can be met through redistribution of current assets, or if additional vehicles are required. Our forecast is developed for a 10-year horizon and includes the type and number of fleet assets.

Our fleet capex forecast is categorised into:

- **Fleet replacement**: Replacement of existing fleet assets due to asset condition and suitability.
- **Fleet demand**: New fleet assets required due to changes in business requirements.

These activities satisfy NGR 79 (2)(c)(ii); the capex is necessary to maintain and improve safety of services and maintain the integrity of services. These are achieved by ensuring our fleet remains fit for purpose, fully operational and in a good condition. Fleet assets are essential to respond to network incidents promptly and undertake network projects and maintenance activities effectively.

PLANNED ACTIVITY:

We forecast long-term **replacement of fleet assets** using age-based requirements, and then on an annual basis, we refine the annual replacement schedule based on:

- utilisation data (e.g. kilometres travelled, or engine hours metered);
- the vehicle's condition (e.g. through visual inspection and vehicle's maintenance history); and
- the vehicle's ongoing operational suitability.

We have developed our fleet replacement criteria in line with industry practice. The criteria are based on the recommended replacement timing for trucks (as published by the Institute of Public Works Engineering Australia in its Plant and Vehicle Management Manual), and the replacement criteria from other network operators. The fleet replacement criteria are documented in the ALS for fleet (see Attachment 12.7).

FORECAST EXPENDITURE:

Table 12.15 outlines our proposed total capex for fleet in AA5.

**Table 12.15:** Total fleet capex AA5 forecast ($M real at 31 December 2019)

| CATEGORY | 2020 | 2021 | 2022 | 2023 | 2024 | TOTAL |
|---|---|---|---|---|---|---|
| **Total Fleet** | 3.6 | 4.7 | 1.9 | 3.0 | 3.2 | **16.4** |

## 12.11 Structures and equipment – Facilities and plant and equipment ($6.4m)

BACKGROUND:

This asset class comprises all building, plant, and equipment assets either owned or leased by ATCO. Our Operations Centre is in Jandakot, with three depots in the Perth metropolitan area and three depots in the regional area (excluding Albany and Kalgoorlie).

Facilities underpin our operations and play a vital role in enabling the work crews to undertake network maintenance activities, respond to network incidents promptly, and provide reference services to customers.

The asset class also includes smaller plant and equipment assets such as tools that are used in the day-to-day operations.

INVESTMENT DRIVERS:

The size and location of our facilities are driven by the forecasted network activities (as set out in the AMP) related to the expanding footprint of our network.

These activities satisfy NGR 79 (2)(c)(ii); the capex is necessary to maintain and improve the safety of services and maintain the integrity of services. These are achieved by ensuring the tools and equipment used by our field staff to undertake their duties remain fit for purpose, fully operational and in a good condition.

PLANNED ACTIVITY:

No new facilities are planned for AA5. A portion of the new depot in Osborne Park will be carried over into AA5. We have identified several minor facility improvement initiatives for the seven facilities located in the Perth metropolitan and regional area, and these initiatives are spread across the five years.

FORECAST EXPENDITURE:

Table 12.16 outlines our proposed capex for Facilities and plant and equipment in AA5.

**Table 12.16:** Facilities and plant and equipment capex AA5 ($M real at 31 December 2019)

| CATEGORY | 2020 | 2021 | 2022 | 2023 | 2024 | TOTAL |
|---|---|---|---|---|---|---|
| Facility improvement | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | **0.5** |
| New Depot - Osborne Park (Building) | 0.7 | - | - | - | - | **0.7** |
| Facility Upgrade – PRS Security | - | 0.3 | 0.2 | - | - | **0.5** |
| Plant and equipment | 0.9 | 0.9 | 1.0 | 1.0 | 1.0 | **4.7** |
| **TOTAL** | **1.7** | **1.3** | **1.3** | **1.1** | **1.1** | **6.4** |

## 12.12 Overhead costs

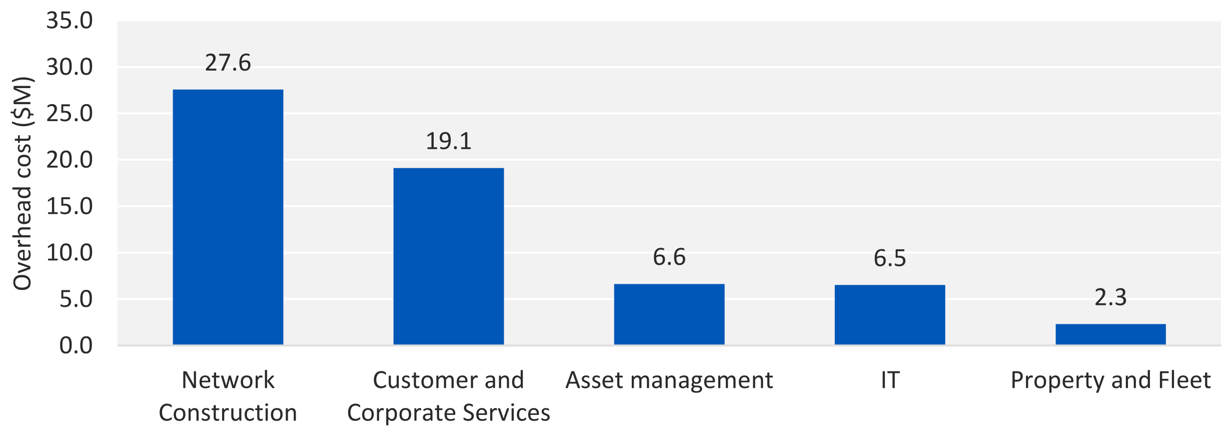
### 12.12.1 Overview

We define overheads as all the necessary *indirect* costs of delivering the capex program, except for the labour and materials costs that can be directly allocated. Overhead costs are not directly attributable to capex projects and activities via a source document such as a work order, invoice or a timesheet, but are incurred as a result of delivering the capex program.

We incur overheads as a result of supporting both the capex program and operations and maintenance activities. Overheads *relating to opex* are included as part of the total opex forecast in Chapter 11 and have not been separately analysed and reported. Only those overhead costs incurred as a result of supporting the capex program are reviewed and analysed in this section of our 2020-24 Plan.

We are forecasting to capitalise overhead costs of $62.1 million in AA5. Figure 12.3 shows the breakdown of overheads across the various cost categories. These overhead costs are justifiable under NGR 79(2) on the same basis as the underlying capex.

**Figure 12.3:** AA5 overhead ($M real at 31 December 2019)



Overheads relating to the forecast capex include the indirect costs associated with network construction, customer and corporate services, IT, asset management and property and fleet management:

**Network construction**: Includes indirect costs associated with the establishment and maintenance of pipeline assets including the internal labour cost (and associated fleet, IT and telecommunications costs) of management and administration support. It also includes the costs of training staff, planning teams and inspection teams whose hours cannot be directly attributed to projects and activities but are indirectly driven by network construction.

**Customer and corporate services:** Relate to the portion of services provided by corporate departments such as Finance, Human Resources, Regulatory, Legal and Risk that relate to the capex program but cannot be directly allocated to projects or activities via timesheets or invoices. Most of these costs are internal labour and the associated costs of employee's fleet, IT and telecommunications.

**Asset management:** Includes the indirect costs of technical support services, compliance and risk departments, and asset services. Most of these costs are internal labour and associated costs of staff whose hours cannot be allocated directly to projects and activities but arise as a consequence of incurring directly attributable costs.

**IT:** Relates to a portion of total technology costs that are indirectly associated with the construction of our network assets. These costs include a portion of software licences, storage and connectivity services and are incurred to establish the capital assets but cannot be directly attributed to individual projects and activities.

**Property and fleet:** Relates to fleet management, office services, and a portion of costs associated with running premises that support the capex program.  Most of these costs relate to property expenses and the cost of the support staff whose hours indirectly benefit the capex program.

### 12.12.2 Approach

We have adopted the base-step-trend (BST) method to calculate overheads to be capitalised. Given that the nature of overhead costs is largely fixed, the BST method is suitable. For consistency, we have used the step changes and trends assumed for forecast opex (see Chapter 11) for the forecast overhead calculation.

Using the BST approach means using overhead costs in the efficient base year to forecast overheads for AA5. By using 2017 costs to predict future overheads, ATCO ensures that a prudent approach is applied to the overhead estimate for AA5 and achieves the lowest sustainable overhead cost to support the capex program.

### 12.12.3 Establish the efficient base year for overheads

We have used our actual overheads from the most recent complete calendar year (2017) as representative overhead costs for AA5. We have assumed that any efficiency savings made in 2017 are recurrent and will continue to apply in the future. We have established our base overhead costs for AA5 by calculating the level of outperformance in 2017 compared to our 2017 AA4 forecast and then applying that level of outperformance to the AA4 2019 overhead forecast. This approach ensures that the base overhead forecast includes the expected movement in costs over the remainder of AA4. We have then adjusted the base overhead costs to remove any 2019 non-recurrent expenditure. The use of a base level of overhead, based on our actual overhead, reflects that overheads are recurrent in nature.

### 12.12.4 Adjusting overheads for step changes in recurrent expenditure

The activities during AA5 that are not reflected in our base year are known as 'step changes'. Step changes include the additional costs of associated safety, compliance, and regulatory activities that are typically driven by a change in obligation. The step changes we have identified for AA5 and the justification for each of these step changes is outlined in Section 11.6.2.1.

We have analysed the cost detail of each step change and identified the direct and indirect components (overheads). We firstly identify the department that will drive these step costs and estimate their respective portion of the step cost. Each of these departments has a typical overhead percentage based on established business rules; these overhead percentages are used to calculate the total overhead associated with the step costs.

As an example, the step cost relating to Supervisory Control and Enhanced Data Acquisition includes labour costs to deliver the project. Although a portion of labour costs are time-written and capitalised to the project directly, the portion relating to administration, support and management costs associated with this project have been determined as indirect capex. The overhead component of each step change is outlined in Table 12.17.

**Table 12.17:** Adjustments for the overhead component of recurrent step changes ($M real as at 31 December 2019)

| RECURRENT STEP CHANGES | AA5 TOTAL |
|---|---|
| Supervisory Control and Enhanced Data Acquisition | $1.1 |
| Additional leak survey and repair | $0.3 |
| **Total recurrent step changes** | **$1.4** |

### 12.12.5 Adjusting overheads for non-recurrent expenditure

Several non-recurrent costs will occur during AA5 that are not reflected in our base year. The non-recurrent step changes we have identified for AA5 are detailed in Table 11.5. The justification for each of the non-recurrent costs is outlined in Section 11.6.2.2.

As with the recurrent step changes, the overhead component has been calculated based on the proportion of costs that will not be directly attributable to the step change activity (i.e. the proportion of the costs that cannot be traced to the activity via invoice, timesheet or other source document but arises as a consequence of these activities). The overheads that relate to capex are outlined in Table 12.18.

**Table 12.18:** Adjustments for the overhead component of non-recurrent step changes ($M real as at 31 December 2019)

| NON-RECURRENT EXPENDITURE | YEAR | AA5 TOTAL |
|---|---|---|
| Mains reclassification in private properties | 2020, 2021 & 2022 | $0.1 |
| Access Arrangement Six regulatory preparation | 2023 & 2024 | $0.3 |
| **Total non-recurrent step changes** | | **$0.4** |

### 12.12.6 Trend to account for forecast growth

We incur additional expenditure as the number of customers connected to the network increases and as the size of the network increases; most of this additional expenditure is *directly allocated* to capex. *Indirect* *costs* (overheads) also increase with additional customer connections and network growth. These increases in overheads include, for example, more support services.

It is therefore appropriate that we escalate our base year overhead by forecast growth in customer numbers and the increased size of our distribution network (measured in km of mains). The overhead associated with forecast growth is $2.7 million in AA5 and is calculated by applying a cumulative growth factor to the overhead value in the "efficient base year".

### 12.12.7 Trend to account for forecast price growth

Forecast price growth typically accounts for price increases in labour and non-labour (e.g. materials). Our forecast price growth results in an additional $1.8 million of overhead in AA5.

Our approach to escalating input costs is based on the following:

- A resource mix of 62% labour and 38% non-labour costs based on benchmark weights developed by the Pacific Economics Group[63]. The resource mix adopted is conservative compared to the actual overhead resource mix but has been applied to maintain consistency with the opex BST assumptions.
- Labour cost escalation over AA5 is based on the forecast annual rate of growth in the wage price index determined by an independent expert.
- We have forecast that non-labour costs do not incur any additional price rises over and above inflation.

### 12.12.8 Productivity growth

As with base opex, we have not applied a productivity adjustment on the basis that our benchmark performance is already considered efficient compared to our peers (see Section 11.6.1).

### 12.12.9 Overhead forecast

We forecast $62.1 million of overhead costs to be capitalised in AA5. Table 12.19 outlines the details of these costs.

**Table 12.19:** Capitalised portion of overhead expenditure ($M real as at 31 December 2019)

| | 2020 | 2021 | 2022 | 2023 | 2024 | TOTAL |
|---|---|---|---|---|---|---|
| **Base Year** | 11.2 | 11.2 | 11.2 | 11.2 | 11.2 | **55.9** |
| **Recurrent Step Changes** | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 | **1.4** |
| **Non-Recurrent Step changes** | 0.0 | 0.0 | 0.0 | 0.2 | 0.2 | **0.4** |
| **Network and customer growth** | 0.2 | 0.4 | 0.5 | 0.7 | 0.9 | **2.7** |
| **Price escalation** | 0.1 | 0.2 | 0.4 | 0.5 | 0.6 | **1.8** |
| **TOTAL** | **11.7** | **12.0** | **12.4** | **12.9** | **13.2** | **62.1** |

These overhead costs are included in our AA5 capex forecast as detailed in Table 12.3.

63 Pacific Economics Group, TFP Research for Victoria's Power Distribution Industry, December 2004. http://www.esc.vic.gov.au/wp-content/uploads/archives/9175/3267_PEG_TFP_Report.pdf

# 13. Capital base

**CHAPTER HIGHLIGHTS**

1. The capital base has been rolled forward over AA4 using forecast depreciation and actual capex.
2. Our opening capital base has increased from $1,104 million at 30 June 2014 to $1,348 million as at 1 January 2020.
3. Our projected capital base at the end of AA5 is $1,563 million.

## 13.1 Introduction

The forecast value of our capital base at 1 January 2020 is $1,347.5 million. The value of our capital base is a primary input into our total revenue calculation; it forms the basis of our *return on assets*, and *depreciation* building blocks.

As part of the access arrangement process, we are required to adjust our capital base in relation to capex, depreciation and inflation using actual information from AA4, and forecast information from AA5. This chapter discusses how we have made those adjustments for AA4 and AA5, and sets out:

- How the capital base from AA4 has been rolled forward to determine the opening capital base at 1 January 2020, and by how much.
- How the projected capital base for AA5 has been calculated and its projected value.

The chapter will focus on the method used to calculate the capital base; including the treatment of inflation, disposals, capital contributions, and depreciation. Capex is detailed in Chapter 12 and will only be mentioned in this chapter to the extent it affects the value of the capital base.

## 13.2 Regulatory framework

The main governing rules in the NGR for calculating our capital base are:

- **Rule 77**: Opening capital base calculation. Rule 77 determines the approach for the calculation of the opening capital base at 1 January 2020 (start of AA5). Calculation of the opening capital base is set out in Section 13.4.
- **Rule 78**: Projected capital base calculation. Rule 78 determines the approach for the projected capital base calculation; the projected capital base being the capital base over AA5. Calculation of the projected capital base is set out in Section 13.5.

Other rules to be considered regarding the capital base are:

- Rule 82: Capital contributions by users to new capital expenditure
- Rule 84: Speculative capital expenditure account
- Rule 85: Capital redundancy
- Rule 86: Re-use of redundant assets
- Rule 88: Depreciation schedule
- Rule 89: Depreciation criteria
- Rule 90: Calculation of depreciation for rolling forward the capital base from one access arrangement period to the next

Information pertinent to these rules is covered in Section 13.6.

## 13.3 Stakeholder engagement

ATCO published a Draft Plan at the beginning of May 2018 inviting feedback from stakeholders. Several retailers and other parties provided feedback. The feedback relevant to the capital base is summarised in Table 13.1.

**Table 13.1:** Stakeholder feedback: capital base

| DRAFT PLAN QUESTION | STAKEHOLDER FEEDBACK | OUR RESPONSE TO FEEDBACK ON THE DRAFT PLAN |
|---|---|---|
| Do you consider our calculation of the opening and projected capital base to be fair and reasonable? | There were no specific comments regarding calculation of the opening and projected capital base other than to say it was a matter for the ERA. | **No change** to our Draft Plan |
| Do you agree with the separation of the new telemetry asset class from other IT expenditure? | There was general support for the creation of a separate telemetry asset class. | **No change** – separate telemetry class is proposed for AA5. |

The stakeholder feedback does not require any change to the capital base calculation method proposed in the Draft Plan.

## 13.4 Opening capital base

The opening capital base is calculated using the 'roll forward' method, as set out in Rule 77(2) of the NGR. Depreciation used to calculate the roll forward asset base is the forecast depreciation in the ERA's AA4 Final Decision.

**Figure 13.1:** Opening capital base calculation


The opening capital base for AA5 (1 January 2020) is calculated to be $1,347.5 million as shown in Table 13.2.

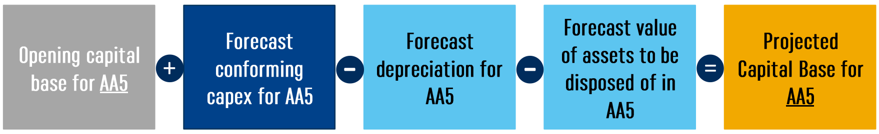
**Table 13.2:** Opening capital base for AA5 ($M real as at 31 December 2019)

| | JUL TO DEC 2014 | 2015 | 2016 | 2017 | 2018 (F) | 2019 (F) |
|---|---|---|---|---|---|---|
| Opening Capital Base | 1,103.8 | 1,129.6 | 1,170.6 | 1,219.0 | 1,263.9 | 1,312.1 |
| Capex (net) (see Chapter 12) | 43.9 | 80.9 | 92.9 | 92.4 | 98.3 | 88.6 |
| Depreciation | -18.1 | -39.9 | -44.3 | -47.3 | -50.1 | -53.2 |
| Asset Disposals | -0.0 | -0.0 | -0.2 | -0.2 | - | - |
| **Closing Capital Base** | **1,129.6** | **1,170.6** | **1,219.0** | **1,263.9** | **1,312.1** | **1,347.5** |

## 13.5 Projected capital base

The projected capital base is calculated using the roll forward method, as set out in Rule 78 of the NGR.

**Figure 13.2:** Projected capital base calculation




The projected capital base over AA5 is provided in Table 13.3, considering forecast (straight-line) depreciation and capex. The table shows a projected capital base of $1562.5 million as at 31 December 2024.

**Table 13.3:** Projected capital base ($M real as at 31 December 2019)

| | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|
| Opening Capital Base | 1,347.5 | 1,402.4 | 1,446.2 | 1,486.1 | 1,526.0 |
| Capex (net) (see Chapter 12) | 103.4 | 102.2 | 100.4 | 102.2 | 101.3 |
| Depreciation (as per Section 13.6.2) | -48.5 | -58.4 | -60.5 | -62.2 | -64.7 |
| Asset Disposals | - | - | - | - | - |
| **Closing Capital Base** | **1,402.4** | **1,446.2** | **1,486.1** | **1,526.0** | **1,562.5** |

## 13.6 Supporting Information and assumptions

### 13.6.1 Capital contributions (Rule 82)

Capital contributions received have been netted off against conforming capex so that only the net amount is included in the capital base and the tax asset base.

We recover the tax costs that we incur when we receive a capital contribution from the customer paying the capital contribution. The amount of the capital contribution netted off against conforming capex does not include this additional tax cost recovery. We determine the tax cost to be the net present value effect of the timing difference between the capital contribution being assessed as *taxable income* and the related depreciation being assessed as a *tax expense*.

### 13.6.2 Depreciation (Rules 88, 89 and 90)

The depreciation schedule (*Rules 88 and 89*) for establishing the opening capital base and projected capital base, is based on the asset classes and the forecast depreciation in the ERA's AA4 Final Decision tariff model. All assets are depreciated using the straight-line method (i.e. a current cost accounting approach) consistent with the ERA's AA4 Final Decision tariff model.

The depreciation schedule provides for the depreciation of each group of assets over their economic life. An asset is depreciated only once, so that the depreciation amount over its economic life does not exceed the value of the asset at the time of its inclusion in the asset base. Regulatory precedent suggests that the current cost accounting method is an appropriate depreciation method such that reference tariffs will vary over time in a way that promotes efficient growth in the market for reference services.

For the projected capital base, following a review of our asset classes, a new asset class for 'Telemetry' has been created with an economic life of ten years. We created this new asset class due to the increased need in our business for remote monitoring of our assets (*see Section 12.7.4)*.

The economic lives for asset categories are shown in Table 13.4. The asset life of 'equity raising costs' for AA5 has been amended to align with the average life of assets at 31 December 2019, rather than 30 June 2014.

**Table 13.4:** Economic lives of asset categories (years)

| ASSET CATEGORIES | ECONOMIC LIVES | |
|---|---|---|
| | AA4 | AA5 |
| **CURRENT AND NEW ASSET CATEGORIES** | | |
| HP mains – steel | 80.0 | 80.0 |
| HP mains – PE | 60.0 | 60.0 |
| Medium and low pressure mains | 60.0 | 60.0 |
| Regulators | 40.0 | 40.0 |
| Secondary gate stations | 40.0 | 40.0 |
| Buildings | 40.0 | 40.0 |
| Meter and services pipes | 25.0 | 25.0 |
| Plant and equipment | 10.0 | 10.0 |
| Vehicles | 10.0 | 10.0 |
| Information technology | 5.0 | 5.0 |
| Land | - | - |
| Equity raising cost | 65.8 | 53.1 |
| Telemetry | N/A[64] | 10 |
| **HISTORICAL ASSET CATEGORIES – NO LONGER USED FOR NEW CAPEX** | | |
| Medium pressure mains | 60.0 | 60.0 |
| Low pressure mains | 60.0 | 60.0 |
| Full retail contestability (historical IT costs) | 5.0 | 5.0 |

The asset lives for assets included in the initial capital base at 1 January 2000 remain unchanged and are as stated in the ERA's AA4 Final Decision tariff model.

*Rule 90* requires that an access arrangement must contain a provision governing the calculation of depreciation in the following access arrangement period (i.e. AA6) and resolving whether such depreciation is to be based on actual or forecast depreciation.

We propose that the opening capital base in AA6 will be calculated using AA5 forecast depreciation. We have adopted the same approach to forecast depreciation as we used in AA4. Using forecast rather than actual depreciation supports efficient capex decisions[65]. Forecast depreciation by asset class over AA5 is shown in Table 13.5.

64 Prior to AA5, telemetry was included in the Information Technology category

65 Economic Insights Pty Ltd. *The use of actual or forecast depreciation in energy network regulation, report prepared for Australian Energy Market Commission*, 31 May 2012

**Table 13.5:** Forecast depreciation AA5 ($M real as at 31 December 2019)

| ASSET CATEGORIES | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|
| High pressure mains - steel | 3.5 | 3.7 | 3.8 | 3.9 | 4.1 |
| High pressure mains - PE | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Medium pressure mains | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 |
| Medium and low pressure mains | 10.2 | 10.8 | 11.3 | 11.9 | 12.5 |
| Low pressure mains | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 |
| Regulators | 1.2 | 1.2 | 1.3 | 1.3 | 1.3 |
| Secondary gate stations | 0.2 | 0.5 | 0.7 | 0.8 | 0.7 |
| Buildings | - | 0.9 | 0.9 | 0.9 | 0.9 |
| Meter and services pipes | 20.9 | 22.3 | 23.6 | 25.0 | 26.5 |
| Equipment and vehicles | 2.0 | 2.0 | 2.0 | 1.8 | 1.3 |
| Vehicles | -0.1[66] | 1.4 | 1.8 | 2.0 | 2.3 |
| Information technology | 3.2 | 7.8 | 6.8 | 6.0 | 6.2 |
| Telemetry and monitoring | - | 0.3 | 0.7 | 1.0 | 1.3 |
| Full retail contestability | - | - | - | - | - |
| Land | - | - | - | - | - |
| Equity raising costs | - | - | - | - | - |
| **TOTAL DEPRECIATION** | **48.5** | **58.4** | **60.5** | **62.2** | **64.7** |

### 13.6.3 Rules 84, 85, 86

No events have occurred in AA4 or are forecast to occur during AA5 that would require adjustment to the capital base under Rules 84, 85, or 86.

### 13.6.4 Inflation

We have applied an inflation adjustment to the opening capital base, consistent with the method applied in the ERA's AA4 Final Decision tariff model. The inflation percentages applied to the opening capital base in each period are shown in Table 13.6.

**Table 13.6:** Inflation on opening capital base

| JUL-DEC 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|---|---|---|---|
| 0.66% | 1.69% | 1.48% | 1.91% | 1.84% | 1.84% | 1.84% | 1.84% | 1.84% | 1.84% | 1.84% |

Assumptions:

- Inflation from **July 2014 to December 2017** is actual inflation; the weighted average of eight capital cities as published by the Australian Bureau of Statistics.
- Inflation for **2018 to 2024** is our forecast based on the yield differential between 5-year indexed and non-indexed Commonwealth Government bonds. This method is often referred to as the 'Bond breakeven without adjustment' method. It is important that this market-based approach is used to forecast inflation over AA5 because it is based on the same data that is used to estimate the nominal risk-free rate used to calculate the nominal cost of debt and equity. Therefore, the inflation estimate used in our capital base calculations is consistent with inflation assumptions used in rate of return calculations.

66 Due to clawback of over-depreciation of $0.9 million relating to 2015 capex

### 13.6.5 Capex

Our application of the roll forward method adopts an end-of-year timing assumption for capex, consistent with inflation and net present value cashflow assumptions. Capex is included in the asset base on an '*as incurred*' basis rather than a *commissioned* basis because the expenditure must be funded as it is incurred. Regarding the revenue building blocks, capex starts to depreciate from 1 January in the year following the year of acquisition.

### 13.6.6 Disposals

We have deducted actual asset disposals from the capital base on the following basis:

- To the end of 2016, we valued disposals at the lower of written down value or sale proceeds.
- After 2016, we valued disposals based on sale proceeds.

The reason for the change is due to disposals becoming more substantial from 2017; primarily due to the disposal of vehicle assets. We have therefore reviewed our policy and examined the practices of other regulated businesses regarding asset disposals. Following that review, we determined that disposals should be valued at sale proceeds and the proceeds offset against capex in the year of disposal.

While we haven't forecast any disposals for AA5, if there *are* asset disposals during AA5, these will be deducted from the opening capital base at the start of AA6.

### 13.6.7 Unregulated and non-reference assets

Capex has been allocated to reference services in accordance with our Cost Allocation Method. Capex allocated to the provision of unregulated services (i.e. expenditure not related to the covered pipeline), has been excluded from the capital base. In addition, any capex allocated to the provision of non-reference services has also been excluded from the capital base. This ensures that the capital base only incorporates the costs related to providing reference services.

# 14. Rate of return

**CHAPTER HIGHLIGHTS**

1. Our estimate of the rate of return is 6.03% (vanilla nominal after-tax), which is based on the draft Rate of Return Guidelines published by the ERA on 29 June 2018 (with some exceptions) and market data to the end of 29 March 2018.
2. We expect the ERA to issue the binding Rate of Return Guidelines in December 2018, and we expect these binding guidelines will apply to the ERA's Draft and Final Decisions.

## 14.1 Introduction

We expect to adopt the ERA's updated Rate of Return Guidelines to determine the rate of return for AA5 once it is finalised later in 2018. The updated guidelines are expected to be binding on both ATCO and the ERA. We anticipate that the necessary legislative changes to implement the binding Rate of Return Guidelines will be gazetted by December 2018.

The ERA published its draft Rate of Return Guidelines on 29 June 2018 and is seeking submissions from stakeholders by 28 September 2018. We expect the ERA will issue the final guidelines once the necessary legislative changes to implement the binding Rate of Return Guidelines have been gazetted. We understand that this is expected to occur ahead of the ERA's Draft Decision.

In making the binding Rate of Return Guidelines, the ERA will be required to satisfy itself that the Guideline will, or is most likely to, contribute to the achievement of the NGO to the greatest degree.[67] To achieve this, we believe that each parameter should be estimated using best available empirical estimates, as discussed below.

We have prepared our estimate of the rate of return based on the methods and values detailed in the draft Rate of Return Guidelines (with some exceptions) and market data to the end of 29 March 2018. Our position on the draft Guidelines is summarised in Table 14.1.

**Table 14.1:** Summary of ATCO's position

| PARAMETER | ACCEPTED BY ATCO | SUMMARY OF ATCO'S POSITION |
|---|---|---|
| **The benchmark efficient entity** | ✓ | ATCO accepts the draft Guidelines |
| **Gearing** | ✓ | ATCO accepts the draft Guidelines |
| **Inflation** | ✓ | ATCO accepts the draft Guidelines |
| **RETURN ON DEBT** | | |
| Risk free rate of return | ✓ | ATCO accepts the draft Guidelines |
| Benchmark credit rating | ✓ | ATCO accepts the draft Guidelines |
| Debt risk premium | ✓ | ATCO accepts the draft Guidelines but notes that the Guidelines needs to be modified to include sufficient detail to allow for a mechanical calculation |

[67] Proposed new section 30D of the National Gas Law, as set out in the *Statutes Amendment (National Energy Laws)(Binding Rate of Return Instrument) Bill 2018*, as introduced into the South Australian Parliament on 2 August 2018

| PARAMETER | ACCEPTED BY ATCO | SUMMARY OF ATCO'S POSITION |
|---|---|---|
| Debt and equity raising costs | ✓ | ATCO accepts the draft Guidelines |
| **RETURN ON EQUITY** | | |
| Risk free rate of return | ✓ | ATCO accepts the draft Guidelines |
| Market risk premium | - | ATCO details its preferred method to determine the market risk premium in Section 14.4.3 |
| Equity beta | ✓ | ATCO accepts the draft Guidelines |
| **Gamma** | - | ATCO details its preferred method to determine gamma in Section 15.3 |

As summarised in Table 14.1, we believe that there is a strong argument to modify the proposed approach in the Guidelines regarding the market risk premium (**MRP**) and gamma to ensure the best estimate is used and the binding Guidelines will, or is most likely to, contribute to the NGO[68]. In summary, our position on these parameters is:

- **Market risk premium:** We submit that the MRP should be determined mechanically by applying equal weight to the dividend growth model (**DGM**) and arithmetic mean of the historical MRP to derive the point estimate of the MRP. We submit that this approach:
  - Considers all relevant data, both historical and forward-looking. Both the current Rules and the proposed legislative amendments include these criteria.
  - Considers prevailing conditions in the market for equity funds. Both the current Rules and the proposed legislative amendments include these criteria.
  - Gives rise to the best possible empirical estimate of the MRP, ensuring the resulting rate of return contributes to the NGO to the greatest degree, as required both by the current Rules and under the proposed legislative amendments.
- **Gamma:** We support the adoption of ATO's tax statistics as the best, and most direct, estimate of an upper-bound for a 'utilisation' gamma. The resultant value for the Guidelines is 0.34. As with MRP, we consider this approach gives rise to the best estimate of gamma and will contribute to the NGO to the greatest degree.

We note that each of the parameters to the rate of return may be subject to change as the Rate of Return Guidelines process is ongoing, and we reserve the right to update any of these parameters as a result of that separate process.

## 14.2 Stakeholder engagement

We sought feedback from stakeholders on whether the proposed rate of return was reasonable. Feedback on our Draft Plan (published in May 2018) indicated that stakeholders supported our adopted method to determine the cost of debt, including the 10-year debt risk premium, and that stakeholders expected we would follow the ERA's Rate of Return Guidelines when they are finalised later in 2018. Table 14.2 summarises our response to the feedback.

[68] This is a requirement under the current Rules, as well as under the proposed binding Guidelines legislative changes.

**Table 14.2:** Consideration of stakeholder feedback on the rate of return

| DRAFT PLAN STAKEHOLDER QUESTION | STAKEHOLDER FEEDBACK | OUR RESPONSE TO FEEDBACK ON OUR DRAFT PLAN |
|---|---|---|
| Do you consider that 5.96% as our proposed rate of return is reasonable? | Retailer B submitted that it is important to consider the effect on end-use customers of regulated assets when determining the rate of return to apply during an access arrangement period. Retailers require price certainty to minimise financial risks when entering into energy contracts with customers. End-use customers also benefit from price certainty. | **Change** - ATCO has considered the effect of its submission on end-use customers holistically, including whether our approach to pricing provides both retailers and consumers with price certainty, as well as considering the rate of return framework and proposed legislative changes more broadly. As a result, we have modified several of the rate of return parameters; including reducing the MRP from 7.4% to 6.9%. |
| | Retailer B expressed concern that greater volatility in the debt risk premium will flow through to end-use customers via higher and potentially more volatile prices. The only way to manage this risk is by passing it on to customers via higher overall energy prices. As such, Retailer B supports the proposed 10-year period for debt risk premium which gives greater certainty to both network investors and gas consumers. | **No change** – We will adopt a 10-year term for the debt risk premium. This, in conjunction with the hybrid trailing average adopted by ATCO in AA4 and proposed for AA5, reduces the volatility in the cost of debt over time compared to the 'on the day' approach adopted in AA3. |
| | Retailer B expressed support for the adoption of the method used by the ERA for the 2016-2020 Dampier to Bunbury Natural Gas Pipeline (DBNGP) access arrangement, updated to reflect available market data as at November 2017. We anticipate ATCO following the ERA's Rate of Return Guidelines when they are published later this year. | **Change** – As noted above, we have updated the market data to incorporate data from March 2018 into the estimate of the rate of return. We will confidentially nominate a period for the ERA to sample the market-driven parameters. |
| | **Retailer A** submitted that at first glance, the Rate of Return estimate proposed by ATCO seems reasonable given the current ERA method (and comparing with the current AER Guidelines). Retailer A recognises that both the ERA (and the AER) are reviewing the method used for determining the rate of return and therefore withholds any detailed comment. | **No change** – Our rate of return estimate is based on the methods used to determine the rate of return for the Dampier to Bunbury Natural Gas Pipeline access arrangement in June 2016 and the Western Power Draft Decision in May 2018. We expect the ERA to issue updated guidelines shortly that will apply to the review of this access arrangement. |

| DRAFT PLAN STAKEHOLDER QUESTION | STAKEHOLDER FEEDBACK | OUR RESPONSE TO FEEDBACK ON OUR DRAFT PLAN |
|---|---|---|
| | **Retailer A** noted that the proposed Return on Equity for the next Access Arrangement period would be higher than that used over the last two regulatory periods. This is obviously a function of the formula and parameters used but given the change in economic conditions throughout these periods is, at face value, worrisome. **Retailer A** would like to see further explanation and justification of this estimate in the final proposal. | **Change** – We have reconsidered our estimate of the cost of equity and reduced the MRP from 7.4% to 6.9%. |

## 14.3 Proposed rate of return

We have adopted a vanilla nominal after-tax formulation of the rate of return, consistent with the draft Rate of Return Guidelines. The vanilla nominal after-tax rate of return formulation is as follows:

$$WACC_{Nom} = r_e \times E/(E+D) + r_d \times D/(E+D)$$

where:

$r_e$ is the cost of equity

$r_d$ is the cost of debt

$E$ is the proportion of equity used to finance regulated assets by a benchmark efficient entity

$D$ is the proportion of debt used to finance regulated assets by a benchmark efficient entity

$E+D$ equals 1.

Table 14.3 details the parameters adopted to estimate the rate of return to determine the building block revenue requirement.

**Table 14.3:** Rate of return estimate

| WACC COMPONENT | AA4 RATE OF RETURN (2018 DRP[69] values) | 2020 PROPOSED RATE OF RETURN |
|---|---|---|
| Nominal risk-free rate | *1.96%* | 2.37% |
| Real risk-free rate | *0.06%* | 0.52% |
| Inflation rate | *1.90%* | 1.84% |
| Debt proportion | *60%* | 55% |
| Debt Risk Premium (**DRP**) (10-year average) | *2.605%* | 2.267% |
| 5-year interest rate swap (effective yield) | *2.430%* | 2.590% |

69 Based on 2018 Debt Risk Premium (DRP) values

| WACC COMPONENT | AA4 RATE OF RETURN (2018 DRP[69] values) | 2020 PROPOSED RATE OF RETURN |
|---|---|---|
| 5-year interest rate swap spread | *0.47%* | 0.22% |
| Debt issuing cost (0.100%) + hedging (0.114%) | *0.24%* | 0.214% |
| **Return on debt** | ***5.275%*** | **5.07%** |
| Market Risk Premium (MRP) | *7.50%* | 6.90% |
| Equity beta | *0.7* | 0.7 |
| Corporate tax rate | *30%* | 30% |
| Franking credit | *0.25* | 0.34 |
| **Nominal after-tax return on equity** | ***7.21%*** | **7.20%** |
| **Nominal after-tax WACC[70]** | ***6.05%*** | **6.03%** |
| Real after-tax WACC | *4.07%* | 4.11% |

We have based our proposed rate of return on the *return on debt* estimate for 2020. We have adopted the 2020 rate of return in our modelling of the building block revenue requirement over AA5 and to set the resulting price path. However, an update to the rate of return will be incorporated into each of the Annual Tariff Variations over AA5, as described in Section 14.5.3 below.

## 14.4 Return on equity

We have estimated the return on equity by adopting the Sharpe-Lintner capital asset pricing model (SL CAPM), consistent with the draft Rate of Return Guidelines.

The SL CAPM uses the following formula:

$$r_e = r_f + \beta \times MRP$$

where:

$r_e$ is the cost of equity

$r_f$ is the risk-free rate for equity

$\beta$ is the equity beta of a benchmark efficient entity

$MRP$ is the market risk premium.

### 14.4.1 Risk-free rate (cost of equity)

The risk-free rate is calculated from the annualised yields on 5-year Commonwealth Government Securities as the proxy for the risk-free rate.

For this submission, we have calculated the risk-free rate over the 20 trading days to 29 March 2018 as a placeholder. We will separately and confidentially notify the ERA of the average period we intend to adopt for AA5.

70 Weighted Average Cost of Capital

### 14.4.2 Equity beta

We have adopted an equity beta of 0.7 consistent with the draft Rate of Return Guidelines. The ERA's draft Guidelines have estimated the equity beta from a proxy group of comparable Australian companies that derive a significant portion of their revenue from regulated energy infrastructure.

### 14.4.3 Market risk premium

We propose an estimate of the MRP based on our preferred method.

In developing this proposal, we have had regard to the draft Guidelines, the existing requirements under the NGR, as well as the proposed changes to the NGL to give effect to the binding Rate of Return Guidelines.[71] The common requirements of both the current rate of return framework (NGR Rule 87 and section 28 of the NGL) and the proposed legislative amendments are to:

1. Ensure the rate of return (and the binding Guidelines) will, or is most likely to, contribute to the achievement of the NGO to the greatest degree.[72]
2. Have regard to[73]:
    a) The revenue and pricing principles.
    b) Estimation methods, financial models, market data and other evidence relevant to making the instrument.
    c) Prevailing conditions in the market for equity funds.
    d) Interrelationships between financial parameters.

The MRP compensates an investor for the systematic risk of investing in a fully diversified portfolio. The MRP cannot be directly observed as it needs to be estimated for a future period. In response to the draft Rate of Return Guidelines, our view is that the MRP is best estimated by:

1. Deriving an estimate of the historical MRP from the arithmetic average of the historical excess returns.
2. Deriving an estimate of the forward-looking MRP from DGM estimates.
3. Determining mechanistically, the point estimate for the MRP as the mid-point between the historical MRP estimate and the forward-looking MRP estimate.

The following sections discuss each of these points in turn.

[71] As set out in the *Statutes Amendment (National Energy Laws)(Binding Rate of Return Instrument) Bill 2018,* as introduced into the South Australian Parliament on 2 August 2018.

[72] *Statutes Amendment (National Energy Laws)(Binding Rate of Return Instrument) Bill 2018,* proposed new section 30D(3).

[73] *Statutes Amendment (National Energy Laws)(Binding Rate of Return Instrument) Bill 2018,* as introduced into the South Australian Parliament on 2 August 2018, proposed new section 30A, definition of explanatory information that requires the regulator to explain how it has regard to these factors. See also proposed new 30D(5).

### Determining the historical market risk premium

The draft Guidelines recognise that the historical approach is not a forward-looking estimate of the MRP but contributes to investors' forward expectation.[74] We accept that the historical market risk premium is one piece of relevant evidence that should receive material weight, but not *determinative* weight above all other evidence. This is illustrated by the following comment attributed to Stephen Gray as part of the recent expert evidence sessions:

> *"The reason for this is best illustrated in the context of the GFC - the HER approach suggested that the cost of equity capital fell dramatically during the peak of the GFC. Clearly, such an approach should not be the determinative method for setting the allowed return on equity"*[75]

The draft Guidelines have adopted both the arithmetic and geometric means to derive the historical estimate of the MRP.[76]

Dr Lally has considered whether an arithmetic or geometric mean should be applied to the historical data. He evaluates whether each form of average is consistent with the NPV=0 principle and concludes that:

> *The geometric mean fails this test whilst the arithmetic mean will satisfy it if annual returns are independent and drawn from the same distribution. So, if historical average returns are used, they should be arithmetic rather than geometric.*[77]

Dr Lally has also derived a mathematical proof that confirms the arithmetic mean should be applied.[78]

We submit that the draft Guidelines incorrectly adopt the geometric mean, and our proposed MRP estimate instead incorporates an estimate of the historical MRP based on the arithmetic mean only. The adoption of the arithmetic mean is consistent with the application of the 'present value principle' in other aspects of the Guidelines and gives rise to the best empirical estimate of the historical MRP.

### Determining the forward-looking estimate

We are concerned that the draft Guidelines have down-weighted the DGM. This is a material change to the estimation of the MRP and seriously undermines regulatory stability and certainty. In placing less reliance on the DGM, we are of the view that service providers will no longer be provided with a reasonable opportunity to recover at least the efficient costs the service provider incurs in providing reference services. This is inconsistent with the revenue and pricing principles that the ERA must have regard to in deriving the rate of return.

The ERA is also required by both the current Rate of Return Rules and the proposed amendments to the NGL discussed above to have regard to:

1. All relevant estimation methods, which in our view must include the DGM estimates.
2. Prevailing conditions in the market for equity funds. The DGM estimates of the MRP are the only truly forward-looking estimates that indicate prevailing conditions in the market for equity funds.

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74 Economic Regulation Authority, Draft Explanatory Statement for the Rate of Return Guidelines (2018), 29 June 2018, Para 524

75 CEPA, Expert Joint Report, 21 April 2018, pg 59

76 Economic Regulation Authority, Draft Explanatory Statement for the Rate of Return Guidelines (2018), 29 June 2018, Para 526

77 Lally, M., Review of the AER's Methodology for the Risk Free Rate and the Market Risk Premium, 4 March 2013, p. 40.

78 Lally, M., The Cost of Equity and the Market Risk Premium, 25 July 2012, p. 31-32

The evidence cited by the draft Guidelines for lowering the weight given to the DGM approach consists primarily of statements made by Partington and Satchell in an April 2017 report to the AER. These statements express concerns about the reliability of the DGM to set a MRP allowance.

These concerns about the DGM approach were known to (and considered by) the ERA in 2013, when it was developing its 2013 Rate of Return Guidelines, and in its subsequent decisions for rail and energy networks.

Our proposed MRP estimate places material weight on the DGM estimate as there is no new evidence to discredit the use of the DGM. Placing material weight on the DGM estimates recognises that the MRP is a forward-looking estimate. The evidence of the weights adopted by the ERA suggests that a 50% weight could reasonably be applied to the DGM estimate. This would result in an MRP estimate that considers all relevant estimates, the prevailing conditions in equity markets and accordingly gives rise to the best empirical estimate of the MRP, necessary for the achievement of the NGO.

### Calculating the MRP

Both approaches for estimating the MRP—historical excess returns and the DGM—have their own strengths and weaknesses:

- The Ibbotson approach is relatively simple to implement and is well-accepted by practitioners, including some regulators. However, average historical excess returns are unlikely to reflect the prevailing market conditions for funds unless prevailing market conditions happen to correspond to 'average' or 'normal' market conditions. Historical average excess returns would be a suitable method for estimating the MRP if the objective were to estimate the return required by equity investors over the very long-run (e.g., 100+ years). However, that is not the regulatory task. The regulatory task is to estimate a rate of return that reflects the prevailing conditions in the market for equity funds.
- The DGM is more likely to reflect prevailing market conditions than is the Ibbotson approach. However, the ERA has expressed concerns about some of the limitations of the DGM approach.

Given that neither of these approaches is ideal, and that both likely have useful information to contribute to a robust estimate of the MRP, we have given equal weight to both approaches. In other words, we propose to determine the MRP as the mid-point between the arithmetic mean of the historical MRP and the DGM estimates through the following formula:

$$MRP = \frac{HER_{arithmetic} + DGM}{2}$$

where

$MRP$ is the market risk premium point estimate;

$HER_{arithmetic}$ is the estimate of the MRP derived using the arithmetic mean of historical excess returns; and

$DGM$ is the dividend growth model estimate of the MRP.

The benefit of this approach is that it equally acknowledges both the historical excess returns and the DGM as relevant evidence. A MRP estimated in this way will allow reference tariffs to provide a return commensurate with the regulatory and commercial risks involved in providing reference services as it gives appropriate material weight to estimates of a forward-looking return that is commensurate with the prevailing conditions in financial markets.

Our proposed MRP estimate is based on the information available at the time of publication of the draft Guidelines. Our estimate of the MRP, using the approach presented above, results in 6.9%.

## 14.5 Cost of debt

We have estimated the cost of debt by adopting the ERA's approach to estimating the cost of debt, incorporating a hybrid trailing average with an annual update of the debt risk premium (**DRP**), consistent with the draft Rate of Return Guidelines.

Consistent with the ERA's hybrid trailing average method, we have estimated the cost of debt as the risk-free rate for debt plus a DRP (updated annually), and an allowance for debt raising and hedging costs. We have estimated the risk-free rate for debt using the 5-year bank bill swap rate as a proxy. The cost of debt formula is:

$$r_d = BBSW_5 + DRC + Hedging + DRP_{Trailing}$$

where:

$r_d$ is the cost of debt

$BBSW_5$ is the 5-year bank bill swap rate

$DRC$ is the debt raising costs

$Hedging$ is the cost of hedging (swaps) that converts floating-rate interest payments to fixed-rate interest payments, or vice versa

$DRP_{Trailing}$ is the 10-year trailing average debt risk premium consistent with the average term of benchmark debt.

Our estimate of the DRP will be varied annually during the regulatory period. The process to update the return on debt is described in Section 14.5.3.

### 14.5.1 Debt raising and hedging costs

We propose to include debt raising and hedging costs. We have adopted 0.100% and 0.114% respectively consistent with the values specified in the draft Rate of Return Guidelines.

### 14.5.2 Risk free rate (cost of debt)

The risk-free rate is calculated from the 5-year bank bill swap rate as the proxy for the risk-free rate.

For this submission, we have calculated the risk-free rate over the 20 trading days to 29 March 2018 as a placeholder. We will separately and confidentially notify the ERA of the average period we intend to adopt for AA5.

### 14.5.3 Debt risk premium

We have estimated the DRP consistent with the hybrid trailing average approach applied in AA4 and consistent with the draft Rate of Return Guidelines.

The Revised Bond Yield Approach consists of the following six processes:

1. **Determining the benchmark sample:** Identifying a sample of bonds based on the benchmark sample selection criteria. This will include a 'cross-section' of bonds.
2. **Collecting data:** Collecting data for those bonds over the averaging period in question, for example, 20 trading days. This represents 'time series' data relating to each bond.

3. **Converting yields to Australian dollar equivalents:** Converting yields for bonds denominated in foreign currencies into Australian dollar (AUD) equivalents so that all yields are expressed as an AUD equivalent.
4. **Averaging yields over the averaging period:** Calculating an average AUD equivalent bond yield for each bond in the cross-section across the averaging period. For example, where a 20-trading day averaging period applies, each bond will have a single 20-day 'average yield' calculated.
5. **Estimating 'curves':** Estimating three yield curves based on different methodologies and using the average yield for each bond, its remaining term to maturity, and AUD face value.[79]
6. **Calculating the DRP:** Calculating the DRP by subtracting the average of the 10-year AUD interest rate swap rate from the 10-year cost of debt estimate, with the latter calculated as the average of the three estimated yield curves at the 10-year tenor.

### *14.5.3.1 Credit rating*

We propose to estimate the DRP based on a sample of bonds in the BBB+ credit rating for the debt consistent with the draft Rate of Return Guidelines. We understand that the ERA's application of the BBB+ credit rating will be forward-looking and will apply to each year's DRP from 2019. The current BBB-/BBB/BBB+ credit band will continue to be adopted to compute each year's DRP to 2019.[80]

### *14.5.3.2 Term of debt*

We propose a 10-year term of debt to estimate the DRP for this access arrangement, consistent with the draft Rate of Return Guidelines. The term of debt used to calculate the DRP represents the average term of debt of a benchmark efficient entity and its staggered debt portfolio. The ERA has used a 10-year term of debt in its recent regulatory decisions.

### *14.5.3.3 Trailing average DRP calculation*

The trailing average DRP is calculated using the following formula:

$$TA\ DRP_0 = \frac{\sum_{t=0}^{-9} DRP_t}{10}$$

Where:

$TA\ DRP_0$ is the equally weighted trailing average of the debt risk premium to apply in the following year as the annual update of the estimate used in the current year; and

$DRP_t$ is the debt risk premium estimated for each of the ten regulatory years t = 0, -1, -2..., -9.

We will continue to adopt the historical $DRP_t$ values adopted in the ERA's AA4 Final Decision and determined during AA4. This is on the basis that we have made commercial decisions based on these historical values, and it would be inconsistent with the NGO for these values to be changed. For this submission, we have adopted the 2020 calendar year DRP across all years of AA5, noting that there is an annual update process that will adjust for any differences. The $DRP_t$ values adopted for the 2020 calendar year are shown in Table 14.4.

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79 The three curves are based on the Gaussian Kernel, the Nelson Siegel and the Nelson Siegel Svennson methodologies. The Gaussian Kernel approach produces a series of point estimates as opposed to a curve. However, each point estimate can be seen as points that compose a curve.

80 Economic Regulation Authority, Draft Explanatory Statement for the Rate of Return Guidelines (2018), 29 June 2018, Appendix 2, Para 4

**Table 14.4:** $DRP_t$ values included in the 2020 estimate of the trailing average DRP

| CALENDAR YEAR | $DRP_t$ | METHOD |
|---|---|---|
| 2011 | 2.371% | Adopted AA4 Final Decision value |
| 2012 | 3.172% | Adopted AA4 Final Decision value |
| 2013 | 3.068% | Adopted AA4 Final Decision value |
| 2014 | 2.250% | Adopted AA4 Final Decision value |
| 2015 | 1.953% | Adopted AA4 Final Decision value |
| 2016 | 2.467% | Adopted the value determined for the 2016 Tariff Variation Mechanism |
| 2017 | 2.326% | Adopted the value determined for the 2017 Tariff Variation Mechanism |
| 2018 | 1.689% | Adopted the value determined for the 2018 Tariff Variation Mechanism |
| 2019 | 1.689% | Forecast – to be calculated using the automatic formula DRP estimate under the 2019 Tariff Variation Mechanism |
| 2020 | 1.689% | Forecast – to be calculated using the automatic formula DRP estimate under the ERA's Final Decision |

#### *14.5.3.4 Annual update process*

The annual update operates by adding in the most recent estimate of the DRP and dropping the estimate from ten years ago. This replicates the cost of debt for the benchmark efficient entity under a strategy whereby it rolls over 10% of its debt each year.

The annual update of the DRP feeds through into the annual tariff variation and is discussed further in Section 14.7 below.

## 14.6 Other parameters

### 14.6.1 Gearing

We have adopted a benchmark debt gearing ratio of 55%, consistent with the draft Rate of Return Guidelines. This is changed from AA4 where 60% was adopted.

### 14.6.2 Forecast inflation

Our forecast inflation uses the Fisher Equation to estimate the implied inflation rate from 5-year Australian Commonwealth Government Securities and their 5-year indexed yields. This is consistent with the draft Rate of Return Guidelines. For this submission, we have forecast inflation of 1.84% using the CGS yields over the 20 trading days to 29 March 2018 as a placeholder. We will separately and confidentially notify the ERA of the average period we intend to adopt for AA5.

### 14.6.3 Equity raising costs

Equity raising costs reflect the costs associated with the benchmark efficient entity raising equity to fund its investment program to maintain the benchmark gearing assumption adopted in the rate of return. We have calculated that no equity raising costs will be required over AA5.

Should we need to calculate equity raising costs in the future, we will use the method adopted in AA4. This method estimates equity raising costs based on the following assumptions (that are unchanged from AA4):

- Retained earnings of 30% of after-tax profits will be available to increase equity at zero cost.
- Dividends will be assumed to be paid at the benchmark payout ratio of 70% of after-tax profits.
- 25% of dividends paid out will be treated as being reinvested through dividend reinvestment plans, with an equity raising cost allowance of 1%.
- Any further required equity is raised at the Seasoned Equity Offering cost of 3%.

Equity raising costs are capitalised into the regulatory asset base (**RAB**) and will be recovered over 53 years (based on the weighted average economic life of the RAB as at 1 January 2020).

## 14.7 Annual updating

The estimated rate of return will be updated annually during AA5 to account for the annual update to the DRP component of the cost of debt. The first annual update of the rate of return will apply as part of the tariff variation for the 2021 calendar year with subsequent annual updates in the 2022, 2023, and 2024 calendar years.

The annual update will be determined based on the formulas set out in detail in the Rate of Return Guidelines. The resulting annual adjustment to the rate of return will be incorporated in the Annual Tariff Variation for the years 2021, 2022, 2023 and 2024.

We anticipate that under the Rate of Return Guidelines, the process for implementing the annual update will continue to be as follows:

- For each annual update for 2021, 2022, 2023, and 2024, the ERA will estimate the updated DRP following the relevant annual averaging period, recalculate the rate of return, and then notify us of the outcomes as soon as practicable. This process will allow us to check the rate of return estimate, prior to its incorporation in the proposed annual tariff variation.
- Following that notification, we are required to respond on any issues as soon as practicable, to allow the updated DRP and rate of return estimates to be finalised prior to the submission of our proposed annual tariff variation.
- If there is a disagreement on the DRP annual update estimate, the ERA will work with us to ensure that any misapplication of the automatic formulas is corrected in a timely manner.
- The updated annual rate of return based on the correct application of the DRP automatic update formulas is to be utilised for each annual tariff variation.

# 15. Gamma and cost of tax

**CHAPTER HIGHLIGHTS**

1. We estimate that our cost of tax over AA5 is $11.9 million.
2. The cost of tax is part of doing business.
3. We have calculated the value of gamma using ATO tax statistics.

## 15.1 Introduction

We calculate the estimated cost of corporate income tax as part of determining our building block revenue requirement for AA5. We have calculated an estimate of our corporate income tax expense by considering forecast revenue, opex, interest on debt, and tax depreciation.

Table 15.1 presents the statutory income tax rate and the value of imputation that have informed our application of Rule 87A to calculate the cost of tax.

**Table 15.1:** AA5 proposed gamma and cost of tax

| PARAMETER | PROPOSED VALUE |
| --- | --- |
| Corporate Tax Rate | 30% |
| Franking Credit (gamma) | 0.34 |

This chapter explains our approach to estimating the cost of tax, including how we have deviated from the Draft Rate of Return Guidelines to derive the value for gamma.

## 15.2 Stakeholder engagement

We sought feedback from stakeholders on whether our proposed method and calculation for gamma and the cost of tax were reasonable. We received feedback from Retailer B on our Draft Plan (published in May 2018) that supported us following the ERA's Rate of Return Guidelines upon publication.

Retailer B's submission identified that the AER's review into its approach to regulatory tax will be of interest to the ERA. Our view is that the AER's review should focus on estimating the corporate tax that would be paid by the benchmark efficient entity, within the context of the Australian regulatory framework. We note that the ERA has previously estimated the tax building block based on the benchmark efficient entity.

The ERA's approach to the calculation of the tax building block differs in one important aspect from the AER due to a different treatment of the tax liability associated with the receipt of capital contributions. For this submission, we have not made any changes and have continued to apply the ERA's method to calculate the tax building block, identical to the method adopted in AA4.

Table 15.2 summarises our response to stakeholder's feedback.

**Table 15.2:** Consideration of stakeholder feedback on gamma and cost of tax

| DRAFT PLAN STAKEHOLDER QUESTION | STAKEHOLDER FEEDBACK | OUR RESPONSE TO FEEDBACK ON OUR DRAFT PLAN |
|---|---|---|
| Do you consider our calculations for gamma and the cost of tax to be reasonable?<br><br>Do you have any comments on the methods we have used in our calculations? Do you believe they are reasonable? | Retailer B supports the initial adoption by ATCO of the method used by the ERA for DBNGP and anticipate ATCO following the ERA's Rate of Return Guidelines upon publication. | **Change** – We have further considered the available information on the calculation of gamma since publishing our Draft Plan in May 2018. In this submission, we have calculated the value of gamma as 0.34 using ATO tax statistics. |
| | Retailer B notes the Australian Energy Regulator (AER) has this month launched a review into its approach to regulatory tax following identification by the Australian Taxation Office (ATO) of several drivers causing an apparent material discrepancy between the tax allowances set by the AER and the actual tax payments made to the ATO by regulated networks. The AER intends to examine the drivers and consider how the differences might be addressed. An initial public report is anticipated in June, with a final report and recommendations by December. Retailer B expects the ERA will follow the AER's review with interest. | **No change** – We have continued to apply the ERA's method to calculate the tax building block, identical to the method adopted in AA4. |

## 15.3 Gamma

We have calculated the value of gamma using published ATO aggregate tax statistics. This approach calculates gamma as the proportion of created credits that are redeemed by investors in Australia. Under this approach, gamma is estimated directly as the ratio of total credits redeemed to total credits created, where each component is obtained from official ATO taxation statistics. Gamma is estimated as:

$$\gamma = \frac{Credits\ redeemed}{Credits\ created}$$

This approach has three benefits:

- It eliminates the need to estimate separately the distribution rate and the utilisation rate, thereby simplifying the estimation process considerably.
- It avoids significant matters of contention that surround the estimation of these individual parameters.
- By making use of ATO tax statistics data, it provides a direct estimate of gamma that reflects the actual behaviour of investors eligible to redeem tax credits in Australia.

The ATO provides data on the quantum of credits that are created each year and on the quantum of credits that are redeemed each year. There has never been any dispute about either of these items, and these are the only two items that are needed to estimate gamma. In June 2018, Hathaway confirmed that gamma can be estimated directly as the ratio of credits redeemed to credits created from ATO tax statistics.[81]

The most recent estimate of gamma using the ATO data is 0.34. This estimate is constructed using data from 2004 to 2015; the latest data available from the ATO.

In the draft Rate of Return Guidelines, the ERA estimates gamma at 0.5, calculated as the product of a distribution rate of 0.83 (Lally's estimate based on the 20 largest ASX listed firms) and a utilisation rate of 0.60 (using an equity ownership approach). We do not consider this approach gives rise to the best estimate of gamma because:

1. The distribution rate of 0.83 does not reflect an estimate consistent with the benchmark efficient entity, and there are several unresolved issues with the estimates provided by Lally.
2. In respect of the equity ownership estimate of 0.60, the data upon which this estimate is based (ABS data) is subject to quality warnings by the ABS and is subject to several discrepancies.

It is an internally inconsistent approach that involves estimating the proportion of credits that are distributed to one group of shareholders and the proportion that are redeemed by an entirely different group of shareholders. This is inconsistent with the 'cash flow' interpretation of gamma.

Estimating gamma using different and inconsistent approaches and data for the two components does not result in an appropriate estimate of gamma consistent with the NGO and the Revenue and Pricing Principles.

We submit that internal consistency is particularly important under the 'cash flow' interpretation to gamma. Frontier Economics notes that the 'cash flow' or 'utilisation' interpretation of gamma seeks to determine how much of the corporate tax paid by the benchmark efficient entity will be returned to its shareholders via the redemption of imputation credits.[82] This interpretation requires consistent estimation of the distribution rate and the utilisation rate. That is, some proportion of credits will be distributed to the benchmark efficient entity shareholders, who will then redeem some of those credits. The corporate tax allowance is then reduced by the amount of credits that are redeemed back by the benchmark efficient entity shareholders.

Under the 'cash flow' interpretation of gamma it would make little sense to take the proportion of credits distributed to the benchmark efficient entity shareholders and to pair that with the proportion of credits redeemed by some other group of shareholders.

The Frontier Economics report notes that the cash flow interpretation of gamma can be implemented either by:

- Using the 'all equity' sample to proxy for the benchmark efficient entity, in which case gamma can be estimated directly from ATO tax statistics as the ratio of credits redeemed to credits created. This approach produces an estimate of 0.34; or
- Using the listed equity sample to proxy for the benchmark efficient entity, in which case gamma can be estimated as the product of a distribution rate (estimated using the Dr Lally '20-firms' approach or some other approach using a broader sample of listed equity) and the equity ownership approach for listed equity. This approach produces an estimate of 0.39, which is an upper-bound on the value of gamma. The 20-firms estimate for listed equity is an upper-bound because the Franking Account Balance can fall for reasons other than the distribution of credits to shareholders. The equity

81 Hathaway, N., Capital Research Memorandum, 28 June 2018, Available from: https://www.aer.gov.au/system/files/ENA%20-%20Capital%20Research%20Memorandum%20-%2028%20June%202018.pdf

82 See Attachment 15.1: *'The 'Utilisation' estimate of gamma. Frontier Economics'* August 2018

ownership estimate for listed equity is an upper-bound because resident investors do not (and cannot) redeem all the credits that they receive.

Thus, for listed equity, the evidence supports a gamma range of 0.34 to 0.39.

We submit that gamma should be estimated directly from ATO data as it provides a direct and reliable estimate of gamma. This approach:

- produces stable estimates over time;
- is transparent and repeatable;
- uses publicly available data that is easy to access;
- provides a direct estimate from a single source of data;
- does not require the separate estimation of the distribution rate; and
- is internally consistent.

Our position is supported by the attached report from Frontier Economics, which we commissioned to set out the best estimate of gamma under a 'utilisation' interpretation of gamma (see Attachment 15.1).

## 15.4 Tax lives

We have applied tax asset lives to the tax asset base that are consistent with guidance provided by the ATO, as shown in Table 15.3.

We have added a new asset category to the tax asset base in AA5 for Telemetry, given our increasing investment in telemetry and monitoring systems, including SCADA. The tax life adopted is ten years consistent with the guidance from the Commissioner for Taxation in taxation ruling TR 2017/2 for the Gas Supply industry.

**Table 15.3:** Tax lives (years)

| ASSET CATEGORIES | AA4 | AA5 |
|---|---|---|
| **CURRENT AND NEW ASSET CATEGORIES** | | |
| HP mains – steel | 20.0 | 20.0 |
| HP mains – PE | 20.0 | 20.0 |
| Medium and low pressure mains | 20.0 | 20.0 |
| Regulators | 40.0 | 40.0 |
| Secondary gate stations | 40.0 | 40.0 |
| Buildings | 40.0 | 40.0 |
| Meter and services pipes | 25.0 | 25.0 |
| Equipment and vehicles | 10.0 | 10.0 |
| Information technology | 4.0 | 4.0 |
| Land | - | - |
| Equity raising cost | 5.0 | 5.0 |
| Telemetry | N/A | 10 |
| **HISTORICAL ASSET CATEGORIES** (NO LONGER USED FOR NEW EXPENDITURE) | | |
| Medium pressure mains | 20.0 | 20.0 |
| Low pressure mains | 20.0 | 20.0 |

## 15.5 Establishing the opening AA5 tax asset base

The tax asset base (**TAB**) is a primary input into the calculation of the cost of tax. We have calculated the opening value of the TAB using the roll-forward method to roll forward the value of the TAB from the opening value at the start of AA4. Similar to rolling forward the RAB, the forecast AA5 TAB calculation considers:

- **Opening value at 1 July 2014:** The opening value of the TAB at the commencement of AA4 will be the starting point for the roll forward of the TAB.
- *Plus* **Capex:** Actual capex (net of capital contributions) incurred over AA4 and the forecast capex (net of capital contributions) over AA5 will be rolled into the TAB.
- *Less* **Depreciation:** Depreciation based on the actual capex over AA4 and the forecast capex to be incurred over AA5 will be deducted from the TAB.
- *Less* **Asset disposals:** Asset disposals based on the actual asset disposals over AA4 at the nominal value removed from the RAB.

Table 15.4 details the roll-forward of the tax asset base over AA4.

**Table 15.4:** Roll forward of tax asset base over AA4 ($M nominal)

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|
| Opening value | 467.2 | 484.3 | 511.0 | 546.0 | 581.3 | 623.9 |
| *Plus,* capex (net) | 40.2 | 75.5 | 87.9 | 89.1 | 96.5 | 88.6 |
| *Less*, tax depreciation | -23.0 | -48.8 | -52.6 | -53.6 | -54.0 | -57.9 |
| *Less,* asset disposals | -0.0 | -0.0 | -0.2 | -0.2 | - | - |
| **Closing value** | **484.3** | **511.0** | **546.0** | **581.3** | **623.9** | **654.6** |

## 15.6 AA5 tax asset base

Table 15.5 details the rolling forward of the TAB over AA5 and the resulting tax depreciation values adopted in the calculation of our estimate of corporate income tax. We have continued to apply tax asset lives that are consistent with the ATO guidance.

**Table 15.5:** Roll forward of tax asset base over AA5 ($M nominal)

| | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|
| Opening value | 654.6 | 697.7 | 736.5 | 771.9 | 807.7 |
| *Plus,* capex (net) | 105.3 | 106.0 | 106.0 | 109.9 | 110.9 |
| *Less,* tax depreciation | -62.2 | -67.2 | -70.6 | -74.1 | -78.7 |
| *Less, asset disposals* | - | - | - | - | - |
| **Closing value** | **697.7** | **736.5** | **771.9** | **807.7** | **839.9** |

## 15.7 Estimate of corporate income tax

We have calculated our estimate of corporate income tax using the same method we applied in AA4. Our approach is first to estimate taxable income as follows:

Smoothed tariff revenue

*plus* Revenue from prudent discounts.

*plus* Ancillary reference service revenue.

*minus* Approved forecast opex.

*minus* Depreciation of the tax asset base, excluding capital contributions. Tax depreciation is applied on a straight-line basis.

*minus* Debt servicing costs, calculated by multiplying the debt portion of the opening RAB by the debt to equity ratio (assumed at 60%) and the nominal hybrid trailing average cost of debt (based on the trailing average estimate of the debt risk margin, annually updated, plus the 'on the day' nominal risk-free rate).

*equals* Estimated taxable income.

We then apply the statutory tax rate of 30% and the value of imputation credits to the estimated taxable income to determine our estimate of corporate income tax. The estimate of corporate income tax is shown in Table 15.6.

**Table 15.6:** Estimate of corporate income tax ($M nominal)

| | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|
| Estimated taxable income | 22.4 | 18.3 | 15.1 | 13.3 | 11.4 |
| Tax payable | 6.7 | 5.5 | 4.5 | 4.0 | 3.4 |
| Less value of imputation credits | -2.3 | -1.9 | -1.5 | -1.4 | -1.2 |
| **Est. of corporate income tax** | **4.4** | **3.6** | **3.0** | **2.6** | **2.3** |

# 16. Working capital

**CHAPTER HIGHLIGHTS**

1. We have calculated working capital in accordance with the method in the ERA's AA4 Final Decision tariff model.
2. Parameters used in our calculation have been updated from the ERA's AA4 Final Decision tariff model to reflect current working capital requirements.

## 16.1 Introduction

Working capital refers to a stock of funds that we must maintain to pay costs as they fall due, and inventory held to meet service requirements within mandated or reasonable service delivery times. The cost of this stock of working capital (being the required return on the capital investment) is incurred during everyday business operations and the provision of reference services.

The requirement to maintain a stock of funds arises from the misalignment (on average) between incurring the costs of providing services and recovering the revenues associated with the provision of those services. In addition, a stock of materials is held to allow the efficient and timely provision of services. The cost of working capital reflects the return on the capital funds required to be maintained. These costs represent the efficient costs of a business that receives revenue at a different time to when it incurs costs.

## 16.2 Stakeholder engagement

We published our 2020-24 Draft Plan at the beginning of May 2018 and invited feedback from stakeholders. Several retailers and other parties provided feedback. The feedback relevant to working capital is summarised in Table 16.1.

**Table 16.1:** Stakeholder feedback - Working capital

| DRAFT PLAN STAKEHOLDER QUESTION | STAKEHOLDER FEEDBACK | OUR RESPONSE TO FEEDBACK ON OUR DRAFT PLAN |
|---|---|---|
| 28: Do you consider our calculation for working capital to be reasonable?<br>29: Do you have any comments on the methods we have used in our calculations? Do you believe they are fair and reasonable? | Retailer B has questioned the increase in working capital receivables days noting their payment terms are 14 days. | **No change.** We have prepared our working capital calculation taking account of the time between when a haulage service is provided, and when the service is invoiced. That time gap is on average 40 days (refer to Table 16.3). The unbilled revenue time gap of 40 days is in addition to the time gap between invoicing haulage services and receiving payment. We expect that the cost of reducing the unbilled haulage service days, by for example, increasing meter reading frequency, is greater than the return on this component of working capital. Our approach to calculating receivable days is based on regulatory precedent. |

Although we understand the reasons for stakeholder feedback concerning working capital, we do not intend to change the days receivable parameter because it is supported by regulatory precedent, the meter reading cycle, the billing cycle, and the underlying payment terms.

## 16.3 Forecast working capital

We have estimated the cost of capital using the '*working capital cycle model*' as previously accepted by the ERA. This cost is calculated as the difference between the implicit cost incurred by providing credit to users of the service, and the implicit benefit of receiving credit from suppliers. The working capital cycle is comprised of three core components: *inventory, creditors, and receivables.*

Although the method used is the same as AA4, the parameters applied to each component of working capital have been reviewed and amended where necessary.

- **Inventory:** We have maintained the assumption that an efficient level of inventory is 0.89% of the annual capex. Based on data available for 2017, inventory as a percentage of capex was 1.04%. We do not consider this difference material enough to justify amending the inventory parameter from the previously approved value.
- **Creditors:** We have adjusted our creditor's assumptions for AA5. Accounts payable creditor days have been re-evaluated taking account of the payment terms relating to labour costs, general creditors, and payment for UAFG. The weighted average creditor days is 19. The calculation of creditor days is shown in Table 16.2.
- **Receivables:** Receivables days have been re-evaluated taking account of the days of unbilled haulage that were inadvertently excluded in the calculation of receivables days for AA4. Unbilled haulage reflects the incurred costs to provide reference services, for which revenue has not yet been received. The inclusion of this amount in working capital is consistent with the ERA's AA3 Western Power Final Decision. The calculation of total receivables days is shown in Table 16.3.

**Table 16.2:** Calculation of creditor days

| CREDITOR ELEMENT | WEIGHTING | DAYS |
|---|---|---|
| Labour | 32% | 1.7 |
| Non-labour | 64% | 27 |
| UAFG | 4% | 44 |
| **TOTAL CREDITOR DAYS** | | **19** |

**Table 16.3:** Calculation of receivables days

| RECEIVABLES ELEMENT | DAYS |
|---|---|
| Average unbilled revenue days – based on the meter reading schedule | 40 |
| Average days from meter read to invoice - based on billing twice a month | 7 |
| Days to issue invoice | 1 |
| Days from invoice to payment - payment terms are 10 business days | 14 |
| **TOTAL RECEIVABLES DAYS** | **62** |

Table 16.4 shows the working capital parameters.

**Table 16.4:** Working capital parameters

| PARAMETER | AA4 | AA5 | BASIS OF CALCULATION |
|---|---|---|---|
| Inventory as a % of capex | 0.89% | 0.89% | Based on 2017 inventory as a percentage of 2017 capex. |
| Creditors | 15 days | 19 days | Determined from the standard terms of payment to suppliers, labour, and suppliers of UAFG. The amount relates to total expenditure including capex. |
| Receivables | 18 days | 62 days | Determined from the payment terms of our contracts with retailers. |

Table 16.5 sets out the working capital value for AA5 based on the above assumptions.

The 2020 opening working capital value is the closing working capital value in the ERA's AA4 Final Decision tariff model as varied in annual tariff variations up to and including 2018.

A return on opening working capital is included in "Total revenue" for each year of the access arrangement period, as shown in Table 16.5.

**Table 16.5:** Return on working capital

| RETURN ON WORKING CAPITAL | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|
| Opening working capital ($nominal) | 1.3 | 24.3 | 25.3 | 26.2 | 27.0 |
| WACC (nominal) | 6.03% | 6.03% | 6.03% | 6.03% | 6.03% |
| Return on working capital ($nominal) | 0.1 | 1.5 | 1.5 | 1.6 | 1.6 |
| Deflator to $real 2019 | 1.018 | 1.037 | 1.056 | 1.076 | 1.095 |
| Return on working capital ($real 2019) | 0.1 | 1.4 | 1.4 | 1.5 | 1.5 |

# 17. Incentive mechanisms

**CHAPTER HIGHLIGHTS**

1. We are proposing a mechanism to incentivise innovation for AA5: The Network Innovation Scheme.
2. We do not have any incentive mechanisms in our current access arrangement.

## 17.1 Introduction

Over AA5, we expect the Western Australian energy market to continue to undergo rapid change, with renewable energy revolutionising the way energy networks operate. We believe our gas network has an important role to play in supporting the decarbonisation of the energy sector as well as offering a solution that balances environmental issues, cost, and security.

During this time of rapid technological change, innovation in our business is a major focus. The integration of new technologies into our network provides opportunities to improve our services and allow better responsiveness to customer choice.

To incentivise investment in innovative technologies, we are proposing a *network innovation scheme* for AA5. We do not currently have any incentive mechanisms in AA4.

The Network Innovation Scheme (**NIS**) outlined in this 2020-24 Plan shares some of its significant features with the AER's Demand Management Innovation Allowance (**DMIA**) available under the Demand Management Incentive Scheme (**DMIS**). This Scheme allows electricity distributors in the National Electricity Market to seek additional funding (generally through opex) to manage peak demand on the network instead of investing in network augmentation.

The electricity distributors apply to the AER for amounts up to $1 million per year to invest in demand management (but only recover the amount they spend below this cap). As such, our proposed NIS is modest, targeted, and accountable. The Scheme is intended to support small-scale innovation projects to underpin our introduction of new network services that have the potential to deliver long-term benefits for gas consumers but have an uncertain probability of success.

## 17.2 Stakeholder engagement

We sought feedback on our Draft Plan (published in May 2018) regarding our proposed NIS. In the main, stakeholders were broadly supportive of innovative energy solutions that benefit customers. However, stakeholders also indicated that they would need further detail on the scheme, and the types of innovation projects to be included, before they could express a final position on the merits of the proposed scheme. Table 17.1 summarises the feedback received and our respective response.

**Table 17.1:** Stakeholder feedback on the Network Innovation Scheme

| DRAFT PLAN STAKEHOLDER QUESTION | STAKEHOLDER FEEDBACK | OUR RESPONSE TO FEEDBACK ON OUR DRAFT PLAN |
|---|---|---|
| Do you believe an increase in innovation activity is important to address the future challenges of our energy environment? | In the main, stakeholders were positively disposed towards innovation as an activity and generally supported the development of innovative energy solutions that benefit end-use customers. | The Network Innovation Scheme proposed in this 2020-24 Plan is intended to overcome the disincentive for innovation that is created through the standard application of incentive-based regulation and reflect the requirements of Rule 98 of the NGR. |
| Do you believe the current regulatory framework has sufficient incentives for innovation? If not, how should the framework be modified?<br><br>Do you believe the regulatory framework is the most suitable mechanism to increase innovation? If not, what other mechanisms do you consider to be most suitable? | **Retailer A** indicated that "at a high-level the proposed Network Innovation Scheme's design features and principles appear consistent with the regulatory framework provided that the costs of the scheme are reviews and outcomes held accountable, with any benefits being shared with customers through reduced tariffs." | We agree with this feedback and has proposed a Network Innovation Scheme that is consistent with the NGO and the Pricing and Revenue Principles. It is also modest in scope and will be operated in a transparent and accountable manner. |
| Do you have any comments on our proposed Network Innovation Scheme? Do you believe the associated design features and principles are sufficient to encourage greater innovation? | Stakeholders were keen to see further detail on how the proposed network innovation scheme is intended to operate.<br>For example, stakeholders were keen for further detail on the types of projects and activities expected to be covered by the scheme, the criteria that would guide project selection, and the expected cost of the scheme. | We have provided further detail on these matters in this 2020-24 Plan.<br>As well as providing more detail on the operation of the scheme and the criteria guiding project selection, we have included a comprehensive discussion of the innovation challenge facing network businesses like ATCO. |

## 17.3 Our innovation challenge

We operate in an increasingly diverse, contestable, and competitive energy services market. The competitiveness of this market means that, at a minimum, we need to focus on efficient service delivery, and facilitating upstream and downstream competition. Since we are already operating efficiently, the business would benefit from stronger incentives to take risks and invest in innovation.

We need to innovate to continue to deliver services that are in the long-term interest of gas customers. However, the available mechanisms under the natural gas regulatory framework do not provide adequate incentive for the business to invest in innovative technologies. This lack of incentive is a challenge for our business because:

- the returns provided under the current framework do not provide headroom for research and development risk; and,

- regulated energy businesses face different incentives to invest in innovation compared to unregulated businesses.

Under conventional expenditure tests, regulated businesses are generally incentivised to focus on short-term projects aimed at operational efficiencies within an access arrangement period, rather than innovation that could deliver benefits over multiple access arrangement periods.

Innovation, by its very nature, requires a network business to incur up-front costs in the short to medium-term on initiatives with uncertain long-term payoffs. Consequently, network businesses could be deterred from innovations that have potential (but uncertain) long-term benefits in the form of lower costs, or new and improved services required by customers.

A further disincentive for ATCO and other network businesses is that these benefits may accrue over multiple regulatory periods, which are based on shorter-term approved expenditure cycles.

## 17.4 The importance of innovation

### 17.4.1 Defining innovation

In our view, innovation primarily involves both the creation and diffusion of new products, processes, and methods. Innovation comprises a wide range of activities, including research and development (**R&D**), organisational training, design, testing, and marketing.

Innovation can be further categorised as being either 'new to the world' or 'new to the firm'[83]. Innovations are new-to-the-world when their effect is felt across all markets and industries. These can include general purpose technologies, such as electricity and the internet, which have wide applicability and open up new opportunities rather than offering complete, final solutions.

New-to-the-firm innovation reflects the individual firm's adaptation of innovation in *its specific market context*. New-to-the-firm innovation includes the adoption of new-to-the-world innovations.

### 17.4.2 The economic contribution of innovation

It is well-established in the economic literature that innovation, whether it be new-to-the-world or new-to-the-firm innovation, is a major driver of economic efficiency and in so doing, economic growth.

This is important in the context of the regulatory framework embodied in the NGL and NGR, which is underpinned by an economic efficiency objective (the NGO). Network businesses will need to innovate to maintain the relevance of their network services in the face of considerable technological change sweeping across the Australian energy market. This raises important issues regarding the design of the NGL and NGR and specifically the innovation incentives for gas network businesses.

### 17.4.3 Innovation as a response to a rapidly shifting energy landscape

Over the past decade, the way gas and electricity networks operate has been changing to keep pace with these broader macro shifts. This includes accommodating a more complex energy system characterised by a rapidly increasing amount of renewable generation, changing consumer energy demand patterns, and the breakdown of the old centralised energy model due to distributed generation. In addition, new fuels, such as biogas and hydrogen, have the potential to become mainstream and complementary energy solutions using the existing gas network infrastructure.

[83] Palangkaraya A., Spurling T., Webster E, (2016), What drives firm innovation? A review of the economics literature", April.

There is widespread recognition that these broader energy market changes mean that gas networks such as ours will need to innovate and evolve. These innovations may include:

- handling different blends of gas (including hydrogen and biogas, as opposed to just natural gas) as part of the decarbonisation of the energy supply; and
- providing enhanced services, such as energy storage, to meet the evolving needs and expectations of current and prospective customers.

The scale of the existing gas network infrastructure in WA and its significance for customer energy consumption emphasises the importance of leveraging contemporary and prospective advances in energy technology in network service provision.

Changes in the broader energy market, including new sources of energy, are likely to have large future effects on the operation of gas networks, but the regulatory framework hinders the ability of network businesses to prepare for any such changes because it is predicated on a stable technological change assumption with substantially unchanged energy supply and demand patterns. This tension emerging in the design and administration of energy regulatory frameworks is discussed further in Section 17.5.

## 17.5 Innovation under economic regulatory frameworks

### 17.5.1 Barriers to energy network innovation

Until recent times, gas and electricity network service provision has been characterised by relatively slow technological change, such that their essential service characteristics have been assumed to remain broadly stable over time.

The design of Australia's national energy regulatory framework fundamentally reflects this characterisation of the core network service, which continues to be regulated as a natural monopoly service, in contrast to the contestable sectors of the energy supply chain. However, energy regulation is now being applied in an increasingly dynamic energy market setting, which is becoming more akin to the telecommunications network sector. This is raising challenges in the application of economic regulation that has typically applied in the latter sector.

Notwithstanding ongoing work and refinements to the framework initiated by the COAG Energy Council and Australian Energy Market Commission, there is an increasing risk that the framework (or administration of the framework) will be too slow to respond to energy market change. This delayed response from the framework will in turn hinder the networks' ability to respond to the broader market changes to their financial detriment and that of energy consumers.

A recent ENA Discussion Paper[84] summarised the following areas of Australia's national energy regulatory framework that may impede networks' innovative behaviours, investments and practices:

- **The regulatory approval process:** regulators are unlikely to approve expenditure on cutting-edge technology given the inherently uncertain nature of innovation initiatives;
  - standard efficiency and prudence tests have been designed to favour projects and programs with clearly identified needs and solutions that provide a high degree of certainty regarding future network service delivery, rather than new and innovative initiatives.
- **Risk-reward ratio**: the framework provides an inadequate incentive for equity holders to invest in innovation because of the mismatch between the higher risk profile of innovative projects and the regulated rate of return.

84 Energy Networks Australia (2017). Network Innovation: Discussion Paper, July, pp 10-11.

- **Weak incentives for dynamic efficiency**: the framework is primarily focussed on operational efficiencies and cost containment (i.e. static efficiency), which is not sufficiently dynamic to suit the rapidly changing energy market.
- **Short-term focus**: the length of the current regulatory period is too short to fully realise the benefits of innovation activities, which require sustained effort across regulatory periods, including to respond to broader energy market developments.

Reflecting these concerns, the 2017 Finkel Review[85] recommended closer alignment of regulatory and market frameworks to support network innovation efforts and, ultimately, put innovative technologies to work.

### 17.5.2 Existing incentive schemes

The NGR allow for an access arrangement to include one or more incentive mechanisms to encourage efficiency in the provision of services.[86] These schemes are in addition to the inherent incentives that are embedded in the regulatory framework and the price cap tariff variation mechanism.

These schemes include the efficiency benefits sharing scheme (EBSS), the capex efficiency sharing scheme (CESS), and the service target performance incentive scheme (STPIS). Electricity network businesses also have access to a demand management incentive scheme (DMIS) under the National Electricity Rules.

These schemes are primarily focussed on providing financial rewards for cost containment and efficiencies achieved relating to the provision of core network services. Except for the DMIS, genuinely innovative projects that could potentially deliver long-term benefits to energy consumers will not be incentivised under these schemes.

### 17.5.3 International approaches

It is instructive to contrast the current Australian situation with how network regulatory frameworks internationally have been changing in response to rapidly evolving energy markets.

Network innovation schemes introduced in the UK in recent years are now quite mature, particularly the gas network innovation scheme introduced by OFGEM and comparable schemes introduced by other UK energy regulators (e.g. in Northern Ireland and Scotland).

There are other network innovation schemes established under regulatory frameworks in Europe and the US, including:

- Italian Regulatory Authority for Electricity Gas and Water
- California Public Utilities Commission
- New York State Energy Research and Development Authority.

In comparing regulatory innovation initiatives in other countries, it is important to distinguish between the source and size of funding made available. Some initiatives are large government and taxpayer funded schemes with specified broad energy policy or environmental goals, while others are smaller ongoing schemes funded through regulated revenues and with generally a narrower focus on network service innovation. The NIS proposed in this report is more in keeping with the small-scale innovation schemes observed overseas.

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85 Finkel, A (2017). Independent Review into the Future Security of the National Electricity Market: Blueprint for future. Published by the Department of Environment and Energy, June 2017, p 66.

86 Rule 98 of the National Gas Rules.

### 17.5.4 Previous 'network innovation scheme' proposals

The AER rejected a network innovation scheme proposed by Australian Gas Networks (AGN) in its 2018-22 Access Arrangement for the Albury and Victorian gas distribution network.

In rejecting the scheme proposed by AGN, the AER indicated it did not consider the scheme would (on balance) encourage efficiency in the provision of services in the long-term interests of gas consumers.[87] The AER concluded that:

- consumers bear the cost of investment and therefore take 100 per cent of the risk that the innovation project will fail;
- it is not clear how the benefits of the innovation projects will be shared between AGN and its customers; and
- the proposed network innovation scheme is not targeted at a specific social problem (such as emissions reduction).

The AER ultimately concluded that the current regulatory framework provides sufficient opportunity to invest in innovation while allowing businesses to retain any efficiency benefits, particularly with the addition of a capex efficiency sharing scheme (CESS)[88] to AGN's access arrangement. In our submission, this conclusion does not take account of the fact the CESS is primarily focussed on single regulatory periods and is focussed on shorter term efficiency rather than longer term innovation.

We also consider that the AER did not place sufficient emphasis on the fact the innovation scheme allowed it to assess projects on a case by case basis; the scheme is not an open-ended approval to spend $1 million per year as the regulated business must justify each project it undertakes.

We submit that the view taken by the AER doesn't address the fundamental challenge with truly innovative projects, which is that they have a high degree of uncertainty but also potentially offer significant future benefits to energy consumers. Hence, the future sharing of benefits from innovation cannot be precisely identified today.

Indeed, it would be unreasonable to consider that there will be no future benefit to consumers, given evidence from innovation activity that occurs economy-wide across unregulated product and services markets. Unfortunately, reliance on schemes such as the CESS, will not address the innovative challenge for regulated energy network businesses. This does not appear to be an outcome that promotes the long-term interests of customers considering the significant technological changes currently and prospectively affecting Australia's energy services market.

The NIS proposed in this 2020-24 Plan takes account of AER's conclusions relating to the design of AGN's scheme.

[87] AER (2017), Australian Gas Networks Victoria and Albury gas access arrangement 2018 to 2022, Attachment 14 – Other incentive schemes, Draft Decision, November, pp 13-16.

[88] A CESS encourages efficiencies through improvements in capex. It is primarily focussed on providing financial rewards to networks for achieving cost containment derived from capital efficiencies within a single regulatory period, rather than incentivising innovative projects that could potentially deliver benefits over multiple regulatory periods.

## 17.6 Innovation goals

### 17.6.1 Overview

We have identified four high-level innovation goals that could be targeted through innovation projects such that alternative funding mechanisms under the current regulatory framework may be warranted. These innovation goals are:

- Long-term efficiency improvements: focussed on exploiting opportunities to improve the efficiency of network services over the long-term.
- Zero-emission gas readiness: Focussed on ensuring that the gas distribution system is ready to receive, transport, deliver, monitor, and meter alternative gases like hydrogen for the long-term benefit of gas consumers.
- Making gas a stronger complement to electricity network services: Focussed on positioning the GDS to be a compelling complement to electricity services.
- Tracking and understanding transformative ICT opportunities: Focussed on identifying and understanding transformative information and communications technology opportunities that will help the business to maximise efficiency through timely and well-informed adoption.

### 17.6.2 Example innovation goal: Zero-emission gas readiness

Hydrogen is anticipated to be important in Australia's future energy mix both as a replacement for natural gas and as a means of storing the energy captured by intermittent wind and solar generators.

If the opportunity is well managed, there is significant scope to invest in our network to supply new and existing gas customers with a gas conveyance and capacity service that supplies hydrogen rather than natural gas. Taking early steps to ready the network to achieve this change is in the long-term interests of gas customers, since the cost of deriving energy from carbon intensive sources is likely to rise rapidly in the future. Meeting customers future energy needs at the lowest cost may, therefore, require us to offer conveyance services for a zero-emission energy source like hydrogen.

#### *17.6.2.1 Challenges and uncertainties*

Hydrogen presents specific chemical, engineering, and social challenges if it is to be successfully introduced into the GDS.

For example, in many applications, it requires PE pipes to be safely and efficiently conveyed. Hydrogen would initially need to be mixed with natural gas, and this blending would change the composition of the product delivered to customers, with composition differing depending on the network location. Further, hydrogen has different chemical characteristics that give rise to differences in odour management (an issue for network operation), and flame visibility and speed (an issue for customer appliances).

These technical challenges are currently being studied and overcome in academic settings, but more work is required to produce protocols, systems, and equipment ready for deployment.

The timing, scope and scale of the hydrogen opportunity are uncertain, but will be informed by technology advances, relative energy cost differentials (see above), and energy policy settings (e.g. the cost of carbon - whether priced explicitly or in shadow form).

However, if we do nothing to prepare for the possible introduction of hydrogen into the distribution network, there is a material risk of *asset stranding* that is inconsistent with the actions of a prudent network service provider. Further, it would appear to be inconsistent with the overarching Revenue and

Pricing Principles of the NGL, which provide that regard should be had to the economic costs and risks of the potential for under and over utilisation of a pipeline that provides regulated pipeline services.

#### *17.6.2.2 Relevance to gas customers*

Assuming the cost of carbon will rise over time, gas customers could reasonably be expected at some point to demand a low carbon gas option (hydrogen or biogas). Hydrogen-readiness of the GDS will directly address a broader energy market-driven customer requirement.

As the importance of gas as a balancing fuel and a source of bulk energy storage in electricity increases, if we can supply hydrogen using our network, this will facilitate greater network utilisation and indirectly assist customers by placing downward pressure on unit costs and consequently network service prices.

#### *17.6.2.3 Prudent investment*

A small to moderate level of expenditure on hydrogen trials represents the actions of a prudent network service provider; anticipating how future gas network services may need to change to meet a changing energy market circumstances and gas consumer demand.

### 17.6.3 Project tools

Reflecting the uncertainties associated with pursuing innovation goals and opportunities, there will be some small project tools that we will use assess feasibility. To this end, we expect the proposed NIS could potentially fund:

- Pre-feasibility studies
- Desktop technology and market opportunity assessments
- Feasibility assessments
- Engineering studies
- Service and business model development
- Market research
- Field trials and demonstration projects

We intend that our proposed NIS would provide a small level of funding for any of these types of tools. In this way, we envisage the NIS supporting several small-scale activities that will support ongoing innovation in our network service provision.

Ultimately, expenditure may be required for a specific innovation-related project that must be assessed under the standard capex or opex tests because of its size and greater certainty of future benefits. The NIS is intended to provide a small level of funding over time to enable a specific innovation-related project to be developed to the stage where it reaches the stricter expenditure assessment level.

## 17.7 Proposed Network Innovation Scheme

### 17.7.1 Overview

The proposed NIS included in this 2020-24 Plan has been developed having regard to the NGO and the Revenue and Pricing Principles in the NGL (as required under Rule 98 of the NGR) by:

- encouraging ATCO to undertake long-term research and R&D trials or projects that may not otherwise occur and that are likely to be in the long-term interest of Western Australian gas consumers, including through more cost-effective future network investments;

- removing barriers to innovation through facilitating solutions that are likely to improve long-term safety, reliability and security of gas supply; and
- ensuring that current gas network customers bear only a small risk regarding the conduct of innovation trial projects, recognising the higher degree of uncertainty regarding the future benefits of these projects compared to conventional network investment projects.

We consider that the NIS design features meet these criteria.

### 17.7.2 Scheme objective

Given the proposed NIS is not a defined incentive scheme under the NGR, it is useful to clearly state its purpose and link it to the NGO and Revenue and Pricing Principles as follows:

> *The objective of the NIS is to provide ATCO Gas Australia with funding for projects using innovative and new technologies with the potential to deliver medium to long-term improvements in Pipeline Services that are in the long-term interests of consumers of natural gas in Western Australia*.

The objective makes explicit that projects must demonstrate the potential for medium to long-term benefits – that is, over timeframes beyond a single regulatory period.

Establishing an overarching objective for specific incentive schemes or regulatory instruments is a good regulatory design feature of Australia's national energy regulatory framework, which we have adopted. The NER also establishes a similar overarching objective for the AER's DMIA scheme.[89]

### 17.7.3 Project eligibility criteria

To provide confidence that the only projects, trials, or activities that should receive funding under the NIS are those that satisfy the scheme's objective, we consider tight project eligibility criteria are required. Hence, under our regulatory scheme design, we will only seek NIS funding for innovation projects that satisfy the following criteria:

- It is a project or program for researching, trialling, developing, or implementing a piece of new equipment, a new arrangement or application of existing network infrastructure, or a new practice directly relating to:
  - an improvement in the operation or safety of the network; or
  - an improvement in customer service; or
  - a new business or revenue model, or
  - a reduction to the carbon intensity of the gas distributed by the network; and
- it is innovative, in that the project or program:
  - is based on new, novel, or original concepts and involves technology or techniques that differ from those used on a commercial scale in the Western Australian natural gas market; or
  - facilitates the adoption of new technologies that can expand the existing range of uses for gas or the gas network; and
  - has the potential, if proved viable, to reduce long-term network costs and prices or improve the quality of network services; and
- the potential benefit to gas network customers is material, considering the scale of innovation funding proposed and the level of uncertainty associated with the project or program.

89 National Electricity Rules, Part 6, Section 6.6.3A(b).

In applying the eligibility criteria, it is important to distinguish between the *purpose of a specific project* (which we consider should always have an innovation focus), and the project tools (e.g. trials, research, surveying) that are not inherently innovative but rather serve the broader innovation goal or purpose.

### 17.7.4 Scheme administration

We envisage the NIS being administered by the ERA on an annual basis in AA5 and beyond, including checks and balances to ensure existing gas consumers only pay for approved trials and projects.

The administrative features we have identified for the NIS are consistent with the NIS objective and will provide certainty to ATCO and the ERA about how the scheme will operate. More broadly, this should facilitate the effectiveness of the NIS and ensure its consistency with the achievement of the NGO and Revenue and Pricing Principles in the NGL.

Main administrative features of the NIS are as follows:

- An annual cap of $1 million (CPI indexed each year to maintain its value in real terms) will be set to limit how much we can spend on innovative trials and projects that satisfy the eligibility criteria under the scheme.
    - We propose an annual cap of this size to ensure that we have sufficient funding to undertake meaningful trials and projects without imposing an unreasonable burden on existing gas consumers.
    - A funding envelope of this size is also consistent with the AER's DMIA.
- Each year, we will seek ex-post recovery of actual costs that we have incurred in that year under the scheme through the annual tariff variation mechanism.
    - This approach ensures that our customers will only pay for incurred costs on eligible innovative projects each year (with a one-year lag in our cost recovery).
- Each year of the regulatory period, we can apply to the ERA for an upfront, indicative approval for planned expenditure under this NIS.
    - There is no requirement for us to identify at the start of each regulatory period the suite of trials and projects that we intend to undertake over the full regulatory period. This maintains our flexibility to respond to changing market circumstances.
- Eligible projects can be funded across regulatory years and periods provided the total NIS allowance is not exceeded in any access arrangement period.
- To avoid 'double dipping' of funding for the same projects, the NIS allowance should only provide funding for projects that have not been funded previously from another source (e.g. ARENA grants, ERA's access arrangement determination).
- The ERA should review the size of the NIS allowance as part of each access arrangement determination.

### 17.7.5 Compliance reporting

Annual compliance reporting under the NIS will ensure that the ERA can assess our compliance with the scheme's administrative details and, more broadly, the scheme's objective.

The main compliance reporting requirements are as follows:

- ATCO must submit to the ERA, annual reports on its activities, expenditures, and projects undertaken under the scheme;
- The ERA will conduct ex-post reviews of our trials and projects to determine their compliance with the project eligibility criteria, which will determine our eligibility to receive funding for the specific trial or project under the scheme;

- ATCO will periodically advise the ERA on whether the projects and trials we have undertaken remain likely to be in the long-term interests of WA gas consumers, including what we have learnt and how this has been applied within the business; and
- ATCO's annual compliance report is to be supported by a certification that the report is accurate and complete.

These reporting requirements are intended to provide confidence to the ERA and Western Australian gas consumers about the effectiveness of the NIS and specifically that its objective is being met.

## 17.8 The Network Innovation Scheme in practice

To test the robustness of our proposed NIS assessment criteria, such that any projects that are not genuinely innovative will be rejected, we have applied these criteria to a sample of innovative projects that we are currently investigating. Table 17.2 presents a summary of the outcomes of our preliminary high-level assessments.

**Table 17.2:** Sample innovation projects and compatibility with the Network Innovation Scheme

| INNOVATION GOAL AND PROJECT | DESCRIPTION | PRELIMINARY HIGH-LEVEL ASSESSMENT |
|---|---|---|
| 1. Zero-emission readiness: distribution equipment specification and operation | Ensure the suitability of distribution equipment for a system conveying varying proportions of hydrogen. | ✓<br>Project incorporates new, novel, or original concepts and involves technology or techniques that differ from those previously implemented or used in the Western Australian Energy Market. |
| 2. Zero-emission readiness: measurement of energy delivery | Determine a system for accurately measuring delivered energy in a system with a disparate and dynamic hydrogen-methane blend. | ✓<br>Project incorporates new, novel, or original concepts and involves technology or techniques that differ from those previously implemented or used in the Western Australian Energy Market. |
| 3. Zero-emission readiness: customer acceptance | Test the workability of introducing zero-emission fuels into the network by testing customers' receptiveness, including identifying technical or social pre-requisites for acceptance. | ✓<br>Supports the broader zero-emission readiness goal, which in turn incorporates new, novel, or original concepts and involves technology or techniques that differ from those previously implemented or used in the Western Australian Energy Market. |
| 4. Long-term efficiency reforms: asset management and maintenance | Reduce costs though speculative investigations into alternative asset management and maintenance approaches. | ✓<br>Illustration project incorporates novel or original concepts and involves technology or techniques that differ from those previously implemented or used in the Western Australian Energy Market. |

| INNOVATION GOAL AND PROJECT | DESCRIPTION | PRELIMINARY HIGH-LEVEL ASSESSMENT |
| --- | --- | --- |
| 5. Long-term efficiency reforms: metering innovation | Reduce costs and improve services with yet-to-be demonstrated metering technologies and service models. | ✗<br>The scale of currently known opportunities is insufficient to justify funding innovation projects. |
| 6. Long-term efficiency reforms: Virtual gas pipeline | Reduce costs by substituting virtual gas pipelines instead of possible network extensions. | ✗<br>These services are supplied using unregulated assets and hence are beyond the scope of the NIS. |
| 7. Electricity complementarity: Promote gas solutions to electricity problems | Increase gas demand by promoting customer engagement, understanding and acceptance of new appliances and solutions at the interface between the gas and electricity markets. | ✗<br>Extends to potentially contestable services supplied using unregulated assets and hence beyond the scope of the NIS. |
| 8. Track and understand transformative IT opportunities: Artificial Intelligence | Investigate and trial artificial intelligence applications to understand opportunities for deployment within the business to reduce costs and improve productivity. | ✓<br>Project incorporates new, novel, or original concepts and involves technology or techniques that differ from those previously implemented or used in the Western Australian Energy Market. |

# 18. Total revenue

**CHAPTER HIGHLIGHTS**

1. We applied the building block method on a post-tax basis to determine the total revenue in AA5.
2. The building block revenue requirement for AA5 is calculated to be $1,025 million, which compares with $922 million over the five and a half years of AA4.

## 18.1 Introduction

We have applied the building block method on a post-tax basis to determine the total revenue required in AA5 for the provision of reference services. The building block method is commonly used in regulatory determinations and is required by Rule 76.

'Total revenue' consists of 'building blocks' that are summed to determine total revenue in each year of AA5. These building blocks include the return on capital, depreciation, opex, and other components such as taxes and incentive mechanisms. We recover the total revenue through tariffs for the provision of reference services on a net present value equivalent basis.

Table 18.1 provides cross-references to the sections of this document that discuss and justify our proposal for each of the building blocks.

**Table 18.1:** Cross-references to building block information in this document

| REVENUE BUILDING BLOCK | SECTION OF THIS DOCUMENT |
|---|---|
| Return on the projected capital base | Section 13.5 and Chapter 14 |
| Return of the projected capital base | Section 13.6.2 |
| Return on working capital | Chapter 14 and Chapter 16 |
| Estimated cost of corporate income tax | Chapter 15 |
| Forecast opex | Chapter 11 |

This chapter sets out the total revenue for AA5.

## 18.2 Stakeholder engagement

We published our 2020-24 Draft Plan at the beginning of May 2018 and invited feedback from stakeholders. Several retailers and other parties provided feedback. The feedback relevant to total revenue is summarised in Table 18.2.

**Table 18.2:** Stakeholder feedback – Total revenue

| DRAFT PLAN STAKEHOLDER QUESTION | STAKEHOLDER FEEDBACK | OUR RESPONSE TO FEEDBACK ON OUR DRAFT PLAN |
|---|---|---|
| Do you consider our calculations for revenue to be reasonable?<br>Do you have any comments on the methods we have used in our calculations? Do you believe they are fair and reasonable? | There was a general response pointing out the ERA's obligation to review the method of calculating total revenue and its value. | **No change** to our Draft Plan method. |

## 18.3 Regulatory framework

The NGR prescribe the approach for calculating the total revenue for our access arrangement. The main governing rules associated with our total revenue calculations are:

- **Rule 76**: Total revenue. Rule 76 sets out the building block components that make up total revenue.

Other rules to be considered in relation to the total revenue are:

- Rule 87A: Cost of corporate income tax
- Rule 92: Revenue equalisation

## 18.4 Building block total revenue

The forecast total building block revenue for the provision of reference services over AA5 is $1,025 million comprised of the building blocks shown for each year in Table 18.3.

**Table 18.3:** Total revenue ($M nominal)

| BUILDING BLOCK | 2020 | 2021 | 2022 | 2023 | 2024 | TOTAL |
|---|---|---|---|---|---|---|
| Forecast opex | 68.8 | 71.8 | 76.1 | 79.3 | 82.0 | **377.9** |
| Return of the projected capital base | 49.4 | 60.5 | 63.9 | 67.0 | 70.9 | **311.7** |
| *Less* inflationary gain in return on assets | -24.8 | -26.3 | -27.6 | -28.9 | -30.2 | **-137.8** |
| Return on the projected capital base | 81.2 | 86.1 | 90.4 | 94.6 | 99.0 | **451.4** |
| Return on working capital | 0.1 | 1.5 | 1.5 | 1.6 | 1.6 | **6.3** |
| Tax payable | 6.7 | 5.5 | 4.5 | 4.0 | 3.4 | **24.1** |
| *Less* value of imputation credits | -2.3 | -1.9 | -1.5 | -1.4 | -1.2 | **-8.2** |
| **TOTAL REVENUE (UNSMOOTHED)** | **179.2** | **197.3** | **207.3** | **216.2** | **225.5** | **1025.5** |

The total revenue requirement is collected on an NPV equivalent basis through the reference tariffs, as per the requirements of Rule 92. Our approach to revenue equalisation through the reference tariffs is described in Chapters 19 and 20.

# PART C:

## Derivation of Reference Tariffs

# 19. Reference tariffs

**CHAPTER HIGHLIGHTS**

1. Our proposed price path for AA5 promotes efficient price signals and enhanced price stability by aligning our *cost of service* with our *expected tariff revenue* over AA5. We are seeking to achieve this by:
   a) Proposing a 22.2% increase in tariffs for tariff classes A1, A2, B1, and B2 on 1 January 2020, followed by annual 2.3% real increases in each of the following years.
   b) Following increases in the B3 tariff class fixed charge over AA4, we propose to hold the B3 fixed charge at the 2019 level in real terms over AA5.
   c) Following significant decreases in the B3 tariff class variable charges over AA4, we propose to increase the variable charges on 1 January 2020 to a similar level to the 2017 prices in real terms followed by annual 2.3% real increases in each of the following years.
2. We have proactively engaged with customers and stakeholders (including Retailers) on the distribution charge profile over AA5 to provide an early indication of the expected network tariff movements and avoid any surprises or price shock.
3. The average annual distribution charges over AA5 (based on average consumption in AA5) will be at similar, or lower levels, in real terms compared to the average annual distribution charge in AA4.

## 19.1 Chapter summary

### 19.1.1 Background and context of our proposed Reference Tariffs

The price path over AA4 has led to our expected tariff revenue being lower than our cost of service. The AA4 Final Decision resulted in our 2019 forecast tariff revenue to be *$38 million lower* than the forecast cost of service. The 2019 tariff levels are not sustainable into AA5 and price increases are necessary to allow the cost of service to be recovered.

The objective of the NGL is to "… *promote efficient investment in, and efficient operation and use of, natural gas services for the long-term interests of consumers of natural gas…*"[90]. Any misalignment between the cost of service and expected tariff revenue creates price signals that lead to inefficient network investment and inefficient network utilisation.

During our consultation with Retailers (see Chapter 4), they expressed a strong preference for setting a 'smooth' price path, one that included a steady and consistent increase from 2019 price levels for each year of AA5. Based on our Retailers' feedback, we have moderated the initial price increase; however, a full adoption of this 'steady and consistent increase' approach is not proposed due to a couple of important reasons.

Firstly, for our business to recover the cost of service over AA5, we would have to *under recover* revenue at the start of AA5, then *over recover* at the end of AA5. To rectify this in the following access arrangement (AA6), we would have to take the same approach in *reverse: over-recovering* at the start of the AA6 period, then *under-recovering* at the end of the AA6. Either situation does not support the NGO due to the inefficient price signals created.

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[90] National Gas Access Act (2009), Section 23

Secondly, our customers would be experiencing increasing prices for five years (in AA5), followed by decreasing prices for the next five years (in AA6). The strong preference for price stability of many of our customers was a significant finding in our VoC engagement; a steady and consistent increase in distribution charges from 2019 through the five years of AA5 does not accomplish this stability, and neither does the potential and subsequent pattern of decreasing prices in AA6.

> This continued 'see-sawing' of prices is what we are attempting to rectify with our suggested price path for AA5 – an initial price adjustment from 2019, followed by a marginal increase in the years following.

This continued 'see-sawing' of prices is what we are attempting to rectify with our suggested price path for AA5 – an initial price adjustment in 2020, followed by a marginal increase in the years following. This is good for promoting efficient utilisation and investment in our network and good for our customers (as played out in our VoC program).

The 'one-off' price adjustment to tariffs at the beginning of AA5:

- Allows price signals that promote efficient utilisation and investment in the network to be implemented sooner rather than later.
- Promotes stable prices within an access arrangement period.
- Minimises the potential for "price shock" across access arrangement periods because in 2024, tariff revenue approximates the cost of service.

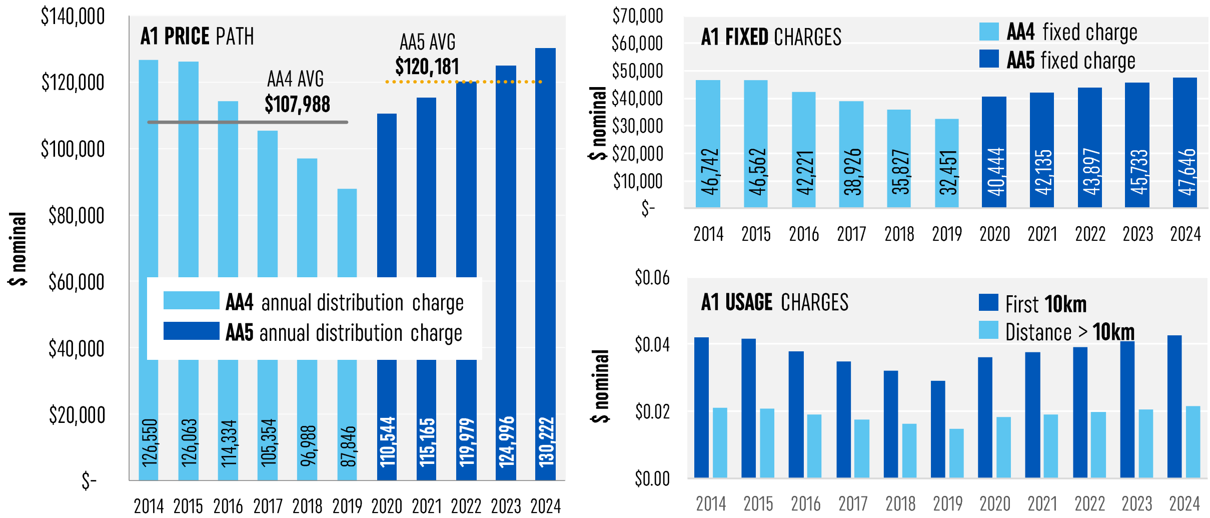
In addition, the National Gas Access (WA) (Local Provisions) Regulations 2009 requires that the effect on small-use customers and retailers must be considered. These considerations are:

- **Small-use customers:** Use of a price path that promotes price stability is supported by the outcome of our VoC program where small use customers generally preferred price stability over annual increases. Additionally, we have constructed tariffs so that for customers (at average consumption), the average distribution charge increase is either *below or within 1%* of inflation. The B3 tariff class standing charge has been held at the 2019 level in real terms to promote utilisation of the network and the sharing of fixed costs over a larger customer base to the benefit of all customers. The fixed charge after increases in AA4 is now at a level where the fixed costs of a new connection are recovered even if no consumption is used. Therefore, the fixed charge will not be increased further (in real terms).
- **Retailers:** Retailer concerns regarding the proposed amount of the initial price increase in 2020 have been heard. Consequently, we have moderated the initial price increase by an annual real price increase of 2.3%, except for the B3 tariff class standing charge. 2.3% was the maximum annual price increase possible while keeping 2024 cost of service within 3% of expected tariff revenue (the guideline set by the AER[91]). We have also kept tariffs at lower than 2016 levels in nominal terms so that gazetted retail tariffs should be sufficient to cover any tariff increases in 2020.

91 In its July 2017 draft decision on Australian Gas Networks (Victoria and Albury gas distribution network access arrangement, 2018-2022), the AER at page 28 noted its target range of 3% for the divergence of expected tariff revenue and forecast cost of service in the final year of the access arrangement period. The target range aims to minimise price variance between access arrangement periods.

## 19.1.2 Summary of reference tariff changes between AA4 and AA5.

**Figure 19.1:** A1 customer reference tariff changes (AA4 to AA5)




### A1 PRICE PATH

The annual average **distribution charge** increase (for an average consumption customer) is maintained close to the level of inflation, while aligning our cost to service with our expected tariff revenue.

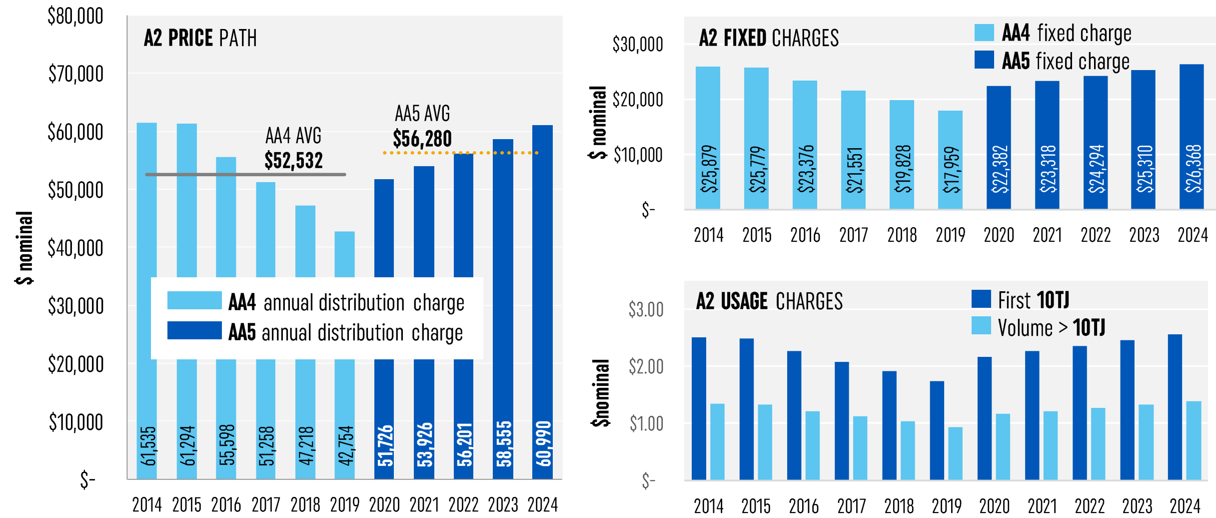
### A1 FIXED & USAGE CHARGES

**Fixed charges** have been increased to align cost to serve and expected tariff revenue. Usage charges have been set to reflect cost to provide capacity, and maintain price signals for efficiency.

### A1 MARGINAL USAGE CHARGES

**Marginal usage charges** are set to consider our long-run marginal cost, including the length of pipeline required. Declining block tariffs are set to encourage greater utilisation of the network.

**Figure 19.2:** A2 customer reference tariff changes (AA4 to AA5)




### A2 PRICE PATH

Annual **distribution charge** increase at average consumption maintained close to level of inflation while aligning cost to service with expected tariff revenue.

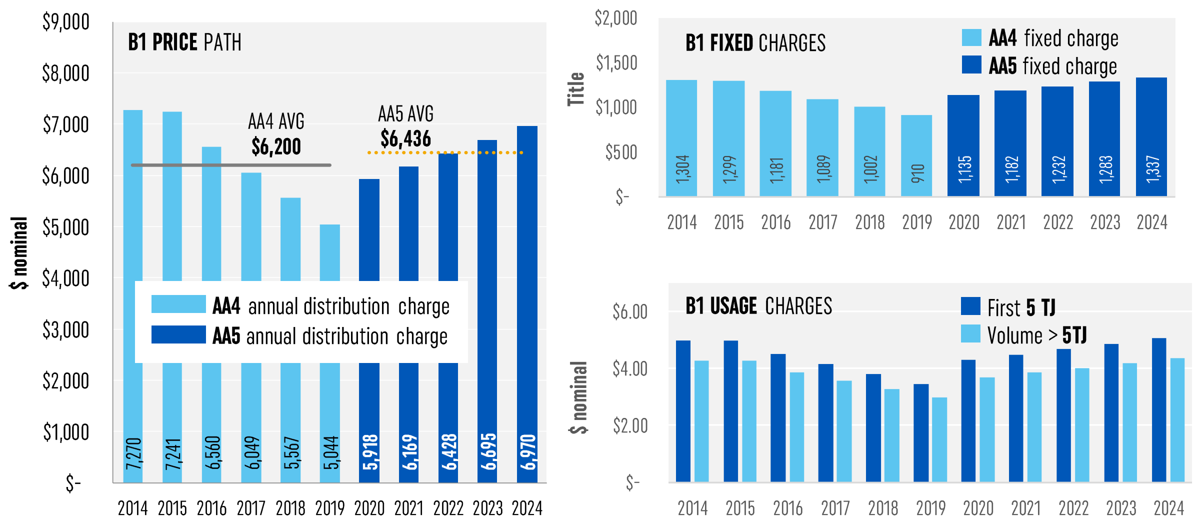
### A2 FIXED & USAGE CHARGES

**Fixed charges** have been increased to align cost to serve and expected tariff revenue.

### A2 MARGINAL USAGE CHARGES

**Marginal usage charges** consider long run marginal cost. Declining block tariff to encourage utilisation of network. First usage tariff band contributes to recovery of residual costs

**Figure 19.3:** B1 customer reference tariff changes (AA4 to AA5)




### B1 PRICE PATH

Annual **distribution charge** increase at average consumption maintained close to level of inflation while aligning cost to service with expected tariff revenue.

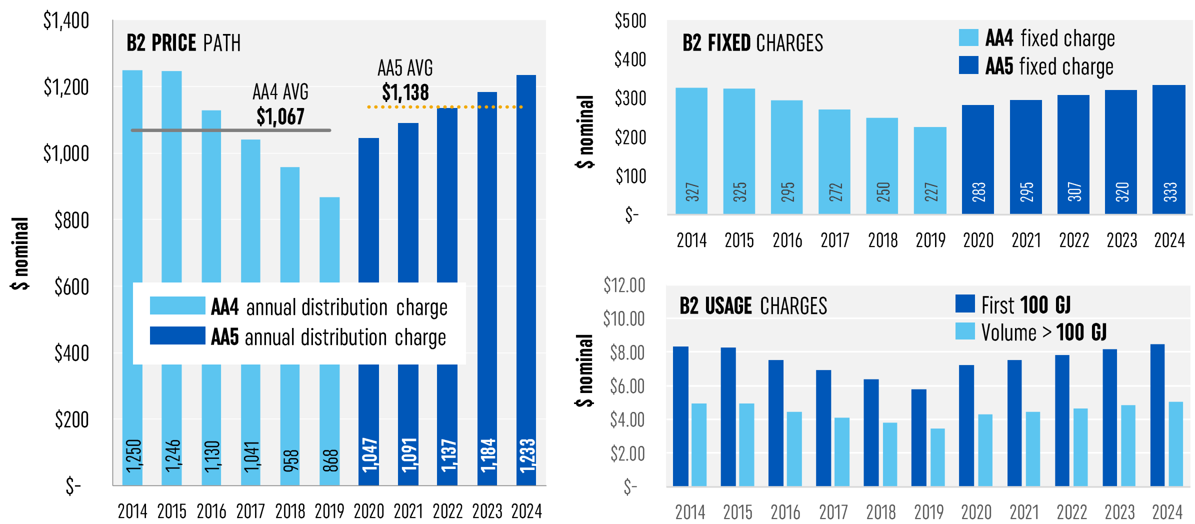
### B1 FIXED & USAGE CHARGES

**Fixed charges** have been increased to align cost to serve and expected tariff revenue.

### B1 MARGINAL USAGE CHARGES

**Marginal usage charges** consider long run marginal cost. Declining block tariff to encourage utilisation of network. First usage tariff band contributes to recovery of residual costs

**Figure 19.4:** B2 customer reference tariff changes (AA4 to AA5)




### B2 PRICE PATH

Annual **distribution charge** increase at average consumption maintained close to level of inflation while aligning cost to service with expected tariff revenue.

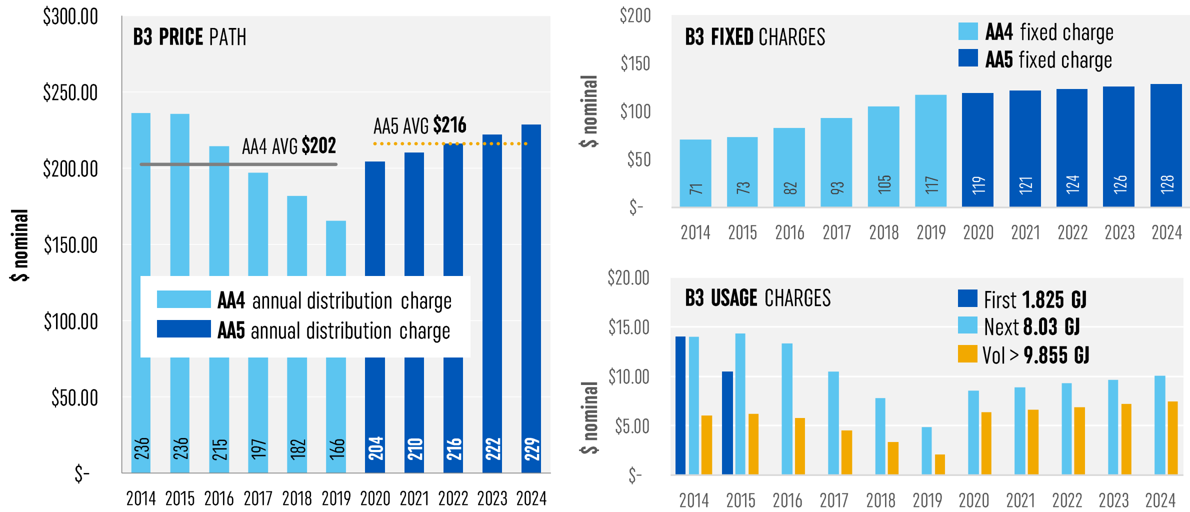
### B2 FIXED & USAGE CHARGES

**Fixed charges** have been increased to align cost to serve and expected tariff revenue.

### B2 MARGINAL USAGE CHARGES

**Marginal usage charges** consider long run marginal cost. Declining block tariff to encourage utilisation of network. First usage tariff band contributes to recovery of residual costs

**Figure 19.5:** B3 (residential) customer reference tariff changes (AA4 to AA5)




**B3 PRICE PATH**

Annual **distribution charge** increase at average consumption maintained close to level of inflation while aligning cost to service with expected tariff revenue.

**B3 FIXED & USAGE CHARGES**

**Fixed charges** held at 2019 real dollars as it reflects fixed costs per connection after increase during AA4 Standing charges are sufficient to recover residual costs.

**B3 MARGINAL USAGE CHARGES**

**Marginal usage charges** consider the long-run marginal cost. Declining block tariffs encourage utilisation of the network. The zero-charge for the first 1.825 GJ is maintained to encourage connection and spread fixed costs over a larger customer base to the benefit of all customers.

## 19.2 Introduction

This chapter sets out:

- Our objectives, and the reasons for those objectives, when setting tariff structures.
- Our process for setting tariff classes, tariff structures, and tariffs.
- Our proposed tariff structure and tariffs.

Our main considerations when setting tariff structures and tariffs, were to ensure economically efficient price signals, legislative compliance, and to balance the competing preferences of customers and retailers; respectively 'long-term price *stability'*, compared with 'a steady and consistent price increase across the years of AA5'.

## 19.3 Stakeholder engagement

As discussed in Chapter 4, we commenced our customer and stakeholder engagement back in December 2016, with several workshops with gas consumers to discuss our plans and activities for the coming years. This early engagement provided the foundation for our VoC program that commenced in 2017.

We have proactively engaged with customers and stakeholders (including Retailers) on the distribution charge profile over AA5 to provide an early indication of the expected network tariff movements, and to avoid any surprises or price shocks.

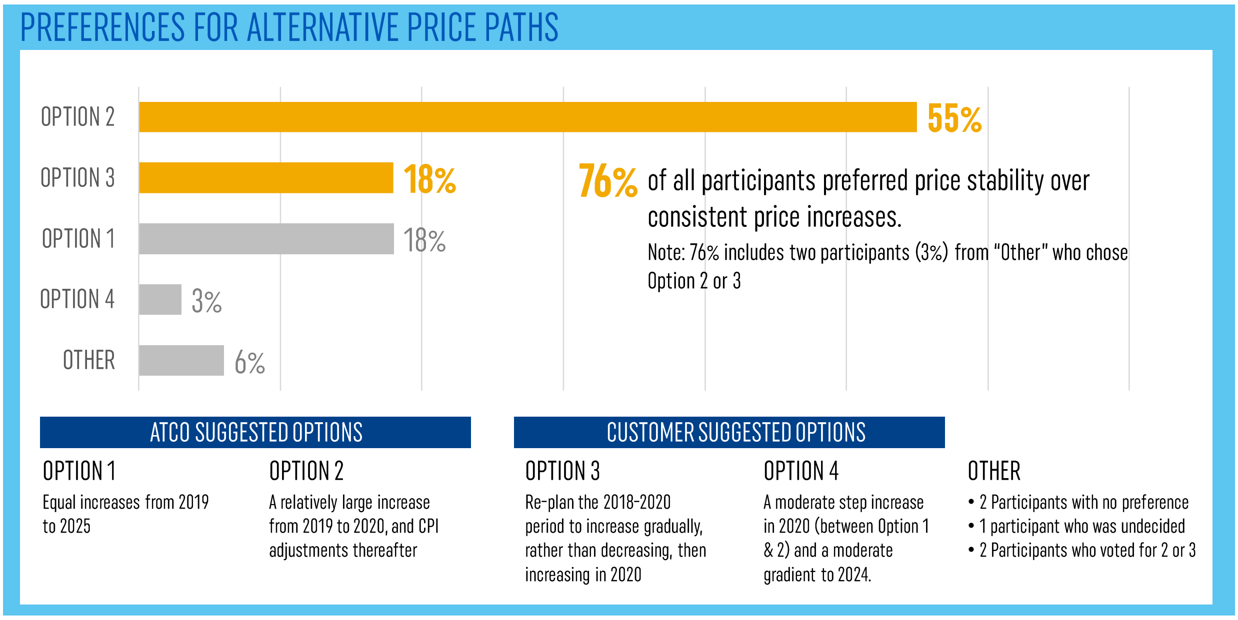
We have proactively engaged with customers and stakeholders (including Retailers) on the distribution charge profile over AA5 in order to **provide early indication of the expected network tariff movements so as to avoid any surprises or price shock**.

Our pricing for AA5 was an important topic of discussion in the Engage Phase of our VoC program. We presented our customers with the potential price increases for the distribution component of their bill for the next period, explaining that the increases were based on proposed capital works programs for AA5. Both residential and SME workshop participants considered the price increase for AA5 as modest given the projects being considered.

We then sought customers' views on *how* the price increase should be introduced in AA5. Through a worksheet activity, customers were asked for their preferences on the size of an upfront increase, and subsequent percentage increases in the remaining years of the period.

Most customers (76% overall, with 86% for residential, 74% for SME and 25% for C&I customers) chose a *stable price path* as their preference for paying for the increase in costs (Option 2 in Figure 19.6). Customers accepted the larger increase in the initial year as they viewed the step change as modest.

**Figure 19.6:** Customer preferences for various price path options




Subsequently, we published our 2020-24 Draft Plan in May 2018. Table 19.1 details feedback from stakeholders regarding our 2020-24 Draft Plan, and our respective response.

**Table 19.1:** Consideration of stakeholder feedback on reference tariffs

| DRAFT PLAN STAKEHOLDER QUESTION | STAKEHOLDER FEEDBACK | OUR RESPONSE TO FEEDBACK ON OUR DRAFT PLAN |
|---|---|---|
| Do you support our Voice of Customer findings that an initial price step-up, followed by longer-term price stability is preferred over consistent increases over AA5?<br>What are the possible effects of the proposed reference tariffs, the method of determining the tariffs and the | **Retailer B** supports a smaller initial price step in 2020 followed by consistent increases over AA5. Retailer B raised the issue of possibly not being able to pass through distribution charge increases greater than the currently regulated allowed increases in retail prices."<br>**Retailer A** would like to avoid a large single year increase in price in 2020, especially when changes in other components of the 2020 retail price are | **Change:** We have moderated the increase in distribution charges shown in the Draft Plan from 2019 to 2020 offset by increases in the following years.<br>Regarding Retailer B's concern about its ability to pass through distribution charge increases, the increase proposed brings tariffs broadly back to 2017 levels. We note that regulated retail tariffs have not declined in line with the declines in distribution charges |

| DRAFT PLAN STAKEHOLDER QUESTION | STAKEHOLDER FEEDBACK | OUR RESPONSE TO FEEDBACK ON OUR DRAFT PLAN |
|---|---|---|
| reference tariff variation mechanisms on retailers and customers? | unknown at this point in time. Consequently, Retailer A would prefer a price path in line with Option 1 or Option 4 in the ATCO plan. They accept a small step jump in price in 2020 but the 2020 increase derived from Option 2 is material." | from 2015 to 2019. Given the proposed tariffs do not exceed levels prior to 2016, the regulated retail tariff should be sufficient to cover any tariff increase (absent of increases in other retail costs greater than inflation). |
| Other: No gas consumption | **Retailer B** encourages ATCO to reconsider on-charging retailers the fixed network charge component where there has been no gas usage at a property for more than 12 consecutive months and instead work with retailers to encourage resumption of gas consumption | **No change –** We have considered this matter and found that there is no scope to implement this proposal. The service provided by ATCO to a zero-consumption meter is the same as if the meter has consumption. If the service is the same, then the distribution charge should be the same. We cannot discriminate among delivery points receiving the same service. We do however, welcome any opportunity to work with retailers to encourage the resumption of gas consumption. |
| Other: Cancellation charges | **Retailer A** and **Retailer D** raised the issue of tariffs for cancelled service orders and suggested a lower tariff for service orders cancelled up to two days before the date of the cancelled activity. | **No change –** We are investigating the potential for reduced fees for reference ancillary services. Preliminary estimates of capital costs for system changes are in the order of $50,000. However initial indications are that IT capital costs would outweigh the potential savings to retailers. Additional IT capital costs to implement the charging of a reduced fee would have to be included in the forecast capex program for AA5. We would like to work with retailers to reduce the number of cancelled services. |

In July 2018, following this feedback, we held a workshop with retailers regarding the proposed AA5 price path. Retailers again expressed a strong preference for a *smooth* price path over AA5 (Option 1 in Figure 19.6); a consistent increase in tariffs between 2019-2025. Retailer preferences were therefore inconsistent with the preferences of other stakeholders; the preference for an initial larger increase between 2019-2020 and a subsequent smaller annual increase between 2021-2025 (Option 2 in Figure 19.6).

To balance the needs of our stakeholders, and address these competing preferences, we have modified our proposed price path from the one outlined in our 2020-24 Draft Plan.

To balance the needs of our stakeholders, and address these competing preferences, we have modified our proposed price path from the one outlined in our 2020-24 Draft Plan. Our new price path includes a smaller initial step change in 2020 followed by above CPI increases during AA5. Proposed prices for each reference tariff class are outlined in Section 19.9.

## 19.4 Tariff objectives

Our main considerations when setting tariff structures and tariffs, were to ensure economically efficient price signals, legislative compliance, and to balance the competing preferences of customers and retailers; respectively 'long-term price *stability'*, compared with 'a steady and consistent price increase across the years of AA5'.

This section elaborates on the preference expressed by customers and retailers, our objectives in setting economically efficient price signals and the regulatory framework that underpins our legislative compliance requirements.

### 19.4.1 Customer and retailer preferences

We have sought to balance the competing views of customers and retailers on the overall price path:

- **Customers:** A strong preference of many of our customers was *stability* in pricing*;* that is, a step change in 2020 followed by stable distribution charges (Option 2 in Figure 19.6).
- **Retailers:** Feedback on the Draft Plan indicated a preference by retailers to smooth the transition from AA4 tariffs to AA5 tariffs with equal increases from 2019 to 2024 (Option 1 in Figure 19.6).

### 19.4.2 Economically efficient price signals

We have sought to provide economically efficient price signals by setting tariffs in a way that seeks to minimise:

- tariff variability *within* the access arrangement period; and
- tariff variability *between* access arrangement periods by setting the 2024 cost of service within 3% of the expected tariff revenue[92].

We have considered the need for tariffs to:

- reflect efficient costs to provide the service; and
- provide signals to promote efficient utilisation of, and investment in the network.

### 19.4.3 Regulatory framework

The NGL includes objectives and principles that influence our approach to setting reference tariffs. The associated NGR set out a process to establish tariff classes and the tariffs for those tariff classes. Meeting the objectives and compliance with the principles, processes and requirements of the legislation is a necessary consideration when setting tariffs.

In relation to the NGL, particular regard should be had to the NGO[93] and revenue and pricing principles[94].

Regarding setting tariffs, the revenue and pricing principles contained in sections 24(3), 24(6) and 24(7) of the NGL are relevant because they relate to the effect that tariffs can have on efficient investment in and utilisation of the network. These sections of the NGL are restated below.

*24 (3) A service provider should be provided with effective incentives in order to promote economic efficiency with respect to reference services the service provider provides.*

*The economic efficiency that should be promoted includes—*

92 This is consistent with the approach applied to other gas distribution networks by the Australian Energy Regulator

93 National Gas Access Act WA (2009), Section 23

94 National Gas Access Act WA (2009), Section 24

*(a) efficient investment in, or in connection with, a pipeline with which the service provider provides reference services; and*

*(b) the efficient provision of pipeline services; and*

*(c) the efficient use of the pipeline*

*24 (6) Regard should be had to the economic costs and risks of the potential for under and over investment by a service provider in a pipeline with which the service provider provides pipeline services.*

In summary what the revenue and pricing principles require is that *tariffs should reflect the costs of providing reference services and provide price signals that promote efficient investment in and utilisation of the network.*

The tests at rule 94 of the NGR put these principles into effect. The tests in the NGR include testing the expected tariff revenue, given the tariffs set, against the requirements that:

- for each tariff class the expected tariff revenue is between the avoidable cost and stand-alone cost of providing the reference service to that tariff class;
- in net present value terms, the total cost of service equals the expected tariff revenue; and
- the tariffs set consider the long run marginal cost of providing services.

In addition, the *National Gas Access (WA) (Local Provisions) Regulations 2009* requires that:

- the impact on small use customers and retailers must be taken into account; and
- uniform tariffs must be applied to small use customers for the same service irrespective of their location.

ATCO has sought the views of customers and retailers on the implications of our pricing through our VoC program and through the feedback received on the Draft Plan published in May 2018.

We have sought to balance the needs of small use customers and retailers against the requirement for economic efficiency contained in the NGL, as the two requirements may not always point to the same outcome.

## 19.5 Tariff setting process

The section summarises our process to set tariff classes, tariff structures, and tariff charging parameters. Our process is guided by the tariff objectives described in Section 19.4.

Our process to set the AA5 tariffs includes:

1. **Setting tariff classes:** Establishing the tariff classes for the reference services.
2. **Setting tariff structures:** Establishing the structure of each tariff for each tariff class
3. **Setting AA5 tariff charging parameters:** Determining the individual charging parameters for each of the elements of the tariffs.

Further detail on this process is in the following sections and Attachment 19.1.

## 19.6 AA5 tariff classes

We propose that the tariff classes in AA5 be the same as the tariff classes in AA4. We have sought to maintain the tariff classes because there are no material changes in the:

- types of haulage services required by customers in each tariff class; or
- types of customers requiring reference services.

In addition, customers and stakeholders have not raised any concerns with the tariff classes during the VoC program or in responses to the Draft Plan.

Our view is that the proposed tariff classes meet our regulatory obligations:

- **Economically efficient:** ATCO has a single tariff class for each reference service. Our reference services are defined by the type of delivery facilities that are provided to certain customer groups. Grouping customers according to the delivery facilities means that the required tariffs can be constructed to reflect the costs related to serving that tariff class and provide suitable price signals. Therefore, customers have been grouped on an *economically efficient basis* as required by NGR 94(2)(a).
- **Avoid unnecessary transaction costs:** Maintaining the same tariff classes reduces unnecessary transaction costs by avoiding changes to systems by both ATCO and Retailers. Therefore, the proposed tariff classes meet NGR 94(2)(b) as they avoid unnecessary transaction costs.

Maintaining the same tariff classes also contributes to the stability required by customers. Further detail on our tariff classes is provided in Chapter 19.

## 19.7 AA5 tariff structures

We propose that the tariff structures in AA5 be the same as the tariff structures in AA4 for both haulage and ancillary services. These are discussed in the sections below.

### 19.7.1 Tariff structure: *haulage services*

We will maintain the AA4 tariff structure for AA5. The basic tariff structure, including both a fixed charge and a declining block usage charge component, has been in place since January 2000; although there have been minor variations at access arrangement reviews.

Maintaining the AA4 tariff structure for AA5 supports the outcomes of the VoC program. We heard that customers value stability, therefore maintaining the existing tariff structure assists in keeping customers' prices relatively consistent. Retailers did not raise any concerns with the tariff structure for haulage services.

Our view is that the proposed tariff structure meets our regulatory obligations:

- **National gas objective (NGO):** The current tariff structure includes both a fixed charge and a usage charge component. This tariff structure design provides price signals to customers regarding their efficient usage of the network thus contributing to the achievement of the NGO.
- **Transaction costs:** NGR 94(4)(b)(i) requires transaction costs that are associated with charging parameters to be considered. Maintaining the existing tariff structure avoids potentially costly changes to systems (including retailer systems) and processes that may be required should the tariff structure change.
- **Responding to price signals:** NGR 94(b)(ii) requires that tariffs must have regard to the ability of customers to respond to price signals. Maintaining a relatively simple tariff structure of a standing charge and two usage bands makes it easier for customers to understand the effect on the distribution charge of connection or changes in consumption. Similarly continuing with a known tariff structure makes it easier for customers to understand distribution charges.

Table 19.2 shows the proposed AA5 tariff structure for each tariff class (noting that we have adopted a single tariff class for each reference service).

**Table 19.2:** Tariff structure

| REFERENCE SERVICE (TARIFF CLASS) | SERVICE ELEMENT | CHARGING PARAMETER |
|---|---|---|
| **A1** | Fixed charge for using the distribution system | Standing Charge ($/year) |
| | Fixed charge for the capacity of network utilised (reflecting maximum hourly quantity (MHQ) and pipeline length) | Demand Charge ($/MHQ GJ/km) |
| | Variable charge based on throughput and haulage distance | Usage Charge ($/GJ/km) |
| | Charge to reflect the specific costs associated with the customer for service pipe, regulators, metering, and telemetry | User specific Charge ($) |
| **A2** | Fixed charge for using the distribution system | Standing Charge ($/year) |
| | Variable charge based on throughput | Usage Charge ($/GJ) |
| | Charge to reflect the specific costs associated with the customer for service pipe, regulators, metering, and telemetry | User specific Charge ($) |
| **B1** | Fixed charge for using the distribution system | Standing Charge ($/year) |
| | Variable charge based on throughput | Usage Charge ($/GJ) with two blocks |
| | Charge to reflect the specific costs associated with the customer for service pipe, regulators, metering, and telemetry | User specific Charge ($) |
| **B2** | Fixed charge for using the distribution system | Standing Charge ($/year) |
| | Variable charge based on throughput | Usage Charge ($/GJ) with two blocks |
| **B3** | Fixed charge for using the distribution system | Standing Charge ($/year) |
| | Variable charge based on throughput | Usage Charge ($/GJ) with three blocks |

We have considered the following matters in choosing to maintain the AA4 tariff structures for AA5:

- **A1 demand charge**: The A1 tariff structure (typically industrial customers) also includes demand charges. These demand charges reflect the direct effects that these customers can have on network requirements. The A1 tariffs are based on the '*maximum usage of that customer at any point in time*', measured as gigajoules per hour (GJ/h) (referred to as capacity-based prices). Capacity, also known as demand-based prices, encourage a smoother usage profile, rather than a 'peaky' profile. Smoother usage profiles lead to lower network costs and higher network utilisation, as network capacity does not have to meet short-term volatility in usage. Increasing use of the network lowers total costs to all customers per unit of gas delivered; supporting the NGO of increasing efficient utilisation of the network.
- **A1 distance-based charges**: The A1 tariff class usage charges are a product of consumption and km of pipeline over which the gas is hauled. This form of tariff reflects the need to provide capacity to these large customers over the distance to the delivery point. Therefore, the usage charges more accurately reflect the cost of service dependent on the end-user's delivery point location which in turn provides price signals for the efficient use of, and investment in, the network as required by the NGO.

- **B3 usage charge (first 1.825 GJ):** The proposed B3 tariff structure has no charge for the first 1.825 GJ, as in AA4. The zero charge for the first 1.825 GJ has been maintained into AA5 because:
  - It provides an incentive to low-volume users to stay connected or connect to the network. This helps spread the fixed costs of the network across more customers to the benefit of all customers.
  - Maintains consistency of pricing between AA4 and AA5 to allow easier comparison of distribution charges across access arrangement periods contributing to a better understanding of price signals.
  - Annual consumption of 1.825 GJ is unlikely to contribute enough to peak load to force amendments to the network and so effectively has a cost close to nil. This is so because B3 tariff class consumption peaks are spread throughout the day. B3 consumption peaks between 5am and 9am with secondary peaks at noon and throughout the evening. Also, with an annual consumption of up to 1.825 GJ, it is unlikely the end user will have high-volume appliances such as a space heater or instantaneous water heater contributing to peak loads.

### 19.7.2 Tariff structure: *ancillary services*

Ancillary services are charged at the same rate to all customers within the relevant tariff classes, or at a rate to reflect the specific costs of the individual service provided. The rates charged reflect the cost to provide the service, and so promote efficient use of the service.

Table 19.3 shows the proposed tariff structures for ancillary services for AA5, which includes the new special meter reading service.

**Table 19.3:** Ancillary services tariffs

| ANCILLARY SERVICE | CHARGING PARAMETER |
|---|---|
| **Apply meter lock** | Published tariff per activity |
| **Remove meter lock** | Published tariff per activity |
| **Deregistering a delivery point** | Published tariff per activity plus the reasonable cost to ATCO to deregister the delivery point |
| **Disconnect service** | Published tariff per activity |
| **Reconnect service** | Published tariff per activity |
| **Special meter reading** | Published tariff per activity |

## 19.8 AA5 tariff charging parameters

This section details our process and considerations to establish the AA5 tariff charging parameters. Further details are provided in Attachment 19.1.

### 19.8.1 Background and context

AA4 commenced on 1 July 2014; however, due to the time required to complete the AA4 regulatory process, prices remained at 2013/14 levels[95] until 1 October 2015. This resulted in the current AA4 price path, where the cost of service in 2019 is below our expected tariff revenue (see Figure 19.7).

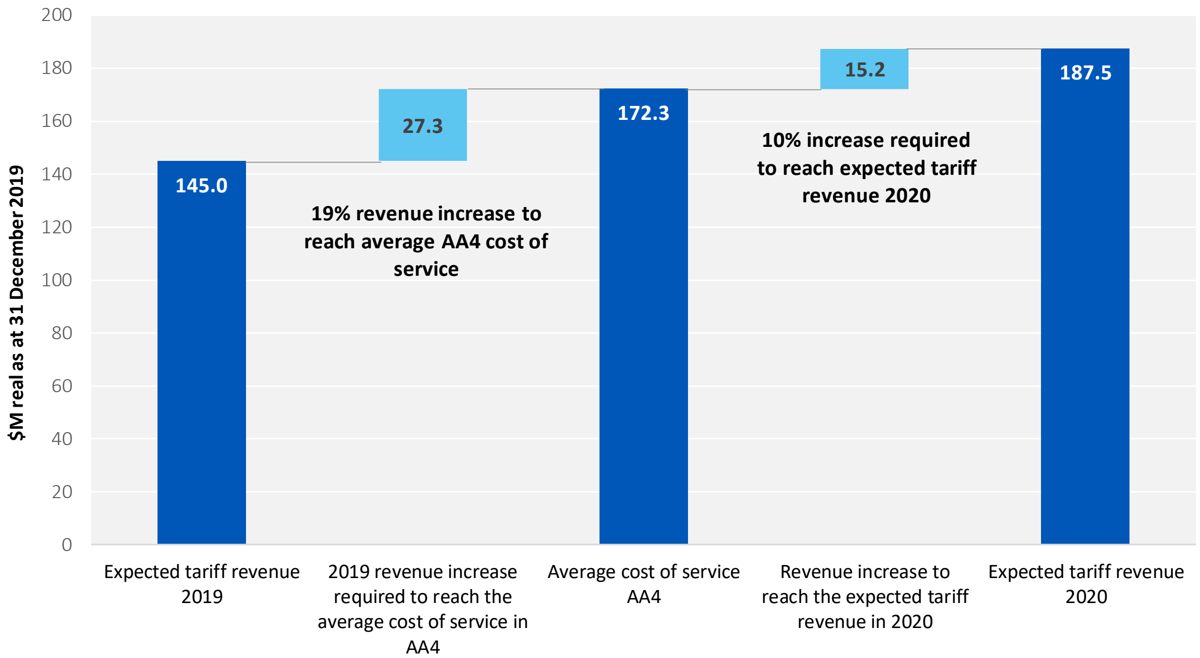
Also, over AA4 the standing charge for the B3 tariff class was increased to ensure recovery of fixed costs while B3 tariff class usage charges declined. These charges have led to a situation where, based on analysis

95 After adjustment for the removal of the carbon tax on 1 July 2014

of actual network growth projects, the marginal usage tariff in 2019 is expected to be below long run marginal cost. Together this potentially results in price signals, if maintained, that will cause inefficient network investment and inefficient network utilisation.

Figure 19.7 shows that almost two thirds (19%) of the 29% revenue increase in 2020 is necessary just to return prices back to the average AA4 cost of service. The remainder of the revenue increase (10%) is required to recover the 2020 cost of service.

**Figure 19.7:** Tariff revenue requirements to meet our cost to serve




## 19.8.2 Process to set reference tariff charging parameters

The tariff setting process adopted for AA5 can be summarised as follows:

1. Allocate costs to reference services, noting that each haulage reference service corresponds to a single tariff class, so that tariffs can be set to recover those costs.
2. Estimate the long-run *marginal cost* of providing the reference services so that tariffs can be set to promote efficient utilisation of the network.
3. Set tariff components so the usage charge accounts for the long-run marginal cost and that the costs of providing the reference service are recovered.
4. Confirm that for each tariff class, the revenue expected to be recovered by the tariff charges lies between an upper bound of the stand-alone cost of providing the reference service and a lower bound of the avoidable cost of providing the reference service.

In addition, we have considered the objectives set out in Section 19.4 as part of the process of setting the reference tariff charging parameters.

## 19.8.3 AA5 reference tariff charging parameters outcomes

The process to set the tariffs over AA5 results in a step-change in prices on 1 January 2020 followed by smaller increases during AA5. There are some differences to other tariff classes in the B3 tariff class as a result of the pricing of the B3 tariff class over AA4.

For the B3 tariff class we have:

- Retained the fixed charge at 2019 levels in real dollars throughout AA5.
- Increased the marginal usage charge in 2020 to $6.22 ($ real as at 31 December 2019) taking into consideration long run marginal cost.
- Applied an annual 2.3% real increase to the usage charges.
- Retained no charge for the first 1.825 GJ to promote utilisation of the network and stability in distribution charges.

Table 19.4 summarises the proposed price movements for each tariff class over AA5.

**Table 19.4:** Summary of pricing outcomes

| TARIFF CLASS | REAL PRICE CHANGE ON 1 JANUARY 2020 | | SUBSEQUENT ANNUAL REAL PRICE CHANGES (1 JAN 2021 – 1 JAN 2024) | |
|---|---|---|---|---|
| **A1, A2, B1, and B2** | 22.4% | | 2.3% | |
| **B3** | Fixed: 0% | Marginal usage charge increased to $6.22 | Fixed: 0% | Variable: 2.3% |

In setting the AA5 reference tariff charging parameters we have considered the following matters:

- **Usage charges:** Usage charges reflect costs placed on the network by *additional usage*. That is, the marginal usage charge has been set taking account of long run marginal cost of providing additional capacity. The first band of usage charges is set for an initial level of consumption to assist with recovery of costs not recovered by the marginal usage charge. AA5 usage charges have increased to align the cost of service and expected tariff revenue.

  Using a 2-band tariff structure helps reduce the barrier of a higher fixed charge to customers connecting and thus promotes the sharing of fixed costs across a larger number of customers to the benefit of all customers. Using a 2-band tariff structure is also generally consistent with the band structure of retailers, creating the potential for better transmission of distribution charge price signals to end users. There is regulatory precedent for multiple usage bands in gas distribution recognising the positive incentive effects on network utilisation.
- **Fixed charges:** The fixed charge is set to recover the cost of service *not recovered via the usage charges*. The use of fixed charges to recover this 'residual revenue' minimises the distortion to price signals and is supported by regulatory precedent.
- **Efficient cost recovery:** Amendments to our reference tariffs allow our expected tariff revenue by tariff class to approximate the estimated costs of service by tariff class.
- **Comparison with historical tariffs:** Comparisons were made against historical tariffs and distribution charges at average levels of consumption to ensure movements in the average distribution charge were within tolerable limits, particularly for small use customers. Distribution charges at average consumption were found to be either lower than or only slightly higher than inflation increases over AA4.
- **Customer and retailer pricing preferences:** The initial 2020 tariff increase proposed in our Draft Plan has been reduced, instead introducing a 2.3% real increase in tariffs for the years 2021 to 2024. The 2.3% annual increase was the highest annual increase possible that would keep the difference in cost of service and expected tariff revenue within 3% of the cost of service. Keeping the differential in 2024 within 3% reduces the potential for price shock in the transition from AA5 to AA6.

The following sections provide further detail on the movements in the tariffs over AA5 and outline the associated rationale.

### 19.8.4 B3 reference tariff

We propose to apply a step change on 1 January 2020 to the usage charging parameters for the B3 reference tariffs followed by annual price increases. The standing charge for the B3 reference tariff will remain at 2019 levels in real terms over AA5.

#### B3 usage charges

The B3 tariff includes three usage charges that are based on consumptions bands. The bands are defined as follows:

**Table 19.5:** B3 usage bands

| BAND | VOLUME | CHARGING BASIS |
|---|---|---|
| **1** | First 1.825 GJ | $/GJ |
| **2** | Volume >1.825 < 9.855 GJ | $/GJ |
| **3** | Volume > 9.855 GJ | $/GJ |

The first step in setting usage charges was to set the marginal usage charge at a value that considered marginal cost. Marginal cost estimation showed a wide range of values based on theoretical perturbation method calculation as well as the results from actual and forecast growth projects.

Based on that analysis[96], a value of approximately $6 is reasonable. A value of $6 is also consistent with historical levels of the marginal usage charge. Therefore, the marginal usage charge was set at $6.22 per GJ. Although this is an approximate $4 increase on the forecast value of the B3 tariff class marginal usage charge in 2019, usage charges have decreased during AA4 to below long run marginal cost, and the B3 fixed charge was increasing, leading to disproportionate decreases in the B3 usage charges.

The first 1.825 GJ of consumption has been maintained at *no charge* over AA5. No charge on the first 1.825 GJ was introduced during AA4 to offset the effect on small use customers of an increasing standing charge. Although those standing charges have now reached a stable level, it is proposed that no charge for the first 1.825 GJ be maintained for the reasons discussed in Section 19.7.1.

In summary, the B3 usage charges:

- Provide an incentive to low volume users to stay connected or connect to the network, which helps spread the fixed costs of the network across many customers to the benefit of all customers.
- Maintain consistency of pricing between AA4 and AA5 to allow easier comparison of distribution charges across access arrangement periods contributing to a better understanding of price signals.
- Maintain stability in tariff structures, as valued by retailers and customers. Stability promotes greater understanding of the distribution charges leading to better price signals, avoiding potential system changes by retailers, and minimising ATCO's transaction costs (NGR 94(4)(b) (i) and (ii)).

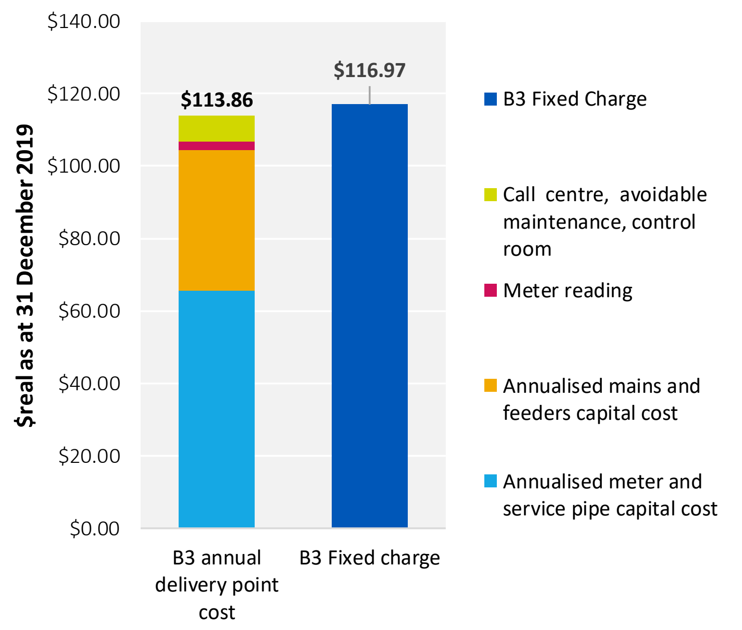
Given the other charges set, including the standing charge (see below), the charge for the usage band greater than 1.825 GJ up to 9.855GJ was set to recover the "residual" cost of service for the B3 tariff class. The value proposed for 1 January 2020 is $8.38 in real 31 December 2019 dollars.

After setting the tariffs for 1 January 2020, usage charges were increased at the rate of 2.3% (real) so that in NPV terms, the cost of service approximated expected tariff revenue.

96 Refer to attachment 19.1: '*Tariff setting method*'

### B3 tariff – Standing (fixed) charge

Figure 19.8: B3 Fixed Charges vs Cost of Delivery




The B3 fixed charge has been held constant at the forecast 31 December 2019 real dollar value of $116.97. Over AA4, the B3 tariff class standing charge increased from $77.93 to better approximate the fixed costs of a delivery point. The charge has now reached a level where fixed costs of an additional delivery point are recovered and so has been held constant over AA5 in real dollar terms (see Figure 19.8).

Holding the fixed charge constant in real dollar terms reduces the barrier to new connections relative to what it would be with an increased standing charge. Lowering the barrier promotes new connections so that fixed costs can be spread over a larger customer base, provided as shown above the marginal delivery point cost is recovered by the standing charge, to the benefit of all customers. Holding the delivery point constant in real dollar terms in concert with the proposed usage charges ensures the economically efficient recovery of all B3 tariff class costs of service over AA5.

### 19.8.5 A1, A2, B1 and B2 reference tariff

We are proposing to apply a step change on 1 January 2020 to all charging parameters for the A1, A2, B1 and B2 reference tariffs followed by annual price increases.

As noted at Section 19.8.1 tariffs have declined over AA4 to the point where tariff revenue is below the cost of service. As required by NGR 92(2) and 94(5), tariffs must be set to equalise (in NPV terms) the cost of reference services and the expected revenue from reference services. To meet this requirement, we are proposing:

- a 22.4% real increase in tariffs on 1 January 2020; plus
- a real 2.3% increase per year from 2021 to 2024.

Given 2019 expected tariff revenue is below the cost of service and the annual tariff increases of 2.3% from 2021 to 2024, an initial price increase of 22.4% is required, to equate in NPV terms over AA5 the cost of service and expected tariff revenue as required by NGR 92(2) and 94(5).

For stability, the relativities across tariff charges have been maintained with equal price increases across tariff classes A1, A2, B1 and B2 as well as the charging parameters within those tariff classes. The marginal usage charges have been confirmed to be within the ranges suggested by marginal cost analysis.[97] Checks were also made against historical tariffs to confirm that tariffs were in line with historical averages.

The proposed tariffs consider the effect on small use customers and retailers; average annual distribution charges in AA5 (for an average consumption customer) are in line with AA4 averages in real dollar terms.

[97] Refer to attachment 19.1: 'Tariff setting method'

### 19.8.6 Long run marginal cost estimates

We have estimated the long run marginal costs for each reference service to set the variable charging parameters. The estimates by tariff class are shown in Table 19.6.

**Table 19.6:** Long run marginal cost estimates ($ real as at 31 December 2019)

| | A1 | A2 | B1 | B2 | B3 |
|---|---|---|---|---|---|
| Average perturbation method | 1.40 | 0.57 | 1.12 | 1.10 | 1.44 |
| Average forecast/actual projects | 1.43 | 1.56 | 1.98 | 3.96 | 5.93 |
| Forecast 2020 marginal usage tariff | 0.21* | 1.14 | 3.63 | 4.21 | 6.22 |

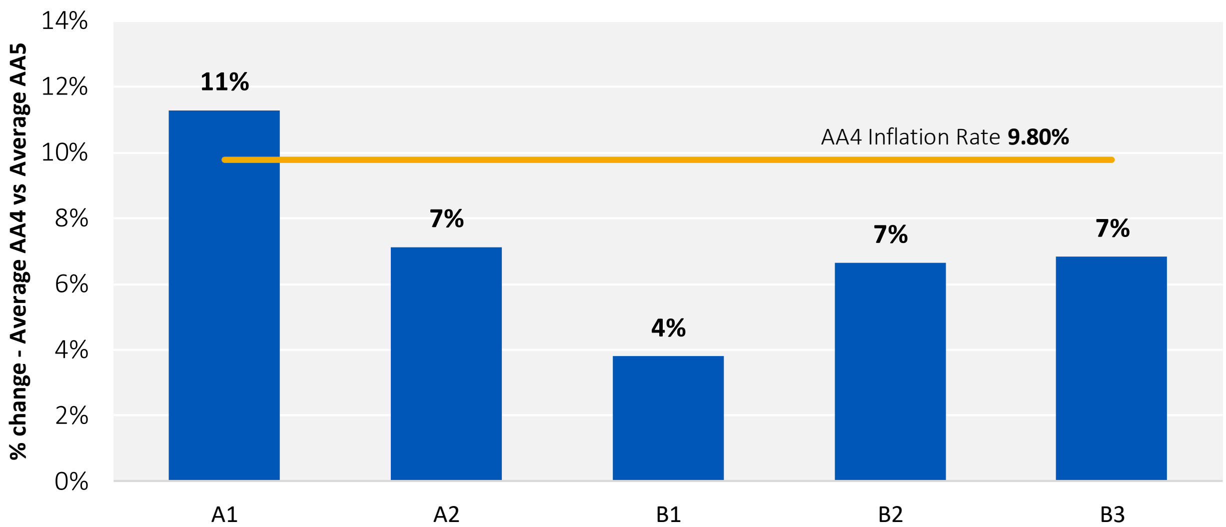
* Based on average 6 km distance from transmission pipeline

Further detail on our long run marginal costs estimates can be found in Attachment 19.1.

### 19.8.7 AA5 price path summary

Figure 19.9 shows the percentage increase in the distribution charge at average consumption over AA4 compared to the distribution charge at average consumption over AA5 by tariff class. In nominal terms, the increases range from 4% to 11%, which compares to inflation over AA4 of 10%.

**Figure 19.9:** Difference between average AA4 and AA5 distribution charges by tariff class




Although the same percentage tariff increases have been applied to all tariffs, the percentage increase in the distribution charge at average consumption will vary due to the movement in average consumption from AA4 to AA5 and the relative effects of different tariffs at average consumption for different tariff classes.

## 19.9 Indicative prices

This section details indicative prices for each tariff class over AA5. The actual prices charged in each year are likely to differ from these indicative prices due to the annual operation of the tariff variation mechanism. This mechanism allows prices to change due to inflation, the annual update for the cost of debt, and cost pass through events. The tariff variation mechanism is detailed in Chapter 20 and documented in Annexures B, C and D of the proposed access arrangement.

Customers relying on this information to make business or investment decisions should consider the potential volatility between an indicative price and a final outturn price and the risks inherent in relying on them. Table 19.7 shows the proposed tariffs in nominal dollars before any tariff variation is applied.

**Table 19.7:** Proposed haulage tariffs ($ nominal 2019)

| CHARGING PARAMETER | UNITS | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|
| **REFERENCE TARIFF A1** | | | | | | |
| **Standing charge** | $/year | 40,443.62 | 42,135.10 | 43,897.32 | 45,733.25 | 47,645.96 |
| **Demand charge** | | - | - | - | - | - |
| First 10 km | $/GJ km | 170.50 | 177.63 | 185.06 | 192.80 | 200.86 |
| Distance > 10 km | $/GJ km | 89.75 | 93.51 | 97.42 | 101.49 | 105.73 |
| **Usage charge** | | - | - | - | - | - |
| First 10 km | $/GJ km | 0.03607 | 0.03758 | 0.03914 | 0.04078 | 0.04248 |
| Distance > 10 km | $/GJ km | 0.01817 | 0.01893 | 0.01972 | 0.02055 | 0.02141 |
| **REFERENCE TARIFF A2** | | | | | | |
| **Standing charge** | $/Year | 22,382.29 | 23,318.39 | 24,293.64 | 25,309.68 | 26,368.21 |
| First 10 TJ | $/GJ | 2.17 | 2.26 | 2.36 | 2.45 | 2.55 |
| Volume > 10 TJ | $/GJ | 1.16 | 1.21 | 1.27 | 1.32 | 1.38 |
| **REFERENCE TARIFF B1** | | | | | | |
| **Standing charge** | $/Year | 1,134.62 | 1,182.07 | 1,231.50 | 1,283.01 | 1,336.67 |
| First 5 TJ | $/GJ | 4.30 | 4.48 | 4.67 | 4.86 | 5.06 |
| Volume > 5 TJ | $/GJ | 3.70 | 3.85 | 4.01 | 4.18 | 4.36 |
| **REFERENCE TARIFF B2** | | | | | | |
| **Standing charge** | $/Year | 282.81 | 294.64 | 306.96 | 319.79 | 333.17 |
| First 100 GJ | $/GJ | 7.21 | 7.51 | 7.83 | 8.15 | 8.49 |
| Volume > 100 GJ | $/GJ | 4.29 | 4.47 | 4.66 | 4.85 | 5.05 |
| **REFERENCE TARIFF B3** | | | | | | |
| **Standing charge** | $/Year | 119.12 | 121.31 | 123.55 | 125.82 | 128.13 |
| First 1.825 GJ | $/GJ | - | - | - | - | - |
| Volume > 1.825, < 9.855 GJ | $/GJ | 8.53 | 8.89 | 9.26 | 9.65 | 10.06 |
| Volume > 9.855 GJ | $/GJ | 6.33 | 6.60 | 6.88 | 7.16 | 7.46 |

## 19.10 Tariff revenue

Given the above indicative tariffs, we have confirmed that the expected tariff revenue:

- in net present value terms equates to total revenue;
- for each tariff class, approximates the forecast total revenue for the tariff class; and
- for each tariff class, lies between the lower bound of avoidable cost and the upper bound of stand-alone cost over AA5.

The results of these tests showing compliance are shown in Table 19.8

**Table 19.8:** Rule 94 test ($M real as at 31 December 2019)

| TARIFF CLASS | TOTAL COSTS ALLOCATED | STAND ALONE COSTS | EXPECTED REVENUE | AVOIDABLE COSTS |
|---|---|---|---|---|
| A1 | 32.4 | 183.5 | 35.3 | 7.1 |
| A2 | 22.1 | 277.3 | 21.4 | 2.8 |
| B1 | 54.9 | 433.9 | 51.7 | 9.5 |
| B2 | 48.7 | 442.0 | 52.7 | 8.1 |
| B3 | 686.3 | 781.9 | 683.6 | 120.8 |
| Ancillary services | 13.3 | 13.3 | 13.0 | 11.7 |
| **TOTAL** | **857.7** | | **857.7** | |

## 19.11 Setting tariffs: Reference ancillary services

The five reference ancillary services provided in AA4 have been retained in AA5. An additional reference service, special meter reading, has been added for AA5. The service has been added due to the increasing demand related to the entry of new retailers to the Western Australian market and the consequent requirement for meter reads when customers change retailers.

Tariffs for ancillary services are based on the cost to provide those services and to promote efficient use of the services. Tariffs for ancillary services include:

- The direct cost of operations staff and contractors providing the service.
- The direct administration cost of providing the service.
- An allocation of corporate costs such as accounting services and IT services.

Table 19.9 shows the ancillary services tariffs.

**Table 19.9:** Ancillary reference services tariffs ($ real as at 31 December 2019)

| TARIFF CLASS | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|
| Apply Meter Lock | 49.14 | 49.14 | 49.14 | 49.14 | 49.14 |
| Remove Meter Lock | 26.73 | 26.73 | 26.73 | 26.73 | 26.73 |
| Deregistration Request | 122.54 | 122.54 | 122.54 | 122.54 | 122.54 |
| Disconnect Service | 97.92 | 97.92 | 97.92 | 97.92 | 97.92 |
| Reconnect Service | 138.62 | 138.62 | 138.62 | 138.62 | 138.62 |
| Special meter reading | 12.82 | 12.82 | 12.82 | 12.82 | 12.82 |

### 19.11.1 Charges for cancelled ancillary services

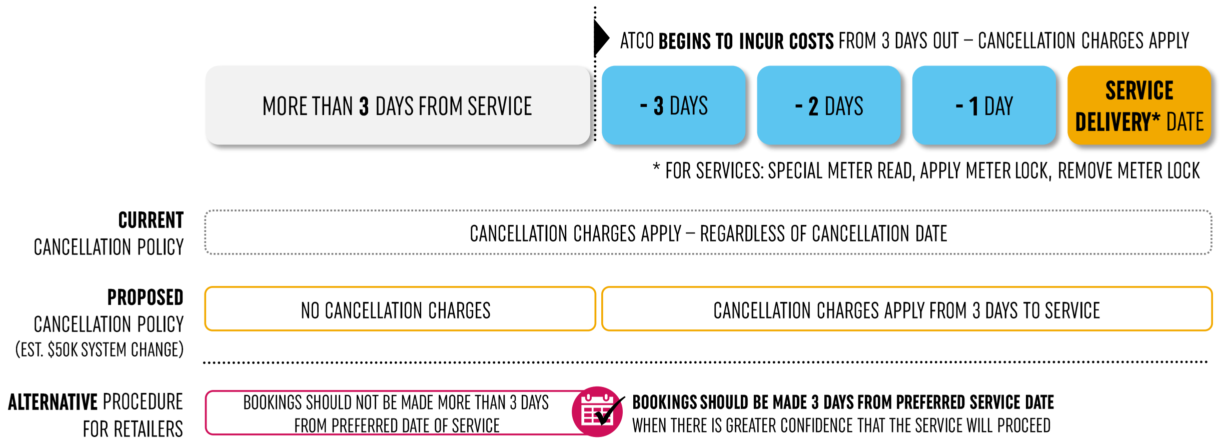
Retailers have raised the matter of *charges for cancelled ancillary services* (see Section 19.3). During AA4, we charged for *cancelled services* at the same rate as *completed services* for simplicity; given the number of cancelled services at the time of the AA4 review were not significant. Increased competition in the retail market for gas has led to more completed and cancelled ancillary services. Retailers in response to our Draft Plan suggested that services cancelled *more than two days* before the scheduled service date should have no charge or a reduced charge.

Approximately 75% of revenue from cancelled services related to cancelled special meter readings in 2017. Approximately 50% of cancelled special meter readings were cancelled more than two days before the scheduled read date.

### Apply meter lock, remove meter lock and special meter reading

We are currently investigating the effectiveness of implementing changes to our billing system to allow us to monitor the timing of cancelled service orders. This billing system change will allow service orders that incur no cost, to not incur a charge. Subject to the cost and practicality of billing system changes, charges for 'apply meter lock', 'remove meter lock' and 'special meter reading' may be reduced or have no charge if cancelled three days or more before the scheduled date of service. Services cancelled after that time will already have been sent to the contractor for action. Figure 19.10 illustrates this.

**Figure 19.10:** Cancellation charges overview




The estimated cost of system changes is $50,000. This additional IT capital cost to implement the charging of a reduced fee for cancelled ancillary services is not currently in the IT capex forecast and would have to be included in the forecast capex program for AA5 if this functionality is required.

### Deregistration, disconnect service, and reconnect service

Other ancillary services, deregistration, disconnect service and reconnect service have scheduling procedures that make it difficult to set a single cut-off date for reduced charges. These services also incur cost from the time the request is received as the service order is passed to operations departments for scheduling and action. The preferred course of action is to work with retailers to reduce the number of cancelled service orders.

Regarding all ancillary services, we welcome the opportunity to work with retailers to understand the cause of cancelled ancillary services and reduce them to the benefit of all market participants including customers. For example, retailers may want to consider changes to their booking process, so that services are booked no longer than three days out for greater confidence and less chances of cancellation (shown at the bottom of Figure 19.10).

# 20. Tariff variation mechanism

**CHAPTER HIGHLIGHTS**

1. We propose a weighted average price cap tariff variation mechanism. The mechanism allows for:
    a) an annual adjustment for CPI (weighted average across eight capital cities); and
    b) an X-factor based on the approved price path and amendments to the ERA's AA4 Final Decision tariff model. This will incorporate cost pass through items and annual updates to the DRP.
2. The method of updating the DRP is unchanged from AA4.

## 20.1 Introduction

The purpose of the tariff variation mechanism is to set out the detailed mechanism that causes our prices to be changed each year over AA5. Our annual price changes are subject to the approval of the ERA.

This chapter sets out:

- The regulatory framework regarding the tariff variation mechanism.
- The rationale for the selected tariff variation mechanism.

An important consideration in selecting a tariff variation mechanism was the desire of our stakeholders and customers for stability, as evidenced by our VoC program. It was also important to keep the tariff variation process as simple and transparent as possible, to ensure market participants can understand and forecast future tariff changes.

## 20.2 Regulatory framework

The regulatory framework for constructing a tariff variation mechanism is not prescriptive but provides guidance on what a tariff variation mechanism may contain and what form a tariff variation by formula '*may*' take. For example:

- Tariffs may be varied in accordance with a formula set out in the access arrangement and to take account of defined cost pass through events (generally cost changes that cannot be reasonably forecast as they are beyond the service provider's control).
- A tariff variation by formula may vary tariffs to set a revenue cap or a price cap on tariffs.

The NGR provides some guidance on matters to be considered when selecting a suitable tariff variation mechanism. Factors to be considered include:

- the need for efficient tariff structures;
- administrative cost; and
- the desirability of consistent tariff variation mechanisms for reference services within and across jurisdictions.

## 20.3 Stakeholder engagement

We received one item of feedback in response to our Draft Plan relating to the tariff variation mechanism, which is outlined in Table 20.1.

**Table 20.1:** Stakeholder feedback: Tariff variation mechanism

| DRAFT PLAN STAKEHOLDER QUESTION | STAKEHOLDER FEEDBACK | OUR RESPONSE TO FEEDBACK ON OUR DRAFT PLAN |
|---|---|---|
| Do you support the weighted average price cap applying over AA5?<br>Do you agree with the cost pass through events? | Retailer B supported the form of the tariff variation mechanism being a weighted average price cap and the proposed cost pass through events. | **No change** to our Draft Plan. |

## 20.4 Rationale for proposed reference tariff variation mechanism

### 20.4.1 Tariff variation by formula

We propose to implement a tariff variation mechanism that places a constraint on the overall average movement in haulage reference service prices from one year to the next (referred to as a *weighted average price cap*, or *tariff basket*).

This form of tariff variation was used during AA4 for the A1, A2 and B1 tariff classes, and for all tariff classes in previous access arrangement periods. Therefore, it is a familiar method of tariff variation for our customers and the ERA. The 'tariff basket' is a common mechanism known for its administrative simplicity and positive incentive effects and is supported by regulators in Australian jurisdictions.

The tariff variation allows average prices to increase by the annual change in CPI, plus or minus the X-factor varied for DRP updates and cost pass through items. The X-factor will be updated annually as part of the tariff variation process, by amending the approved AA5 tariff model for the DRP for the tariff variation year, as well as any cost pass through items (described in Section 20.4.2). The approved tariff model is then re-run to calculate the updated X-factor for the tariff variation year.

Using a price cap provides an incentive for the business to increase customer connections and usage, as this generates additional revenue. In future access arrangement periods, customers benefit from costs being spread over a larger number of customers and volume.

In comparison, a revenue cap does not provide any incentive to grow the network for the benefit of customers; revenue remains constant regardless of the growth of the network. Therefore, a price cap form of control is preferable to provide the incentive to grow the network in the long-term interests of consumers.

Ancillary reference services described at Table 8.3 will be varied annually by the movement in CPI in the same manner as during AA4.

### 20.4.2 Cost pass through

The tariff variation mechanism allows the cost of 'cost pass through' events to be recovered. Cost pass through events are defined events that:

- incur costs that cannot be, and have not been, reasonably forecast;
- are beyond the control of ATCO; and
- relate to the provision of reference services.

The recovery of costs related to cost pass through events is made by varying the X-factor as described in the previous section. It is proposed that the cost pass through items defined in AA4 are maintained for AA5, except for capex related to 'Intermediate' security of supply, which was a specific item related to AA4.

In summary, the cost pass through events retained into AA5 are:

- HHV and gate point costs related to new gas inflows to the network.
- Any costs relating to a change in law or tax change.
- Any costs associated with a tax, fee, law, or emissions trading scheme related to greenhouse gas emissions.

We have retained these cost pass through events as they all relate to costs that are outside of our control, and we are unable to reasonably forecast them. In addition, in AA4 we sought the recovery of costs under most of these through the annual tariff variation. It is necessary to retain the mechanism related to greenhouse gas emissions due to the ongoing energy policy uncertainty.

We have introduced a new cost pass through item to recover any costs that are recoverable under the Network Innovation Scheme.

# PART D:

## Other

# 21. Fixed principles

**CHAPTER HIGHLIGHTS**

1. We are proposing to extend two of our fixed principles that are due to expire during AA5.
2. We are introducing a new fixed principle to support the operation of the development rebate scheme.

## 21.1 Introduction

The purpose of fixed principles is to provide certainty that specific principles will not be subject to review for a stated period. This gives certainty, and reassures both customers and ATCO, that a particular principle will go unchanged for a pre-determined period.

We are proposing to extend the existing fixed principles that support the operation of the cost pass through mechanism into AA5, and have introduced a new fixed principle to support the operation of the development rebate scheme.

## 21.2 Stakeholder engagement

We sought feedback on our 2020-24 Draft Plan regarding our fixed principles. Feedback indicated that stakeholders support our extension of the fixed principles. Table 21.1 summarises the feedback received and our respective response.

**Table 21.1:** Stakeholder feedback: Fixed Principles

| DRAFT PLAN STAKEHOLDER QUESTION | STAKEHOLDER FEEDBACK | OUR RESPONSE TO FEEDBACK ON OUR DRAFT PLAN |
|---|---|---|
| Do you support ATCO extending the fixed principles that support the operation of the cost pass through mechanism to beyond 31 December 2024? | Retailer B indicated that they would support extending the current fixed principles | **Change –** ATCO has extended the existing fixed principles to beyond 31 December 2024. |
| Are there any fixed principles in ATCO's access arrangement that should be removed? | No responses received | **N/A** |
| What other new fixed principles or changes should be made to the existing fixed principles to support AA5? | No responses received | **N/A** |

## 21.3 Regulatory framework

Rule 99 of the NGR provides that an access arrangement may include principles that are fixed for a declared period. Fixed principles may be agreed on for two or more access arrangement periods.

## 21.4 Existing fixed principles

The following are the existing fixed principles in the current access arrangement. Where relevant, the expiry dates of these existing fixed principles are proposed to be extended to beyond 31 December 2024.

- **Due to expire 1 January 2021:** Extended to apply for the next Access Arrangement Period (Section 11.2 in the current Access Arrangement)

  a) the inclusion of:

    i) Physical Gate Point Costs that constitute Conforming Capital Expenditure in the Opening Capital Base for the ATCO GDS for the Next Access Arrangement Period; and

    ii) Physical Gate Point Costs that constitute Conforming Operating Expenditure in Total Revenue for the Next Access Arrangement Period in respect of the ATCO GDS.

  in respect of which Reference Tariffs have been varied as a Cost Pass Through Event.

- **Due to expire 31 December 2024:** Extended to apply for the next Access Arrangement Period (Section 11.3 in the current Access Arrangement)

  a) the inclusion of

    i) additional conforming expenditure associated with a Cost Pass-Through Event for the period 1 September 2023 to 31 December 2024. The expenditure must meet the requirements of clause 2 of Annexure B of this current access arrangement.

- **Due to expire 25 August 2025:** (Section 11.1 in the current Access Arrangement)

  a) the straight-line method of depreciation for each group of assets referred to in part 9 of the current Access Arrangement

  b) the inclusion of:

    i) HHV Costs that are Conforming Capital Expenditure in the Opening Capital Base for the ATCO GDS at the Revision Commencement Date; and

    ii) in Total Revenue HHV Costs that are Operating Expenditure for the Next Access Arrangement Period in respect of the ATCO GDS.

  in respect of which Reference Tariffs have been varied as a Cost Pass Through Event.

## 21.5 New fixed principles

We are seeking to introduce a new fixed principle to support the development rebate scheme (see Section 23.6.1). The purpose of the new fixed principle is to provide us with the ability to recover the rebate amounts and associated costs through reference tariffs in future access arrangement periods. The fixed principle will apply over the economic life of the asset as this is the period over which the rebate will be recovered through tariffs. The basis of the development rebate scheme is explained in Section 23.6.1.

# 22. Template service agreement

**CHAPTER HIGHLIGHTS**

1. We are proposing some limited changes to the template service agreement for AA5.

## 22.1 Introduction

The purpose of the template service agreement is to specify the terms and conditions for providing reference services (other than the reference tariffs, which are detailed in a schedule to the access arrangement). The template service agreement is typically adopted by retailers seeking access to the ATCO GDS and is an important part of our relationship as it governs the conditions (or terms) of access to our networks.

Based on interactions with existing and new users (retailers) and legal and regulatory developments during AA4, some limited changes are proposed to the template service agreement.

## 22.2 Stakeholder engagement

We sought feedback on our Draft Plan regarding the template service agreement. We did not receive any feedback.

## 22.3 Regulatory framework

Rule 48(1)(d)(ii) of the NGR provides that a full access arrangement must specify for each reference service, the other terms and conditions on which the reference service will be provided. Consistent with this rule, the other terms and conditions for providing reference services are specified in the template service agreement.

## 22.4 Changes to the template service agreement

The changes proposed to the template service agreement fall into the following categories:

- **Minor formatting and structural amendments:** To correct and update the document published for AA4.
- **New and modified legislation:** For example, changes to relevant applicable laws.
- **Institutional changes:** The new role of AEMO in the Western Australian retail gas market.
- **New entrants to the market:** Our practical experience of engagement on the negotiation of terms of the template service agreement with retail market participants and stakeholders.
- **New reference service:** The introduction of 'special meter reading' as a reference service.

The proposed revised template service agreement is attached at Annexure F of the Access Arrangement.

We have reviewed the template service agreement against the relevant National Gas Access (Western Australia) Legislation and Regulatory Instruments and have amended or updated the document as required.

In summary, the changes proposed to the template service agreement are as follows:

1. **Minor formatting and typographical corrections:** These are shown as tracked changes in Annexure F of the proposed access arrangement.
2. **Footnotes:** All footnotes from the existing version published on the ERA website have been removed.
3. **Substantive drafting changes:** These are shown as tracked changes in in Annexure F of the proposed access arrangement and explained in Table 22.1.
4. **Defined terms:** These are also shown as tracked changes in in Annexure F of the proposed access arrangement and identified in Table 22.1.

**Table 22.1:** Template Service Agreement amendments and updates summary

| CLAUSE REFERENCE | PAGE NUMBER | DESCRIPTION | COMMENT |
|---|---|---|---|
| **TERMS AND CONDITIONS** | | | |
| 10.1 | 29 | Minor amendment of the clause to reflect actual retail market practice | 10.1(b) and (c) have been amended to reflect the actual arrangements with retailers in the WA retail market and content of Payment Claims |
| 10.2(a) | 30 | Consequential minor amendment as per amendment to clause 10.1 | |
| 10.3(a) | 30 | Amendment to replace “10” Business days with “3” Business Days | Amended to reflect the actual arrangements with retailers in the WA retail market |
| 15.1(c) | 43 | Amendment to reflect the mutual obligations and rights of both parties | |
| 15.2(a) | 43 | Amendment to reflect changes to termination rights in cases of insolvency following the amendments introduced from 1 July 2018 pursuant to the *Treasury Laws Amendment (2017 Enterprise Incentives No. 2) Act 2017 (Cth)* | Clause amended to ensure “ipso facto” clause remains enforceable |
| 16.2 (a) | 47 | Amendment to clarify types and amounts of security for performance – use of terms “Approved Security” and “required Security Amount” in place of guarantee or bank guarantee. | Prospective users have requested various forms of security to meet the requirements of this clause. The amendments provide clarity on the types of security for performance that are acceptable, rather than providing a reference to a bank guarantee only. |
| 16.2(a)(vi); 16.2(b) to (j) | 48 - 50 | Consequential amendments to delete references to “bank guarantee” and “guarantee” to “Approved Security” | See comments above re: 16.2(a) |
| 16.3(c) | 51 | Amending “14” to “15” Business Days | Consistency of the time periods used throughout the document |

| CLAUSE REFERENCE | PAGE NUMBER | DESCRIPTION | COMMENT |
|---|---|---|---|
| 16.3(d) | 51 | Amending "14" to "15" Business Days | Consistency of the time periods used throughout the document |
| 17.1(b) | 53 | Adding a clause to clarify the enforcement of indemnification provisions amongst the parties and their indemnified persons | |
| 20(c) | 63 | Amendment to reflect the mutual obligations and rights of both parties | |
| 23.1 | 70, 71, 75, 76, 78, 79, 82, 86 | Defined Terms added or updated: Approved Security; Charge; Indemnified Person; Insolvency Event; Payment Method; Reference Service Terms and Conditions; Special Meter Reading; Variation Period | Terms added as a consequence of amendments to clauses on the basis explained above |
| **SCHEDULES** | | | |
| Schedule 1 1(b)(i)(A) | 1 | Addition of "and" | To correct a typo to ensure consistency with the published reference tariff information in Annexures A and C of the Revised Access Arrangement |
| Schedule 2 1(b)(ii)(A)(ii) | 6 | Correction of erroneous wording | To correct a typo to ensure consistency with the published reference tariff information in Annexures A and C of the Revised Access Arrangement |
| Schedule 3 9 | 13 | Addition of Special Meter Reading reference service | To incorporate the new Special Meter Reading reference service referred to in paragraph 4.12 and clause 1.6 of Annexure C of the Access Arrangement. For a discussion of the Special Meter Reading reference service please see Section 8.4. |
| Schedule 4 12 | 19 | As above | As above |
| Schedule 5 12 | 24 | As above | As above |

# 23. Policies and non-tariff components

**CHAPTER HIGHLIGHTS**

1. We are proposing to amend the application procedure to standardise the processes for both access to the regulated (covered) ATCO GDS and the Albany and Kalgoorlie non-scheme pipelines.
2. We are proposing to introduce a development rebate scheme to facilitate gas reticulation in new commercial subdivisions.
3. We are proposing a five-year period for AA5, with the AA6 period commencing on 1 January 2025.

## 23.1 Introduction

The purpose of this chapter is to detail matters that are not directly related to the reference tariffs but must form part of our access arrangement submission to the ERA. These include:

- The application procedure.
- Capacity trading requirements.
- Extension and expansion requirements.
- Changing receipt and delivery points.
- Review Submission and Revision Commencement Dates.

## 23.2 Stakeholder engagement

We sought feedback on our Draft Plan regarding the non-tariff components. We did not receive any feedback.

Separately, we received feedback from land developers that the costs to reticulate and connect commercial subdivisions to our network prevent them from including our gas network in the subdivision. We have sought to address this feedback through the introduction of the development rebate scheme.

## 23.3 Regulatory framework

Rule 48 of the NGR provides that a full access arrangement must specify certain matters, including those matters identified in Rule 48(1)(f), (1)(g), (1)(h) and (1)(i).

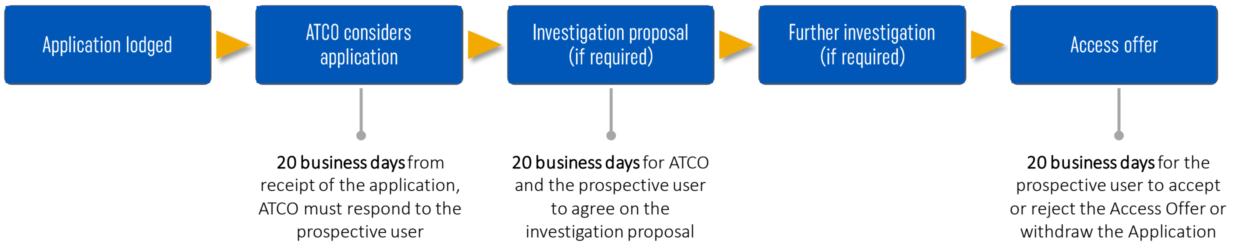
Rule 112 of the NGR specifies the requirements of, and the framework for, our access application procedure.

## 23.4 Application procedure

The application procedure set out in the access arrangement details the process that will be followed when a prospective user, wishing to obtain access to a pipeline service, submits an application to ATCO. The application procedure is specified in our access arrangement and incorporates the requirements of NGR 112.

Our application procedure and associated response times for submitting an application are summarised in Figure 23.1.

**Figure 23.1:** Application procedure stages and response times




Our application procedure remains largely unchanged from AA4. We have taken the opportunity to standardise the processes for both access to the regulated (covered) ATCO GDS and the Albany and Kalgoorlie non-scheme pipeline, including:

- Providing prospective users with links to ATCO's contact details.
- Replicating the confidentiality provisions within the AA5 application procedure.
- Specifying an Application Form for ease of use of prospective users, which is set out in Appendix G of the Access Arrangement. The application form has the same 'look and feel' as the non-scheme pipeline form but has some modifications to meet the requirements of NGR 112 and the Access Arrangement.
- Information on where the non-scheme pipeline user guide can be found. While not strictly required, this information may be useful to prospective users that are not familiar with the Western Australian gas market.

We have also amended the drafting of one of the *pre-conditions to*, and *restrictions on*, the provision of pipeline services to clarify our intent by adopting the phrase 'in accordance with accepted good industry practice' in place of the existing drafting. This phrase is also adopted in the NGR.

## 23.5 Capacity trading requirements

The capacity trading requirements provide for the transfer of capacity to a third-party. The capacity trading requirements are specified in our access arrangement and the template service agreement and are required by NGR 48(1)(f).

We have not identified any changes required to the capacity trading requirements for AA5.

## 23.6 Extension and expansion requirements

The purpose of the extension and expansion requirements is to specify whether the access arrangement will apply to incremental services to be provided as a result of a particular extension to, or expansion of the capacity of, the pipeline and deal with the effect of the extension or expansion on tariffs. These requirements are specified in the access arrangement and are required by NGR 48(1)(g).

Our extension and expansion requirements provide for:

- ATCO to apply to the ERA for the following types of extensions to be covered by the access arrangement:
  - a high-pressure pipeline extension.
  - a new direct connection to a transmission pipeline that provides reticulated gas to a new development or an existing development not serviced with reticulated gas.
- All other pipeline extensions designed to operate at 1,900kPa or less to be covered by the access arrangement.

- All expansions to the GDS to be covered by the access arrangement.
- ATCO to report to the ERA annually details of the extensions and expansions in progress or completed.

Since publishing the Draft Plan, we have made changes to the extension and expansion requirements to incorporate a development rebate scheme and some other minor amendments.

### 23.6.1 Development rebate scheme

We have received feedback from land developers that the costs to reticulate and connect commercial subdivisions to our network prevent them from including extensions or expansions of our gas network in the subdivision. This means that future commercial tenants in the subdivision will not have access to gas as an energy option. Typically, a large portion of the costs to reticulate a commercial subdivision is borne by developers upfront because of the difficulties in forecasting gas consumption and incremental revenue for the future commercial tenants.

Based on this feedback, we have investigated and proposed to introduce a development rebate scheme as part of meeting our extension and expansion requirements. This scheme will overcome the barriers that developers have informed us they face when considering connecting commercial sub-divisions to our network. A fixed principle has been added that supports the recovery of any rebates in future access arrangement periods. The rebate scheme is part of the extension and expansions requirements as it addresses the effect of the extension or expansion on reference tariffs. There are no other relevant provisions that relate to the establishment or operation of a rebate scheme under the National Gas Rules or the NGL.

Under the proposed scheme, a developer will receive a rebate following the connection of customers to the extension of our network for some or all the funding it originally provided ATCO to reticulate gas in the subdivision, provided the Extension meets the criteria in clause 7.5 of the access arrangement.

The amount of the rebate will reflect the amount that we determine meets the conforming capex test set out in NGR 79. The effect of the scheme is that the developer will receive a rebate for the connection, which will then be treated as capital costs and form part of our RAB. The effect of the scheme is to allow us to earn a return on and return of the rebate amount in future access arrangement period over the life of the asset. We will then recover these costs through reference tariffs in future access arrangements.

The scheme provides for an agreement to be put in place between ATCO and the developer that sets out relevant operational rights and obligations.

We have sought to minimise the administration costs of the scheme by limiting it to subdivisions where the capital funding provided by the developer is in excess of $50,000.

The benefits of the development rebate scheme are that commercial tenants of the sub-division will have access to a choice of energy to run their business. This choice would not otherwise be available in the absence of the rebate scheme. Other customers will also benefit from the scheme because:

- they will not have to underwrite the upfront investment in connecting the commercial sub-divisions to the gas distribution network; and
- if commercial customers in the sub-division connect then the additional connections and demand will reduce the prices payable by all customers achieving outcomes that are consistent with the NGO.

### 23.6.2 Other amendments

- **Reporting timeframes for extensions and expansions:** We report annually to the ERA with the details of GDS extensions and expansions that are in-progress or completed. We have found the timeframes to prepare the reports to be administratively challenging to prepare in the 20 business days allowed for each January due to the normal summer holiday and closedown period. We have proposed for AA5 to extend the timeframe for reporting extensions and expansions to *40 business days* following the expiration of the calendar year and submit that this would not have any adverse effect on relevant parties.
- **Definition of the pressure threshold for HP pipelines:** We have also made a minor amendment to the definition of the pressure threshold for high pressure pipelines from 1,920kPa to 1,900kPa to be consistent with definition of "distribution network" set out in S.3 of the *Energy Coordination Act (1994)* definition.

## 23.7 Changing receipt and delivery points

The changing receipt and delivery point provisions provide for a user to change a receipt or delivery point subject to certain conditions. These provisions are specified in our access arrangement and the template service agreement and are mandated by NGR 48(1)(h).

We have not identified any requirement for any changes to the changing receipt and delivery points provisions for AA5.

## 23.8 Review Submission and Revision Commencement Dates

As mandated under NGR 48(1)(i), we are proposing that the duration of AA5 will be five years. This compares to a five-and-a-half-year period for AA4 that was adopted to align regulatory years with calendar years.

The review submission date for AA6 will be 1 September 2023. This is consistent with the timing of revisions provided for under our current access arrangement and as mandated by NGR 49 and 50. Our experience is that this review submission date allows sufficient time for the consideration of the proposed revisions.

The revision commencement date for AA6 will be 1 January 2025.