AusNet

ACCESS ARRANGEMENT INFORMATION

Gas access arrangement review 2024–28

CEO foreword

AusNet delivers safe and reliable gas and electricity to more than 6 million Victorian customers. Our aim is to maintain affordable, safe and reliable energy network services for our customers, and ensure they are well placed to benefit from the energy system transformation that is underway.

I am, therefore, pleased to share our Proposed Access Arrangement for our gas network for the 5-year period commencing 1 July 2023. This Proposal will now be considered by the Australian Energy Regulator (AER), who will seek further feedback through their own review process.

This Proposal has been prepared in a period of great uncertainty, with the Australian energy market facing several geopolitical and domestic challenges affecting both the cost and speed of the transition to a decarbonised energy sector. Nonetheless, the requirement to decarbonise is certain as the Victorian Government has legislated a long-term target for Victoria of net-zero greenhouse gas emissions by 2050 with interim targets for 28–33% cuts by 2025 and 45–50% cuts by 2030. While it is unclear what part the gas sector will play in a decarbonised Australian economy, the need to prepare our network for major change is certain.

In the near term, we expect issues such as appliance switching, building design and choices and pricing will continue to moderate per customer gas consumption. In the longer term, we could see either significant transition to a renewable gas network, or customers leaving the gas network as they electrify their energy usage. However, it is important to recognise that, under either pathway, customers will need reliable and safe gas distribution services for decades to come.

To help us determine how the future of gas may unfold, and therefore the shape of our Proposal, we drew heavily on the advice of an independent Expert Panel. While this Expert Panel identified four possible future gas scenarios, we have not looked to 'pick a winner'. Rather, we have taken a pragmatic approach that allows us to provide safe and affordable services while also positioning ourselves to be able to take advantage of any new information that clarifies the future pathway for decarbonisation.

We have also engaged in a robust and transparent conversation with our customers on these difficult issues and, in an Australian first, we have done this jointly with the other two Victorian gas networks – Australian Gas Networks and Multinet Gas Networks. While this engagement has been undertaken largely online (due to the COVID-19 pandemic, Government health advice and customer preferences), it has proven to be a very effective approach that has helped us improve our Proposal. I would like to thank all who have given their valuable time and insights into this process.

A key message we have taken from this engagement is that affordable energy remains our customers' primary concern and I am proud our Proposal delivers immediate price relief while also facing head-on the longer-term challenges to price stability and investment certainty. This has been possible through us looking to recover our investment in the network at a slightly faster rate than usual (through an approach known as accelerated depreciation). Given the level of uncertainty we are facing, and our obligations to keep investing in the gas network, accelerated depreciation is the best way for us to maintain stable long-term prices. Lower future prices are also key to assisting the gas network to remain competitive if we transition to a lower emissions gas (i.e., hydrogen) network or, where the gas network needs to be wound down.

Given the speed and evolving nature of the energy system transformation that is currently underway, we anticipate that there may be some changes to our operating environment prior to the AER's final decision in early 2023. We are, therefore planning to undertake further consultation with our customers and stakeholders prior to lodging our Revised Proposal in January 2023.

Despite this uncertainty, we will continue to provide Victorian gas customers with safe and reliable gas services at affordable price now and in the longer term. I hope the information we have provided allows you to engage with it.

The AER will now review our Proposal and will seek further feedback from all customers and their representative bodies. You can engage with this process through the AER website.

Tony Narvaez

Chief Executive Officer

AusNet

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1. Introduction

This submission, including all supporting documents, collectively the 'Access Arrangement Information', sets out our regulatory proposal for the 2024-2028 access arrangement period.[1] That is the regulatory period commencing 1 July 2023 and ending 30 June 2028.

Our proposal looks to help customers and other key stakeholders to understand:

- The background to our access arrangement proposal for the access arrangement period commencing on 1 July 2023.
- The basis and derivation of the various elements of our access arrangement proposal.[2]

All information provided in this submission is in real 2023 prices unless stated otherwise.

1.1. Chapter structure

The remainder of this chapter is structured:

- Section 1.2 sets out the context of this review.
- Section 1.3 provides information on the regulatory background on which we have built our access arrangement proposal.
- Section 1.4 outlines the composition of our proposed access arrangement.
- Section 1.5 provides an overview of regulatory framework.
- Section 1.6 provides a brief overview of our gas distribution business.
- Section 1.7 sets out the structure of the remaining aspects on this document.

1.2. Context of this review

The transformational changes across the energy sector is continuing and gas is no exception. While there is significant uncertainty, there are two likely paths. Down one, lies electrification—where homes and businesses throughout Australia will be powered by a single fuel; down the other lies hydrogen—a zero-emissions fuel that will give customers a real choice in how they power their homes and businesses.

We believe that a decarbonised gas network can play a vital role in Victoria's future energy mix and that keeping this possibility open is in the best interests of our customers and Victoria as a whole.

In developing our proposal we have, therefore, left the door open to different possibilities and have engaged with our customers extensively. This is the only way we can prepare for a zero-emissions network while retaining a focus on the need for safety, reliability, affordability, customer service, innovation and education that our customers have told us they need. This is an issue we explore in more detail later in this document (Chapter 3).

However, in February 2022, in the final months prior to submitting this proposal to the Australian Energy Regulator (AER), the Victorian Government held a Gas Substitution Roadmap Forum. In that Forum, the Victorian Government outlined the results of some modelling that suggested a significantly more aggressive transition to electrification than we (and therefore our stakeholders) had considered in developing our forecasts.

However, at both the Forum and in subsequent meetings, the Victorian Government has been clear that:

- The outcomes of the Gas Substitution Roadmap modelling that was shared with stakeholders was preliminary modelling.
- The outcomes from its Gas Substitution Roadmap modelling is one of many factors that will be considered by the Victorian Government when and if it develops new policies on gas.

[1] This document is by AusNet Gas Services Pty Ltd ABN 43 086 015 036 (AusNet) to the Australian Energy Regulator.
[2] This is done in accordance with rule 42(1) of the National Gas Rules (NGR).

- There are no new gas policies that it could share with us (and other stakeholders) at the time of preparing this submission that supported the outcomes outlined under the Gas Substitution Roadmap modelling.

Given these circumstances, we have prepared our forecasts based on the evidence that is reasonable (see section 1.3). Should, following the submission of our proposal, the Victorian Government announce new policies on gas and/or emissions, we will need to carefully consider the implications of those announcements to our proposal. These implications could necessitate revisiting several issues explored in this document, including our capital expenditure, operating expenditure and depreciation proposals.

Given the timeframes we must operate within, where there is a significant change in a policy after the submission of this proposal, the scope for significant stakeholder engagement on the necessary changes may be less than would otherwise be the case. Constraints notwithstanding, we will nonetheless look to engage with our customers should we find ourselves in this situation.

Our proposal has, therefore, been prepared in uncertain times so we welcome further feedback from our customers and stakeholders on our plans as further information becomes available. We also look forward to discussing our proposal, in detail, with the AER.

1.3. Regulatory background

The National Gas Law (NGL) and the National Gas Rules (NGR) set out the regulatory framework for gas pipelines. Under the NGL, the AER is responsible for the economic regulation of covered natural gas distribution pipelines in all states and territories except Western Australia.

The NGL sets out the powers and functions of the AER in connection with access arrangements applicable to covered pipelines. The NGL also sets out the matters that the AER must consider and achieve when approving an access arrangement or making a substitute access arrangement. Specifically, the NGL requires the AER to perform its functions in a manner that contributes to the achievement of the National Gas Objective (NGO), which 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’.[3]

The NGL also requires the AER to consider specific revenue and pricing principles when exercising its discretion or making a determination.[4] Those principles provide important guidance not only to the AER and the gas sector but also to stakeholders who may want to engage in the consultation process associated with the AER’s process.

Our forecasts have all been prepared to ensure compliance with NGR requirements. This means that, amongst other factors:

- We have explained the basis of our forecasts.[5]
- Our forecasts are reasonable and are our best possible forecast given the circumstances.[6]
- Forecasts and inferences are supported by evidence.[7]

Marked-up revisions to the current access arrangement and other supporting documents have also been submitted to the AER along with this document.[8]

1.4. Composition of the proposed access arrangement

The current access arrangement comprises three parts:

[3] See Section 23 of the NGL.
[4] See Section 28(2) of the NGL.
[5] See Rule 74(1).
[6] See Rule 74(2).
[7] See Rule 75.
[8] In accordance with the definition of “full access arrangement” set out in the NGL, our proposed access arrangement is a full access arrangement as it: (1) provides for price regulation as required by the NGR for a network of covered pipelines; and (2) deals with all other matters for which the NGR requires provision to be made in an access arrangement.

- Part A sets out the principal arrangements and contains provisions relating to services policy, capacity management policy, queuing policy, extensions/expansions policy, and the dates for reviewing and revising the access arrangement.
- Part B sets out our Reference Tariffs and Reference Tariff Policy, and contains provisions relating to haulage reference tariffs, ancillary reference tariffs, tariff control formulae, procedures for variations to reference tariffs, new facilities investment, speculative investment fund, incentive mechanisms, fixed principles, and cost pass through arrangements.
- Part C sets out the terms and conditions under which distribution services are to be provided to network users.

The architecture and content of the current access arrangement was developed and approved in accordance with the National Third Party Access Code for Natural Gas Pipeline Systems (the National Gas Code). The access arrangement first came into effect on 1 January 1999, with subsequent revisions coming into effect on 1 January 2003, 1 January 2008, 1 July 2013 and 1 July 2018. The proposed revisions to the access arrangement will therefore be the sixth to apply to our gas distribution network in Victoria.

To minimise the changes to the current access arrangement, we are proposing to retain the three part structure for the forthcoming access arrangement period.

1.5. Overview of the regulatory framework

The NGL and the NGR set out the regulatory framework for gas pipelines. Under the NGL, the AER is responsible for the economic regulation of covered natural gas distribution pipelines in all states and territories except Western Australia.

The NGL sets out the powers and functions of the AER in connection with access arrangements applicable to covered pipelines. The NGL also sets out the matters that the AER must consider and achieve when approving an access arrangement or making a substitute access arrangement. Specifically, section 28(1) of the NGL requires the AER to perform or exercise its regulatory functions or powers in a manner that will or is likely to contribute to the achievement of the NGO. The NGO is set out in the NGL which states:

> *[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.*[9]

The NGL also requires the AER to take into account specific revenue and pricing principles when exercising its discretion or making a determination.[10] Those principles also provide guidance to us and other stakeholders who may be interested in participating in the consultation process associated with the forthcoming access arrangement.

In addition to meeting the requirements of the NGL and NGR, this document also refers to relevant NGL and NGR provisions where this will assist stakeholders in understanding our proposed revisions.

1.6. Overview of our gas business

Our gas network supplies affordable, safe and reliable energy to over 760,000 homes and businesses across western and central Victoria, including the outer-northern and north-west metropolitan areas of Melbourne and major population centres, such as Geelong, Ballarat and Bendigo. Approximately 4 in 5 households in our service area are connected to the gas network. As an essential service, the network has been built over decades with long term investments. These investments have been consistently made despite stable low returns because the capital recovery of efficient investment is guaranteed by customers through the regulatory regime.

The network transports natural gas from the principal gas transmission system, through 12,000 km of mains (pipelines) and hundreds of pressure regulating facilities (such as city gates and field regulators) to individual gas meters, which supply customers' appliances spanning a geographically diverse region of approximately 60,000 square kilometres.[11]

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[9] Section 23, NGL

[10] The revenue and pricing principles are set out in subsections 24(2) to (7) of the NGL.

[11] A description of the pipeline can be inspected at: https://www.ausnetservices.com.au/en/About/What-we-do (accessed 24/05/2022).

Figure 1.1: Gas distribution network

Source: AusNet

Our residential customer base is very diverse. We service many culturally and linguistically diverse customers—particularly in the northern and western suburbs of Melbourne. Other than English, Vietnamese and Arabic are the two most commonly spoken languages in our distribution area. Many key vulnerability markers are overrepresented in the postcodes we service, including the proportion of the population living in poverty.

Our business customer base is also very broad and almost all industries are represented. Our small and medium business customers typically use gas for the same things households do – a combination of space heating, hot water and cooking. We also know that many businesses, including cafes and restaurants, have a strong preference for cooking with gas rather than electricity. Our industrial customers use gas for a range of purposes, including for manufacturing food, textiles, chemicals and materials. In many cases, these customers have no or few alternatives to gas. Many can only use specific types of gases in their industrial processes.

Further information on our gas business is outlined in Chapter 2.

1.7. Structure of this document

The remainder of this document is structured as follows:

- Chapter 2 provides an overview of our gas distribution business.
- Chapter 3 considers the future of gas, given the energy sector is decarbonising, and the role our gas network will play in a net-zero emissions future remains unclear.
- Chapter 4 explains our gas demand and customer number forecasts for the forthcoming access arrangement period.
- Chapter 5 sets out information on our approach to customer engagement, the engagement activities undertaken, and the key feedback received from customers.
- Chapter 6 provides details of our capital expenditure forecasts for the forthcoming access arrangement period.

- Chapter 7 provides details of our operating expenditure forecasts for the forthcoming access arrangement period.
- Chapter 8 presents information on our capital base.
- Chapter 9 sets out our views on depreciation, including our approach to accelerated depreciation.
- Chapter 10 explains the rate of return.
- Chapter 11 sets out our proposed allowance for the cost of corporate income tax.
- Chapter 12 presents a summary of total revenue requirement.
- Chapter 13 sets out our proposed pass through arrangements.
- Chapter 14 outlines the incentives we are proposing to apply.
- Chapter 15 describes the reference services for the forthcoming access arrangement period.
- Chapter 16 details the proposed price control mechanisms.
- Chapter 17 sets out information on our reference tariffs.
- Chapter 18 explains the rationale for the proposed changes to Part C of our terms and conditions.
- Chapter 19 outlines the fixed principles we are proposing will apply.
- Chapter 20 provides information on other matters, including queuing policy, capacity trading policy, and extension and expansion policy.

2. Overview of the gas business

2.1. Key points

- The domestic gas market is facing longer term challenges as the Australian economy decarbonises. This includes a shift from coal to renewables, potentially without the transitional step of using gas fired generation. In addition, there are more immediate influences that are tending to drive lower gas consumption.
- Our purpose is to 'Connect communities with energy and accelerate a sustainable future' and we will achieve this by (amongst other things) operating a network that will adapt and respond as Victoria moves toward a renewable energy future.
- We are continuing to invest in the capacity and integrity of the network by replacing old mains with modern polyethylene pipes, which are capable of carrying hydrogen should the need arise.
- We deliver our services as efficiently as possible, including through competitively sourced contracts with third party service providers.

2.2. Chapter structure

The remainder of this chapter is structured:

- Section 2.3 provides an overview of the market challenges facing the domestic gas market.
- Section 2.4 describes our vision and objectives for the gas distribution network.
- Section 2.5 provides information on our gas network.
- Section 2.6 outlines our service delivery model.
- Section 2.7 provides a brief description of how we monitor the performance of the gas distribution network.

2.3. Gas market challenges

The domestic gas market is facing several challenges that will impact its longer term future as the future of gas is affected by the decarbonisation of the Australian economy. These issues are discussed in Chapter 3. In the near term, the following factors will moderate gas consumption.

- Gas to electric appliance switching.
- Building design and choices.
- Potential increase in prices.

While these matters are discussed in detail in Chapter 4 (Demand), it is useful to comment on each briefly to provide background to this proposal.

2.3.1. Gas to electric appliance switching

A key driver of the moderation of this is 'gas to electric appliance switching', which was outlined by the Australian Energy Market Operator (AEMO) in its 2021 Gas Statement of Opportunities (GSOO).[12] The key trend is that more and more households are installing reverse cycle air-conditioners to heat their homes, which costs one-third as much as ducted gas heating. This reduces the extent to which households may want to connect to gas (for the purposes of space heating).

[12] AEMO, Gas Statement of Opportunities. p. 24. See: https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2021/2021-gas-statement-of-opportunities.pdf?la=en#:~:text=In%20the%202021%20Gas%20Statement,Australian%20gas%20systems%20to%202040 (accessed 15/02/2022).

Reverse-cycle air conditioners are typically more energy efficient than gas heaters. Across the National Electricity Market around half of households have a reverse cycle air-conditioner installed.[13] This is resulting in lower usage per customer.

2.3.2. Building design and choices

In addition to appliance switching, an increasing number of households, particularly those in flats, are moving into all-electric home with energy-efficient equipment. In addition, new buildings often have superior insulation, thus requiring less heating, and they (together with renovated buildings) tend to have more energy-efficient appliances.

Whole 'sustainable' suburbs are also springing up that will have no connection to gas. This often reflects the tapping in to zero-emission technologies such as rooftop solar panels and reverse cycle air-conditioners.

More broadly, government incentives and lowering costs have also led to more installation of rooftop solar, and energy corporations to invest extensively in renewables — first wind, then solar – displacing gas even further.[14]

2.3.3. Gas prices are expected to increase

Another factor affecting penetration rates is that gas prices are expected to increase.

The east coast has already burned most of its low-cost gas, and will not go back to low prices, so gas will become an increasingly expensive energy source. Gas is expected to become more expensive in Eastern Australia, and the impact will be felt by manufacturers and power generators, by small businesses and households.

If households and developers have anticipated these changes and have factored them into their decisions over whether to connect or disconnect from the gas network, this would tend to reduce marginal penetration rates.

Even in Victoria, with its emissions-intensive brown coal power generators, electricity is likely to be cleaner than natural gas by 2035.[15]

2.4. Vision and objectives

We operate in a dynamic environment, characterised by the challenges described above, along with regulatory changes, technology advancements and shifting customer behaviours and values relating to their energy usage.

Within this ever changing environment our purpose is simple: Connect communities with energy and accelerate a sustainable future.

Our strategy enables us to continue providing safe, reliable and affordable energy to our customers. We're growing our business to create long-term value for our customers, communities and investors. We understand the role we play in the transition to renewable energy. Through our strategy, we will own and operate a network that will adapt and respond as Victoria moves toward a renewable energy future.

2.4.1. Corporate values

A purpose, strategy, and aspiration, on their own, are not sufficient to define how the business will achieve company goals. We also need values to express what we stand for and guide the way we do things. We have four company values, and these values guide the actions of all our people, every day.

- **We work safely**: We never compromise on safety and we care for the wellbeing of people.[16]
- **We do what's right**: We act with integrity and in the best interests of our company and our customers.
- **We're one team**: We work together as a united team to achieve great results. We treat our people fairly, value their differences and support their development.
- **We deliver**: We're accountable to customers, communities, shareholders and each other. We adapt through innovation, continuous improvement and change.

[13] CIE, 2023 - 2028 GAAR Demand, Energy and Customer Forecast, pp. 25- 27.
[14] CIE, 2023 - 2028 GAAR Demand, Energy and Customer Forecast, pp. 25 -27.
[15] CIE, 2023 - 2028 GAAR Demand, Energy and Customer Forecast, p. 26.
[16] A key component of this is our safety vision: "Safety is our way of life. Everyone is responsible for leading safety. Together we seek out and correct all unsafe behaviours and situations and aim for zero injuries." Our safety vision is symbolised by the simple expression missionZero. When it comes to the safety of our people, contractors and visitors, zero injuries is the only acceptable target. We will not compromise on safety and we will not tolerate unsafe acts and behaviours. It is this mindset that drives us to ensure there are no negative impacts on our families and communities as a result of our business operations. To achieve our safety vision, our mission is to work together to implement a common strategy with unified purpose and consistency of attitude.

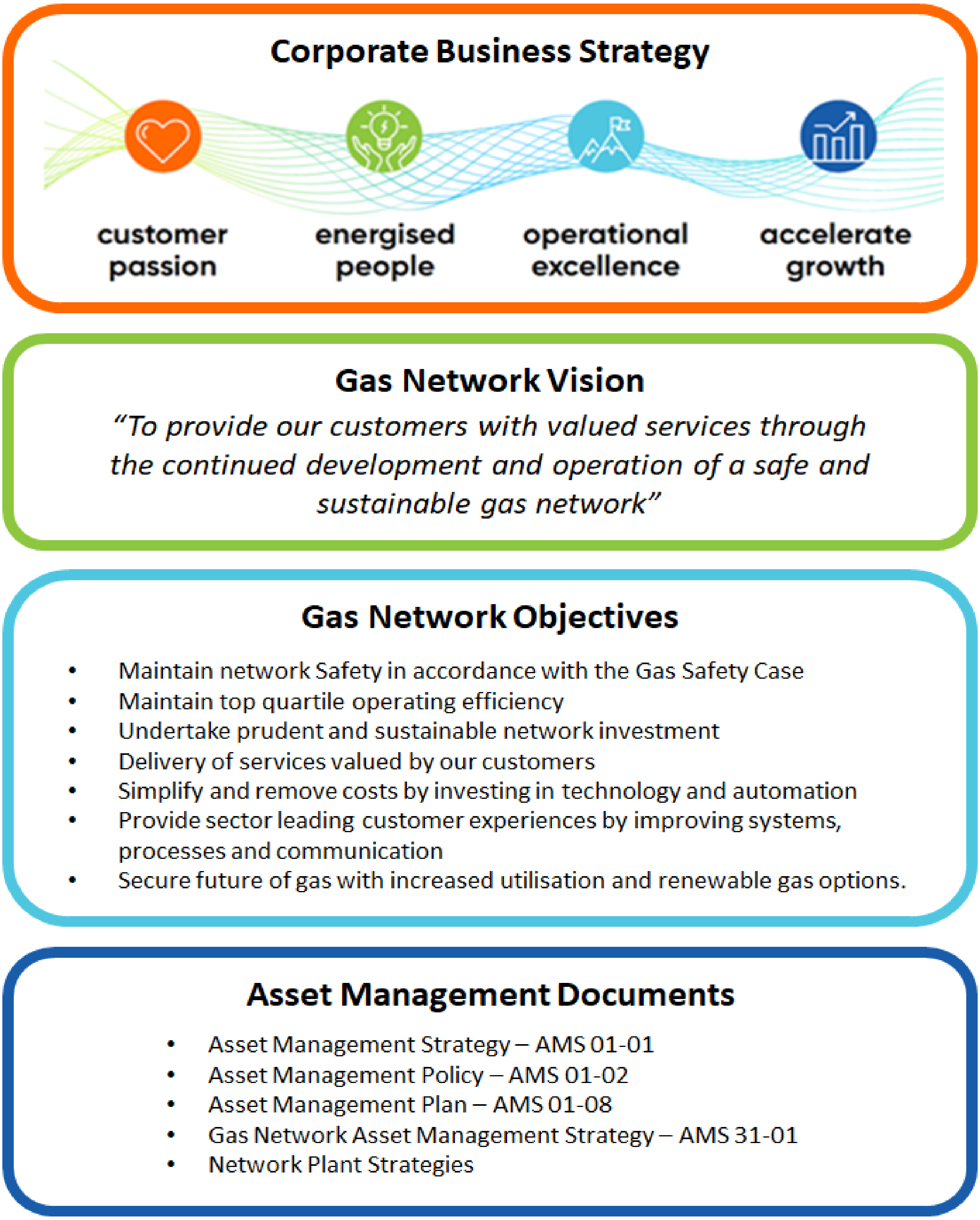
2.4.2. Delivering while meeting our regulatory obligations

We balance the cost of increased expenditure against network performance and customer satisfaction in both the short and long-term. However, we must also meet our regulatory obligations set out in our Gas Safety Case (consistent with the Gas Safety Act and Gas Safety Regulations) and the Gas Distribution System Code.

The expenditure plans for the forthcoming access period are consistent with our regulatory obligations and our vision and objectives for the gas network. We seek to satisfy our regulatory obligations while delivering on our vision and objectives for the network at stable (and competitive) prices for our customers.

The figure below shows how all these business drivers link together.

Figure 2.1: Values, vision and objectives all centre around our customers



Source: AusNet

2.5. The gas distribution network

Our gas network, which has been constructed over a period of more than 100 years, distributes natural gas from the principal gas transmission system to individual gas meters, which supply customers' appliances. In total, gas is supplied to approximately 763,000 customers across the west of Victoria, including the outer northern and north-west metropolitan area of Melbourne.

The network consists of over 12,000 km of mains (pipelines) and hundreds of pressure regulating facilities (such as city gates and field regulators) spanning a geographically diverse region of approximately 60,000 square kilometres (see Chapter 1, section 1.6 for more information). We also own a liquefied petroleum gas vapour reticulation network at Mount Baw Baw, which is not the subject of this access arrangement proposal.

At present, the network contains some of the fastest growing urban and regional locations in Victoria. Within the Melbourne metropolitan area, the number of occupied dwellings in Wyndham and Melton have grown at 30% and 23% respectively over the past five years. In regional Victoria, our gas distribution network covers major population centres such as Geelong, Ballarat and Bendigo. In addition, regional Local Government Areas exhibiting strong growth such as Moorabool, Golden Plains, Macedon Ranges and Surf Coast are all located in our network.

The gas demand profile of the network is winter peaking, with a pronounced spike arising from the increased customer take-up of domestic heating. Management of the gas peak demand is, accordingly, an important consideration in the management of the network.

Most of the distribution system operates at high pressure with a minimum allowable pressure of 140 kPa to a maximum of 515 kPa. 'City gates' regulate supply from the transmission system (owned and operated by APA Group) to our distribution network.

The medium pressure distribution systems operate between 15 kPa to 140 kPa, with field regulators controlling gas supply from our high pressure networks. The low pressure distribution systems operate up to 7 kPa with district regulators controlling gas supply from our high and medium pressure networks. Pipeline corrosion is managed by installing corrosion protections units (CPUs) and sacrificial anode beds.

Meter and regulator assemblies, which vary from large industrial or commercial units to small domestic units, supply gas to consumers. A meter and regulator setup is provided for each supply point (i.e., customer connection) from the distribution network.

We use a SCADA (Supervisory Control and Data Acquisition) system to monitor and control assets across the network from the transmission system to the network fringe. The SCADA system provides data on the real-time performance of the assets, and data for long-term evaluation of gas demand and network performance to identify potential system deficiencies. The SCADA system is made up of Remote Telemetry Units (RTUs), a radio and telephone communications system, and a host computer system supporting the Network Operations Centre, which operates 24 hours a day, 365 days a year.

Given the age of our network a variety of pipeline materials, with varying performance capabilities, have been used over time. Cast iron and steel was predominantly used until the introduction of polyvinyl chloride (PVC) for low pressure like-for-like replacement and polyethylene for high pressure networks in the late 1970s. Today, polyethylene is the material of choice for pipe renewals (see table below).

The type of material dictates the maximum operating pressure and affects the overall performance of the network. Since cast iron can only be operated at medium and low pressures compared to polyethylene, the continuing replacement of cast iron mains with polyethylene pipe enhances the capacity and integrity of the network, helping to offset some of the natural age-related deterioration. Polyethylene materials also deliver significant safety benefits over the ageing cast iron assets.

Table 2.1: Pipe material summary and performance capability

Material	Description	Length
Polyethylene (PE)	Polyethylene mains, introduced in the 1970s, account for more than 50% of the total distribution mains in the network. It can operate at high pressure and is not susceptible to corrosion.	9,335 km
Protected Steel	Coated steel using both screwed and welded jointing are dependent on the corrosion protection coating. The coatings are regarded as having an effectively indefinite life. The effective life of this piping system is determined by the faults in the corrosion protection coating.	2,496 km

Poly Vinyl Chloride (PVC)	PVC was used extensively from 1970 to 1997 in the replacement of cast iron mains in the 'like for like' mains replacement program adopted at the time. PVC is only rated for operation at low pressure.	236 km
Un-Protected Steel	This piping system is based on bare steel and galvanised iron pipes that have been joined by having threads cut into the ends and screwed into joining couplings. Galvanising has considerably reduced effectiveness in reducing corrosion when buried.	235 km
Cast Iron	Cast irons generally contain more than 2% carbon and are categorised into the two types for the purpose of engineering life analysis; lead jointed and mechanical jointed.	73 km

Source: AusNet

The table below provides a summary of our gas distribution network in terms of pipeline pressure and material.

Table 2.2: Length of mains per pressure tier (km, as at end of 2021)

Material	Low Pressure	Medium Pressure	High Pressure 1	High Pressure 2	Total
Cast Iron	72.4	0.5	0.2	-	73.0
PVC	265.3	-	0.2	-	236.0
PE	9.7	221.0	9042.1	62.5	9334.9
Un-Protected Steel	10.7	197.6	0.7	-	234.6
Protected Steel	6.6	196.4	2258.6	34.9	2496.5

Source: AusNet

2.6. Service delivery model

The core functions associated with our ownership and operation of our gas network are:

- Asset Management.
- Service Delivery Management.
- Customer Management.
- Corporate Services.
- Strategy.

These functions are performed in-house.

Operation and maintenance (including minor capital works) and major capital projects are delivered by external service providers.

2.6.1. In-house functions

The table below describes the core functions that are undertaken in-house (through our internal resources).

Table 2.3: The core functions performed internally

Business area	Function
Network management	Compliance Strategy Asset Maintenance & Replacement Strategy Network Planning & Development Network Information Management (Strategy & Analysis) Development of Asset Management Plans & Work Programs Development of Asset Policies, Standards & Technical Bulletins
Service delivery management	Management of interface with Service Providers for network services Monitoring of Service Providers operational compliance Performance Management Large Capital Project Management Health Safety & Environment (HS&E) Oversight Audit
Network control centre	Manning of a 24hr / 7 day a week Network Control Centre Provision of 24 hr / 7 day a week Dispatch Function Support & Maintenance of SCADA Real Time Systems
Customer and market management	Revenue & Tariff Management Retailer / Customer Connection Management Key Customer/Stakeholder Relationship Management
ICT services	ICT Strategy ICT Architecture & Planning Asset Management Platforms
Corporate services	Regulatory Management Regulatory Accounting Financial & Management Reporting Treasury Settlements Corporate Affairs Internal Audit Accounting including Cash Management & Transaction Processing Property Management

Source: AusNet

2.6.2. Operations and maintenance contract

In 2019, our initial five-year contract with Downer for operations, maintenance and minor capital was extended for another five years. Commencing in April 2021, the contract extension will see Downer continue to provide operations, maintenance, capital works and 24/7 emergency response for our gas distribution network. [17]

The structure of the agreement aligns the contractor with our incentives to seek continual improvements in network and operational performance.

2.6.3. Major capital works

Major capital works projects are awarded to successful applicants pursuant to our Installation Service Provider or capital works agreement.

[17] See: https://www.australianmining.com.au/oil-gas/downer-extends-gas-contract-with-ausnet-for-350m/ (accessed 14/02/2022).

Each Installation Service Provider Panel member is selected based on an assessment process where their safety, competitiveness, quality, delivery record and financial viability are assessed, (noting that their ongoing performance against these variables determines whether their term on the panel is extended). Individual projects are periodically released to the panel members, who are invited to bid competitively.

Following an appraisal and approval process, the works are awarded to the successful panel member. Projects are typically negotiated to be delivered within a set timeframe and are subject to fixed price agreements to transfer price risk to the service provider.

By using this approach, we can focus internal resources on the core functions of project planning, overall project delivery and contract management. This contracting approach benefits both us and customers by:

- Appropriately balancing the use of internal and external resources.
- Utilising market expertise and intellectual property.
- Securing lower prices by requiring panel members to compete for work.
- Obtaining economies of scale by ensuring that panel members expect to deliver appropriate volumes of work.
- Ensuring high quality and timely project delivery through effective monitoring of performance.

2.7. Performance of the gas network

We have several objectives and key performance indicators (KPIs) to measure the success of our gas network. These are reviewed on an annual basis to ensure they are the most relevant indicator of performance. We also report the outcomes of these KPIs to both the ESV and the AER on a monthly basis.[18]

Network objectives and KPIs we have been pursuing in the current access arrangement period include:

Maintaining network safety in accordance with the Gas Safety Case

a) Continuation of our mains replacement program (nothing that we are proposing to complete our low-pressure mains replacement program as part of our capital expenditure proposal).

b) Mains Leakage rate by pressure tier.

c) Network Leaks – 12 Month Rolling Average.

d) Third Party Damages on Mains and Services.

e) Recordable Injury Frequency Rate.

Undertaking prudent and sustainable network investment

a) Capital performance.

b) Unaccounted for gas (UAFG).

[18] The AER produces gas network performance reports and these reports set out the AER's analysis of key outcomes and trends in the operational and financial performance data it collects from the six fully regulated gas distribution networks in New South Wales, Victoria, South Australia and the Australian Capital Territory. The 2021 report is available at: https://www.aer.gov.au/networks-pipelines/performance-reporting/gas-network-performance-report-2021 (accessed 23/02/2022).

Delivering valued services to our customers

a) Unplanned Supply Average Interruption Duration Index (USAIDI) - this represents the average outage duration for each customer. The gas network is inherently reliable and this measure is primarily influenced by rainfall.

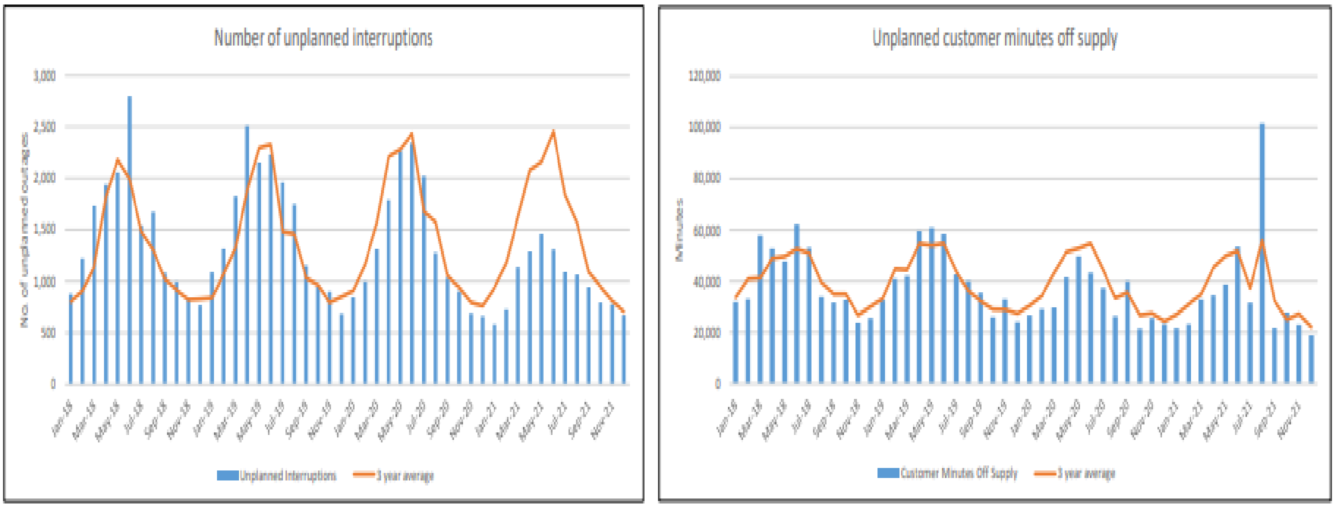
b) Emergency Response Times – this is a core reactive safety indicator, where the benchmark is set by Energy Safe Victoria (ESV).

c) Asset Cost per customer – the aim here is to maintain low cost per customer.

d) Number of customer complaints – we expect continuous decrease of customer complaints.

Our prudent and efficient investment over the current regulatory has ensured a robust performance against all our KPIs and this is illustrated if two of these indicators – Interruptions and unplanned minutes of supply – which can be seen in the figures below. Importantly, these KPIs provide visibility on a 12 month rolling basis.

Figure 2.2: Interruptions and unplanned minutes of supply.[19]



Source: AusNet

Both these KPIs provide visibility on a 12 month rolling basis and show (amongst other issues) that our investment in the network, including our mains replacement program, has contributed to the long-term improvements in both the number of unplanned interruptions experienced by our customers and the minutes of supply. in the next access arrangement period, we are proposing (amongst other issues) to continue our investment in our mains replacement program (see Chapter 6) and this, along with other aspects of our proposal, will help us meet, if not improve our performance over the forthcoming access arrangement period.

[19] These charts were taken from our December 2021 monthly KPI dashboard.

3. Future of gas

3.1. Key points

- Delivering safe and reliable energy to our customers requires that we invest in our network and, in exchange, we are provided an assurance that we can recover the efficient cost of that investment (over the life of those assets). This concept is known as the regulatory compact and it is fundamental to our ongoing ability to deliver safe and reliable gas supply for our customers over the long-term.
- Given the recent emphasis on emission reductions, including the Victorian Government's legislation for net-zero emissions by 2050 (and targets to reduce emissions by 2025 and 2030), the role of gas networks in the long term is uncertain.
- To help determine how the future of gas may unfold, and therefore how we should shape our proposal, we invited an Expert Panel to develop future scenarios.
- Recognising the uncertainty of the gas network, the role of the regulatory compact, and the need to minimise price impacts over the longer term, we are proposing to accelerate the speed at which we recover the efficient cost of our investment. This is known as accelerated depreciation. We propose to adopt this approach and apply $150 million of accelerated depreciation in the next access arrangement period.
- While accelerated depreciation increases prices in the short term, it lowers prices in the longer term. Importantly, lower future prices are key to assisting the gas network to remain competitive if we transition to a hydrogen network or, where the gas network needs to be wound down, it assists in keeping keep prices lower for remaining customers as demand reduces across the network. Importantly, it also lowers the risk to our investors that they will not be able to recover all the investments that they make in our gas network.
- Our proposal does not incorporate a response to the Victorian Government's Gas Substitution Roadmap (the Roadmap). The Roadmap was not released at the time our proposal was submitted to the AER. Engaging with and reflecting on the implications of the Roadmap is expected to be a key part of our post lodgement engagement activities. If the Roadmap is delayed, then how we best address the continued policy uncertainty will be a key part of our post lodgement engagement activity.
- We have engaged extensively with our customer stakeholder group on the issues addressed in our proposal, including on the impacts of the scenarios developed by the Expert Panel, how we developed our forecasts (including accelerated depreciation) and our response to the Victorian Government's interim modelling developed for the Roadmap.

3.2. Chapter structure

The remainder of this chapter is structured:

- Section 3.3 outlines the operating environment we must operate within.
- Section 3.4 provides information on the Expert Panel we engaged to develop scenarios to help us develop our proposal.
- Section 3.5 explains how, drawing, on the scenarios developed by the Expert Panel, we undertook additional modelling to develop our proposal.
- Section 3.6 explores depreciation, including the use of accelerated depreciation, to address the uncertain future we find ourselves and to eliminate potentially significant price increases for gas customers that remain on our network.
- Section 3.7 summarises the customer engagement undertaken on the future of gas.
- Section 3.8 provides information of the Victorian Government's interim gas substitution roadmap modelling and explains why we have not reflected this interim modelling in this proposal.
- Section 3.9 provides information on where additional information associated with this chapter can be found.

3.3. Operating environment

The Victorian Government has legislated a long-term target for Victoria of net-zero greenhouse gas emissions by 2050. In the Climate Change Act 2017 (Vic), the Victorian Government commits to supporting communities and businesses through the transition to reduce the impacts of climate change and help support growth in the economy. The Victorian Government has also set targets to reduce Victoria's greenhouse gas emissions from 2005 levels by 28–33% by 2025 and 45–50% by 2030.

While it is more environmentally friendly to use gas than non-renewable electricity from the electricity grid, natural gas accounts for approximately 13% of Victoria's annual emissions. That said, we know our customers value gas, and would prefer using it (over the long-term) if there is an affordable and safe zero emissions option. Decarbonising the gas sector can be achieved through two primary pathways – introduction of renewable gas or electrification. The first pathway involves replacing natural gas with renewable gases like hydrogen that, when burnt, do not release greenhouse gases. The second pathway involves making electricity generation 100% renewable and shifting the energy supplied by the gas network to the electricity network and decommissioning some/all of the gas network.

The key question facing gas networks is what proportion of the energy needs that are currently met by natural gas will be (or can be) met by renewable electricity or renewable gases like hydrogen in the future.

While we engaged an Expert Panel to develop four scenarios which considered different levels of renewable gas adoption (see section 3.6), we have outlined below some of the key benefits and implications of the use of hydrogen and electrification. We have also provided some information on the Roadmap, which could play a significant role in shaping the future of gas.

Regardless of the actual path to net zero, this means major long-term changes for our network. However, it is also important to understand that under any scenario, the community will require a safe and reliable gas distribution service in some form up to 2050, and likely beyond. We must, therefore, manage and invest in our gas network accordingly.

3.3.1. Benefits and implications widespread adoption of hydrogen

Our customers have told us they value a gas connection and would prefer to keep using it if a renewable option is available. Widespread use of hydrogen represents such an option and its use could help:

- Keep overall energy costs lower.
- Provide customers a choice as to their preferred fuel.
- Keep the gas network operating to utilise the significant sunk investment made by the customers (or, alternatively, avoid the significant cost associated with the winding down and decommissioning of our gas network).
- Ensure we achieve an appropriate return on our sunk (gas) investment.

Using hydrogen could also help maintain a gas supply for industrial consumers that cannot feasibly transition to electricity (particularly high heat industrial processes), meaning they remain in operation, rather than close.

The use of hydrogen could also avoid the significant costs that are likely to be incurred:

- By gas customers, who will need to buy new electric appliances if they move to an all-electric home/business.
- By all electricity customers, as the electricity system will need to be strengthened to allow more electricity to be safely and reliably moved across an electricity network that was designed on the basis that a gas network was also in operation.

Specifically, by having a hydrogen future these costs could be avoided, or largely mitigated. And, in an environment where there are increasing cost pressures, we expect this to be a particularly important issue that will need careful consideration.

Hydrogen can also be readily stored (including in transmission pipelines if they are not decommissioned) and thereby supports energy system resilience (both in terms of security and reliability). For example, the continued operation of our gas network, retaining dual energy supply systems, will provide greater resilience to the Victorian community, particularly given the increasing trend of severe weather conditions that contribute to electricity blackouts. The ability to store gas will also become an increasingly important consideration as the energy demand from transport sector transitions to the electricity.

If the gas network is decommissioned (and complete electrification occurs), networks and customers may face several other major challenges. These will need to be carefully considered by networks and policy makers and include:

- How to progressively shut down the gas network and remove connected customers. For example, this could be done on a segment (geographic region) by segment approach according to a publicised timeline, or organically as demand falls and customers switch to electricity supply. However, if this implemented, shutting down the network will require careful coordination of government, gas distributors, appliance manufacturers and trades to minimise costs to consumers, as gas networks cannot be decommissioned until all customers in a segment have disconnected from the gas network.[20]

- How best to allow gas network businesses to recover the sunk capital asset base values from a declining customer base as networks are wound down and progressively decommissioned.
- Regulatory amendments to allow the gas networks to operate safely while being progressively shut down.
- How to fund and deliver the augmentations to electricity transmission and distribution networks necessary to meet the additional load that was previously met by the gas networks. The cost of this could be significant.

Given the magnitude of the challenges outlined above, there is a compelling reason to keep the option of a hydrogen transition open.

3.3.2. Benefits and implications of widespread adoption of electrification

Widespread electrification also has several potential large benefits. The key benefits associated with greater electrification is that it involves a relatively straightforward (known and feasible) but not necessarily cheaper transition path. There appears to be a clear ability to electrify the domestic gas load, subject to significant augmentation of the electricity system. However, we also recognise that some commercial and industrial customers may not be able to transition to electricity easily or cost-effectively.

We also know that hydrogen production is currently relatively expensive and widespread delivery and usage of Hydrogen is unproven. It is, therefore, plausible (but not certain) that established electricity networks may end up being the overall cheaper energy delivery mechanism, which would allow a consolidation of the energy delivery mechanisms into a single grid system.

3.3.3. Victorian Government's Gas Substitution Roadmap

The Victorian Government is exploring sustainable alternatives and pathways for the gas sector to transition to net zero emissions and is developing a Roadmap to provide a strategic framework for decarbonising natural gas in Victoria. [21]

The Roadmap is expected to detail the transition pathways and identify policy mechanisms to achieve Victoria's emissions reduction targets through reduced fugitive emissions, more efficient use of natural gas, electrification and increased use of alternative gases such as hydrogen and biogas. [22] However, it has not yet been released and so we have been unable to incorporate it in our access arrangement proposal.

Prior to the Roadmap's expected publication, the Government shared the outcomes of interim modelling it had commissioned as an input to the development of the Roadmap. The interim modelling considered three scenarios plus a baseline 'no action' scenario. Excluding the baseline scenario, the key assumptions adopted in the three scenarios prepared were (amongst other factors):

- A 50% reduction in residential and commercial gas usage and a 30% reduction in industrial usage by 2030.
- Reductions will come by switching to a combination of electrification, energy efficiency and biomethane (with some very limited hydrogen pre-2030).
- A viable pathway for hydrogen is only available after 2040.

The Government's interim modelling does not reflect Victorian Government policy. However, if one or more of these assumptions were adopted by Government, it would have significant implications the Victorian gas network businesses.

If there are policy changes prior to the completion of the current access arrangement review process, substantial amendments to our access arrangement proposal (including demand, accelerated depreciation and prices) may be required. While our strong preference (and the AER's expectation) is always to engage in comprehensive customer engagement, given the timeframes outlined in the NGR, our ability to do has been limited to discussions around hypothetical outcomes. That challenge notwithstanding, we will continue to look for opportunities to maximise the scope for additional engagement. We also note we will continue to engage with the Victorian Government on the Roadmap and associated issues to ensure the implications of any potential policies are considered.

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[20] Where this occurs, customers are likely to remove their gas appliances and instal electric equivalents.
[21] More information about the Roadmap is available at https://engage.vic.gov.au/help-us-build-victorias-gas-substitution-roadmap.
[22] https://engage.vic.gov.au/help-us-build-victorias-gas-substitution-roadmap (accessed 22/03/2022).

3.4. The regulatory compact, asset stranding and accelerated depreciation

A gas distribution service is a natural monopoly and is regulated to ensure that the price and reliability of the services provided are in the long term interests of consumers. While aspects of the regulatory framework seek to mimic competitive outcomes, there are important elements that are unique to monopoly essential service regulation. In stark contrast to a firm operating in a competitive market, a regulated monopoly is compelled to invest in long-lived assets at low rates of return. For example:

- We are required to connect new customers at the regulated price.[23] In contrast, a competitive firm can refuse to accept new customers after its own assessment of risk.
- Network planning standards set out minimum pressures to be maintained requiring us to augment the system to meet those standards. A competitive firm can could choose to lower standards (provide poor gas pressure at peak times), particularly if it is unlikely to be able to recover the cost of its investment. We must invest and we must maintain standards.
- Safety legislation (appropriately) requires we invest to maintain system integrity so as to minimise safety risk on the existing gas system. While a competitive firm would also have to maintain these safety standards, it has the freedom to choose to decommission or cease service if the cost of investment was not be recoverable.

Consistent failure to meet our regulatory obligations can ultimately result in our licence being revoked and substantial financial losses as the current owners would lose control of the assets.

At face value, undertaking substantial investment with long recovery periods is very high risk and would normally require commensurate risk-based returns to attract the necessary funding. In this environment, customers would be paying very high prices to compensate the service provider for this risk. To avoid high prices, the Government, through its legislated regulatory framework, creates a 'regulatory compact' with the regulated monopoly, on behalf of customers and the community, that guarantees the recovery of prudent and efficient investment provided certain criteria are met. It follows that the regulatory compact places stranded asset risk on customers in the first instance, backstopped by the Government if necessary.

In this context, we continue to make large investments in network assets that deliver long-term benefits to consumers at very low rates of return in reliance on the fact that the regulatory framework allows us to fully recover the efficient cost of those investments. We are also proposing prudent, well-balanced steps to reduce the increased stranding risks associated with uncertainty over the future of gas. In particular, we are proposing to use accelerated depreciation to help recover some of our costs earlier than would otherwise be the case. Importantly, we are not seeking to place the entire stranding risk on our customers. Rather, we are prudently seeking to reduce this risk at a time when the price impact on customers is the lowest. If we are not permitted to take reasonable steps to reduce the risk of asset stranding (which any competitive firm would do), our ability to respond to these risks is unfairly restricted and the regulatory compact is undermined.

As part of our engagement process, stakeholders have queried whether we should bear the totality of the asset stranding risk due and whether we should be permitted to take steps to reduce the risk that we are bearing e.g. by proposing accelerated depreciation. As outlined above, the regulatory regime provides for this risk to be placed on customers as our ability to reduce/cease investment or fundamentally modify the services or prices we offer is constrained by the Government. Nonetheless, we are weighing the impact on our customers and where we have discretion and to the extent that we are able, proposing prudent steps to minimise this risk while maintaining affordability. This is the best outcome we can achieve within the framework we must operate within.

Regulators around the world have started considering the implications of the stranding risk on gas networks and, in recognition of the regulatory compact, some have been making changes to either the regulated rate of return (see Chapter 9) or depreciation schedules (see Chapter 10) to allow for sunk investment costs to be recovered. For example, Austria, Belgium, Netherlands and the UK have all accelerated depreciation to bring forward recovery of assets.[24] The New Zealand Government Gas Infrastructure Future Working Group on these issues stated:

> *By design, economic regulation affects the incentives faced by gas transmission and distribution infrastructure businesses. Core to the economic regulation framework is a 'regulatory compact', whereby regulated businesses invest in their networks with the expectation that they will be able to recover from consumers the costs of efficient investment that is in their long-term interests. In return for a high level of certainty of returns, economic regulation limits the rate of return that can be achieved.*[25]

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[23] Gas Distribution System Code of Practice, clause 3(a) and (c).

[24] Please see: https://www.aer.gov.au/system/files/Jemena%20-%20Submission%20-%20Equity%20-%203%20September%202021%20-%20Attachment%202%20-%20NERA%20Stranding%20Risk%20Report.pdf, p. 27.

[25] Future Working Group, *NZ Gas Infrastructure Future Findings Report*, 13 August 2021, p. 49.

The AER has clearly articulated these same issues in its paper on regulating gas pipelines under uncertainty, stating:

- The national gas regulatory framework in the NGL and NGR essentially provides that, in exchange for supplying safe and reliable gas network services to customers at a reasonable cost, regulated gas businesses should be provided with, amongst other things:
  - A reasonable opportunity to recover at least the efficient costs the service providers incur in providing reference services (gas pipeline services).
  - Effective incentives to promote economic efficiency with respect to reference services the service provider provides.
  - A return commensurate with the regulatory and commercial risks involved in providing the reference services. [26]

If stranded asset risk is demonstrated to be material, the AER has noted that there are two primary ways to restore a reasonable expectation of cost recovery:

- Remove, or substantially reduce, the prospect of under-recovery of costs, or
- Compensate the regulated business for carrying this risk.[27]

The AER concluded that it is more appropriate to adopt the former approach (accelerated depreciation):

> *We have not provided any compensation to regulated businesses for stranded asset risk via the return on capital. This is because stranded asset risk is generally considered non-systematic. In addition, it has not been considered material to date. We consider that adjusting regulatory depreciation (return of capital), one of the building blocks we use to determine gas access prices, would be more appropriate to manage stranded asset risk under the regulatory regime.* [28]

We agree with the AER's analysis. An appropriate approach to restore a reasonable expectation of cost recovery is to substantially reduce the prospect of under recovery of costs. We also agree with the AER that by providing a network business a reasonable opportunity to recover at least the efficient costs they incur in providing services does not mean gas consumers must guarantee that the regulated businesses recover their costs under any circumstances. That is, a network business can still bear some asset stranding risk on inefficient or discretionary expenditure.

Our gas network currently has an opening regulated capital base of $1,799.7 million. Depending on what pathway to net zero is followed, significant stranding risks could emerge by 2040 at which time we will likely still have a capital base of over $1 billion. To help mitigate stranding risk we are, therefore, proposing to use accelerated depreciation to help recover some of our costs earlier than would otherwise be the case.[29]

The use of accelerated depreciation:

(1) Reduces the risk of us under-recovering our costs.

(2) Reduces the future sunk cost of the gas network, which:

   (a) Assists the gas networks being competitive in the future, increasing the probability that a switch to a hydrogen network will be achievable.

   (b) If the network cannot make a transition to hydrogen, reduces price pressures on customers who may find it difficult to switch away from the gas network.

Despite us proposing to use accelerated depreciation, we recognise that we may end up in a situation where customers will be unable to pay for the capital base as too many will have left the network, leading to exponential price increases. In these circumstances, Government intervention will be the appropriate mechanism to ensure recovery of our capital base and mitigate price impacts on customers who cannot leave the network.

We note the example of the Esperance Gas Distribution Company in Western Australia, which announced in September 2021 that it would surrender its trading licence and would no longer be supplying gas to the 379 homes and businesses connected to its network. The West Australia Government has subsequently negotiated an agreement to secure an additional 12 months of reticulated gas supply for these customers.[30] Within that context,

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[26] https://www.aer.gov.au/system/files/AER%20Information%20Paper%20-%20Regulating%20gas%20pipelines%20under%20uncertainty%20-%2015%20November%202021.pdf (accessed 16/05/2022).
[27] https://www.aer.gov.au/system/files/AER%20Information%20Paper%20-%20Regulating%20gas%20pipelines%20under%20uncertainty%20-%2015%20November%202021.pdf (accessed 16/05/2022).
[28] https://www.aer.gov.au/system/files/AER%20Information%20Paper%20-%20Regulating%20gas%20pipelines%20under%20uncertainty%20-%2015%20November%202021.pdf (accessed 16/05/2022).
[29] As noted earlier, we are not seeking to place the entire stranding risk on our customers. Rather, we are prudently seeking to reduce this risk at a time when the price impact on customers is the lowest.
[30] https://www.mediastatements.wa.gov.au/Pages/McGowan/2022/02/Continued-energy-supply-for-Esperance-homes-and-businesses.aspx (accessed 16/05/2022).

trying to take modest steps now, to prevent or at least minimise the need for Government intervention later, is appropriate.

3.5. Stakeholder and customer engagement

As part of our proposal development we, together with the Australian Gas Industry Group (AGIG), undertook significant engagement with our customers and stakeholder, including on how to address the uncertain nature of the Future of Gas. While our engagement activities are outlined in Chapter 5, this included drawing on an Expert Panel, stakeholder groups and end use customers.

A key part of this engagement was developing models to examine possible futures for the gas networks. Given the complexity of the issues and the novel nature of the modelling task we have undertaken, we have been very open with stakeholders throughout this process, including sharing preliminary results from our models. Stakeholders were very supportive of the open and extensive nature of our engagement.

While we have presented summary outputs from our models, we have not, prior to submission, made the models public or provided details of the sensitivity of the model to key assumptions. This was appropriate as we were developing both our models and approach. However, as we have now finalised our models, we have made all this information available to our stakeholders as these models form part of this proposal.

Stakeholders provided very clear feedback during our development and consultation on our models:

- There is widespread acknowledgement that we are in a complex operating environment, and stakeholders have a very keen interest in how we respond to the uncertainty around gas networks' role in a net zero emissions future. There is widespread frustration at the absence of clear policy from state and federal governments.
- Stakeholders understand the divergent possible futures for the network but remain confused on how best to respond and need a clear narrative around how we see the future will unfold.
- Stakeholders believe we must minimise discretionary expenditure if we are intending to seek accelerated depreciation of the network.
- Stakeholders interpret a 'least regrets' action as being an action that would be taken regardless of what future for our network eventuates, and that discussions need to take potential future regrets into account.
- While acknowledging there are regulatory obligations, many stakeholders feel that continuing to connect new customers and delivering high levels of safety and reliability conflict with our proposal for accelerated depreciation, which they believe is inconsistent with how a network with an uncertain future should be investing.
- Most stakeholders want spending on hydrogen readiness to be minimised in this access arrangement period, given the widespread pessimism around the viability of a Hydrogen Hero pathway. Given this, many are also uncomfortable with paying for hydrogen research, though some, as a matter of principle, feel they should not pay for innovation under any circumstances, even if there is a known long-term future for the network that involves a material role for hydrogen.
- We need to think about how we may be able to protect customers on our networks for whom it is difficult to transition away from gas if/as needed.
- Stakeholders generally understand that we must be given a reasonable opportunity to recover our costs (under the regulatory compact) but question what share of the risk should be worn by each of customers, government and our business. They are interested in the timing of any cost-recovery from customers i.e., how much accelerated depreciation we should be permitted to pursue, and how that is spread across future access arrangement periods. Most stakeholders are open to discussing these questions, though some consider we should assume the entirety of the asset stranding risk and they do not support accelerated depreciation under any circumstances.
- Stakeholders generally understand and acknowledge the value in keeping our options open i.e., not closing our network off to the possibility of carrying hydrogen in the future, or not shutting it down before it reaches end of life on the assumption of an electrification pathway. However, some felt quite strongly that we need to select one of the four scenarios considered by the Expert Panel as representing the future of our and commit fully to preparing for that. There is broad sentiment though, that the scenarios developed by the Expert Panel are not equally likely, and that we should put more effort into preparing for those that are more likely (widespread electrification of gas) than those that are not (an optimistic future for hydrogen in residential and commercial settings).
- Customers and stakeholders are interested in the long-term price path for energy (gas included). They see value in maintaining affordability and price stability, and many consider this to be of critical importance. The usefulness of accelerated depreciation as a tool to help control long-term prices appears to be understood, though we were asked to look further into the time value of money i.e., smoother long-term prices versus price cuts now,

and consider sharing any net present value (NPV) benefits of earlier and greater accelerated depreciation with customers.

- A concern was raised that accelerated depreciation of the sunk investment might lead to a point where the building block model doesn't generate enough cashflow for us to continue operating.
- We received broad feedback that the demand forecasts we have used may be too optimistic, particularly in light of the recently-released 2022 GSOO step change scenario, speculation around the policies that might be included in the Roadmap, and anecdotal evidence around rising anti-gas sentiment among gas customers and the community more broadly.

Based on the feedback that we received on our draft proposal, we have responded in this submission in a material manner. We have:

- Reduced capex, particularly by removing expenditure on ensuring hydrogen readiness in our network. This can be progressed at the later part of this decade if the need becomes more certain.
- Cut opex, particularly removing step changes and the Gas Network Innovation Scheme.

However, we have increased the amount of accelerated depreciation (from $130 million to $150 million) that we are seeking in this proposal. This reflects our view that there is a higher risk to our gas network relative to when we released our draft proposal. This is informed by the preliminary modelling released by the Victorian Government and many statements from stakeholders sceptical of the future of the gas networks. In increasing our accelerated depreciation proposal, we have remained mindful of the short-term price impacts on our customers and consider that we have appropriately balanced this against longer term price impacts and the stranding risks we face.

3.6. Expert Panel

In collaboration with our fellow Victorian networks, Australian Gas Networks (AGN) and Multinet Gas Networks (MGN), we convened a panel of nine independent industry experts to design potential future scenarios that Victorian gas networks could consider and plan for. Each member brought unique experience and skills to the Panel, ensuring that all facets of the electricity and gas industries were captured in each scenario. [31]

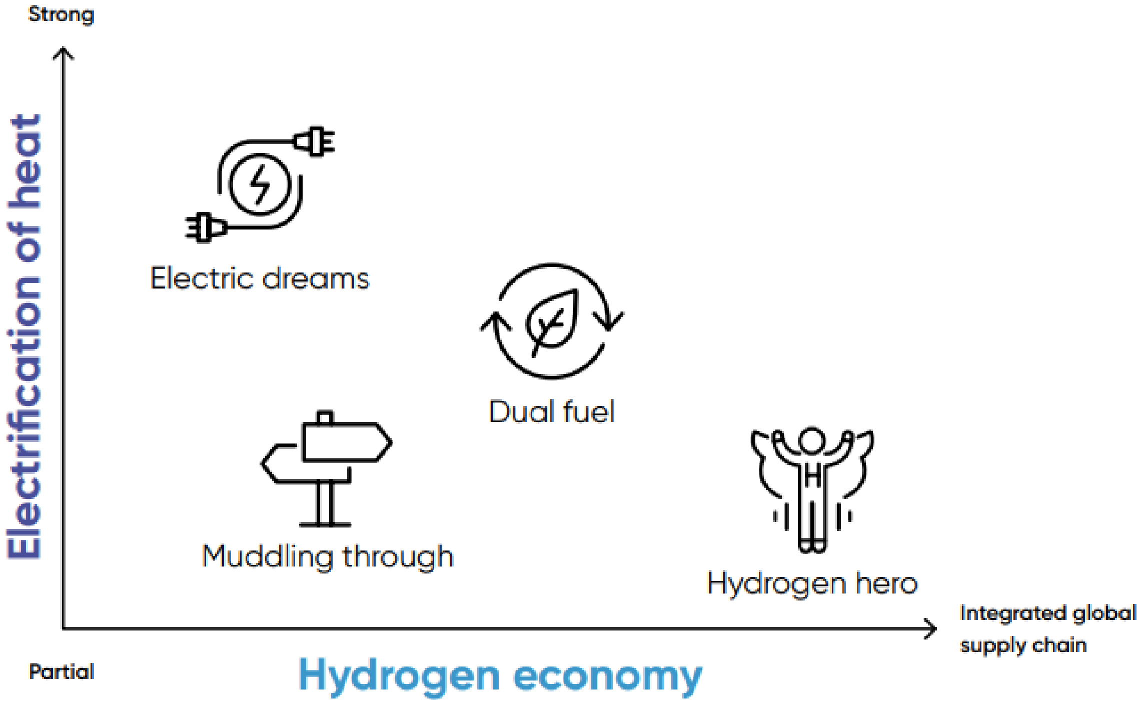
The aim of the Expert Panel was to consider the range of possible outcomes for the future of gas networks. We used an independent consultant, KPMG, to guide the Expert Panel through the future of gas scenario development phase. [32]

For each scenario, the three gas network businesses developed hypothetical plans and decisions that could deliver the required outcomes for customers, investors and stakeholders under that scenario. Discussions with the Expert Panel continued throughout the development of these plans (and members made themselves available for stakeholders to ask them questions on their analysis and how networks had taken that analysis into account when developing their plans).

Over the course of four workshops, the Expert Panel defined four plausible scenarios (see figure below). These four scenarios are based on different levels of electrification and adoption of renewable gasses, and different factors driving these scenarios.

[31] Information on the composition of the Expert Panel was detailed in our draft proposal, which is available through the gas matters website: https://gasmatters.agig.com.au/victorian-engagement-plan (accessed 27/05/2022).
[32] KPMG, Future of gas, What are the plausible scenarios for Victoria's 2030-2050 energy system and what role does gas play in each?, Development of future scenarios, co-design summary report, October 2021 – see Appendix 2.

Figure 3.1: Expert Panel scenarios



Source: KPMG, Future of gas, What are the plausible scenarios for Victoria's 2030-2050 energy system and what role does gas play in each?, Development of future scenarios, co-design summary report, October 2021

Each scenario envisaged different degrees of transition to a renewable gas (hydrogen) network, or the electrification of the load. The Expert Panel then explored the potential future impact of those scenarios on the gas distribution network. A brief description of each scenario is outlined below:

- **Electric Dreams:** This scenario is characterised by widespread electrification of the gas load underpinned by strong market driven growth of electricity renewables, investment in system flexibility and efficiency, and policy support for net zero by 2050. Accelerated electrification of a wide range of applications leads to a rapid rise in electricity demand, which outstrips renewable supply and briefly prolongs the reliance on fossil fuel generation. This is largely replaced with renewables and grid firming infrastructure at an orderly and increasing pace over the next decade. Gas distribution networks become increasingly stranded as consumers electrify through the late 2030s.
- **Dual Fuel:** This scenario is characterised by the fusion of extensive domestic electrification and the development of a material export industry for hydrogen in the medium term. Domestic hydrogen is utilised for certain industrial applications and in select residential locations. Net zero is achieved by 2050 due to focused market and policy action, and the orderly retirement of fossil fuel use. Gas distribution networks are largely stranded by 2050, however a subset services 100% hydrogen customers.
- **Muddling Through:** This scenario reflects an uncontrolled, uncoordinated future characterised by stop-start progress toward net zero and limited change to energy market dynamics. In this scenario net zero by 2050 is at risk, driven by disorderly and uncoordinated industry and Government policy action. This leads to a combination of electrification and the use of renewable gases, with some gas distribution networks converted to low carbon fuels in the late 2030s as they attempt to remain viable.
- **Hydrogen Hero:** This scenario involves Australia reaching net zero by 2050 through the orderly growth of a significant hydrogen industry for export and domestic use, enabled by widespread renewable gas generation. Hydrogen and electricity markets become linked in the 2030s to provide stable, economically competitive, decarbonised energy. Gas distribution networks are fully utilised to deliver hydrogen for home, commercial and industrial applications.

Further information on the process undertaken is provided in the Expert Panel's report.[33]

[33] KPMG, Future of gas, What are the plausible scenarios for Victoria's 2030-2050 energy system and what role does gas play in each?, Development of future scenarios, co-design summary report, October 2021.

3.7. How we developed our proposal

As explained above, the gas distributors developed hypothetical plans in response to each of the scenarios developed by the Expert Panel. The price and service outcomes from these plans were determined by applying models developed by AusNet, AGIG and ACIL Allen. These models form part of this submission and are now publicly available.[34] In the remainder of this section, we briefly outline what we modelled, the key inputs we used, as well as the key results from our modelling. We have also attached a detailed technical appendix with additional information on the assumptions and the results of our modelling.[35]

3.7.1. What we modelled

We developed two, interconnected, models to help us examine the scenarios produced by the Expert Panel:

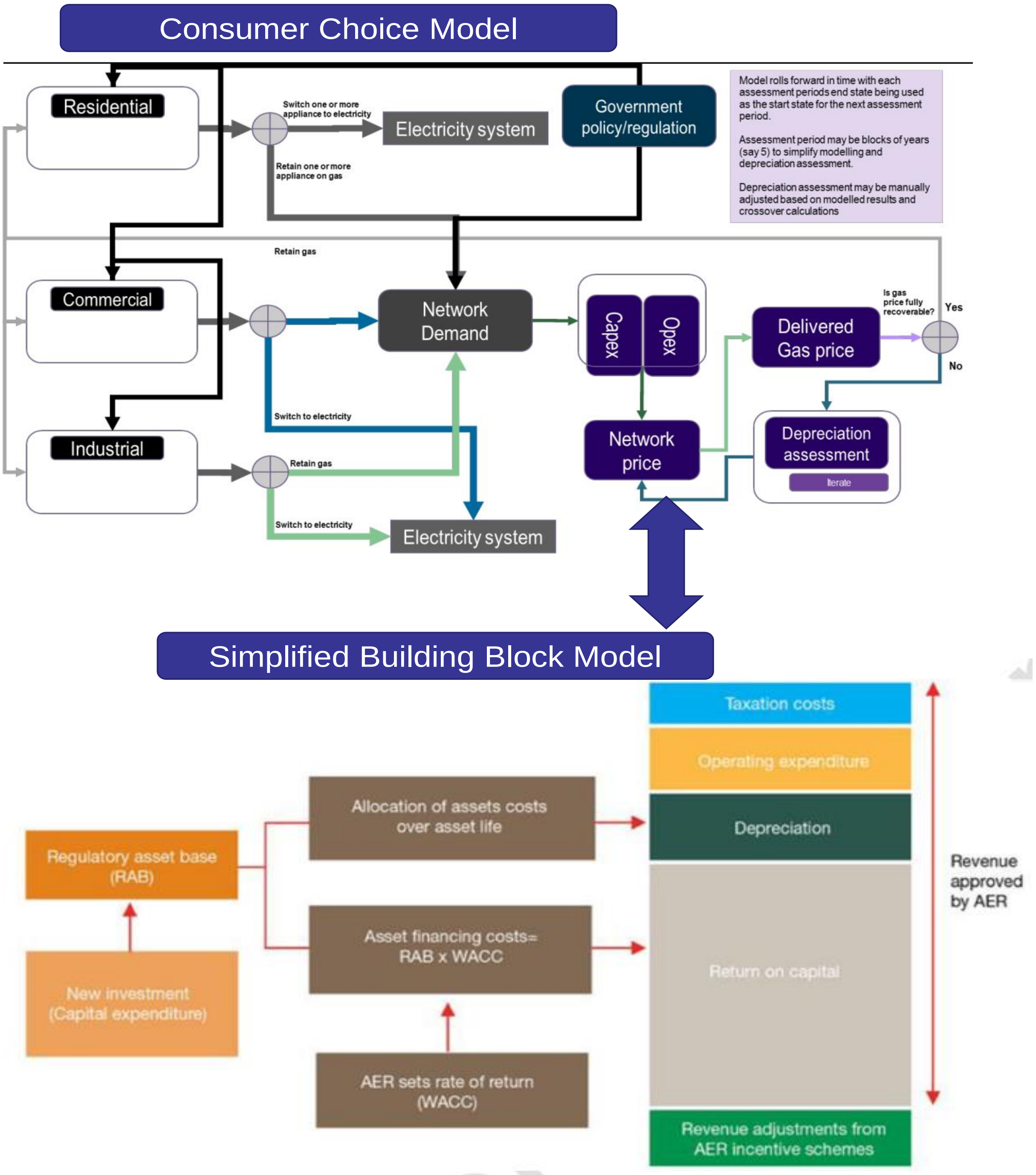
(1) A consumer choice model that examines the decisions that gas consumers may take based on the relative cost of purchasing and operating electric or gas appliances. For example, it considers at what point/price a customer will decide to switch from gas to electricity. ACIL Allen prepared this model and provided some of the key inputs into this model.

(2) A simplified building blocks model that calculates the network costs under the different assumptions and feeds those costs into the consumer choice model, meaning that the results of the consumer choice model is sensitive to changes in network costs. AusNet and AGIG developed these building blocks models and linked them to the consumer choice model.

By developing these two models we were able to run simulations about future developments in the gas and electricity sectors and determine possible customer responses. This allowed us to model the four scenarios provided by the Expert Panel and the sensitivities around these scenarios, and to understand how the key drivers changed outcomes in each model. In particular, this allows us to model the impact of different accelerated depreciation amounts under each scenario. The way each model operates is represented diagrammatically in the figure below.

[34] ACIL Allen, Future of Gas – Model Description.
[35] AusNet – Technical appendix - Modelling results and further explanation.

Figure 3.2: High level schematic of our modelling



Source: AusNet and Acil Allen

The consumer choice model calculates the relative costs, by using a NPV of a switching decision from gas to electricity. As the cost of gas increases compared to electricity, more customers decide to switch away from gas. This creates a key feedback loop, in that as gas prices rise, more customers may choose to use electricity, which places upwards pressure on the prices for remaining customers. If gas prices rise sufficiently high, then a 'death spiral' can occur where all gas customers seek to leave the network over a short period of time. A death spiral would create an outcome where we would be unable to recover all of our allowed revenue from our customers unless prices are set higher than customers can bear (which would simply drive customers of our network faster and still leave us unable to recover our costs. Such an outcome may necessitate and/or precipitate government intervention or assistance.

Key inputs into this switching decision are:

- **Wholesale prices of gas, electricity and hydrogen**. We have sourced third party forecasts of these inputs for each of the scenarios. Feeding into these price forecasts is an understanding of the economic and demand environment that would exist for these inputs in these scenarios. For example, under the Electric Dreams scenario, there would be widespread adoption of renewable electricity generation, putting downward pressure on electricity prices. This makes the consumer decision to switch to electricity more attractive.

- **Appliance costs.** Upfront costs of purchasing appliances is a material portion of the NPV calculation and can have a significant impact on the switching decision. We have used internal benchmarking to set the appliance costs in the models.
- **Consumer preference.** We use 'S-curves' to set the sensitivity of customers to changes in the NPV.[36] We have used 3 S-curves, reflecting that consumer preferences are likely to be a key driver of the scenario outcomes. For example, under the Hydrogen Hero scenario, consumers are less sensitive to changes in the cost, reflecting that they choose gas for non-financial reasons (e.g., they prefer using it). Conversely, under the Electric Dreams scenario, consumers are more sensitive to price changes, suggesting that they start valuing the environmental benefits of electrification more highly.
- **Policy inputs.** The model allows us to overlay policies that impact consumer choices. Key policies that we can model are the introduction of subsidies on appliance switching away from gas, or a connections moratorium.

Table 3.1: Key inputs

Scenario Driver	Electric Dreams	Dual Fuel	Muddling Through	Hydrogen Hero	Data Source
Wholesale domestic electricity price	L	L-M	M	L	ACIL - Powermark (adjusted)
Wholesale domestic natural gas price	H	H	M	H	AEMO Input methodologies
Wholesale domestic hydrogen price	M	L-M	H	L	Hydrogen Council and CEFC
Electricity network demand	H	H	M	H	Implied in price
Natural gas demand	L	L	H	L	Implied in price
Hydrogen export demand	L	H	L	H	Implied in price
Hydrogen industrial demand	L	M	L	H	Implied in price
Hydrogen residential & commercial demand	L	L-M	L	H	Implied in price
Delivered electricity price	M/H	M	H	M	ACIL - Powermark (adjusted)
Extent of decarbonisation policy	H	H	L	H	Scenario dependent
Pace of decarbonisation to 2030	M	M	M	M	As per relevant models
Blending H2 uptake	L	M	L	H	10% by 2030, 100% in 2040 for HH
Extent of grid scale battery storage	H	H	L-M	H	Implied in price
Extent of renewable electricity supply	M	M-H	L-M	H	Implied in price
Extent of other dispatchable energy supply	H	H	M	M	Implied in price
East coast domestic natural gas production	L	L	H	L	Implied in price

[36] ACIL Allen, Future of Gas – Model Description.

Transmission connected hydrogen	L	M-H	L-M	M-H	Not directly used but implied in price
Distribution connected hydrogen	L	L-M	L-M	H	Not directly used but implied in price

Source: AusNet

3.7.2. Modelling results

We have modelled the four scenarios provided by the Expert Panel and the outcome of modelling is summarised below. Prior to exploring this modelling in detail, we note:

- The scenarios we have modelled show divergent paths for the gas network, and even within each scenario, there is scope for considerable divergence (due to input sensitivities).
- The scenarios we have modelled serve as useful guides to the possible future, rather than an explicit prediction.
- We have not chosen a 'winning' scenario. At this stage, there is too much uncertainty and deciding on the one scenario that is the most likely to emerge is not prudent.

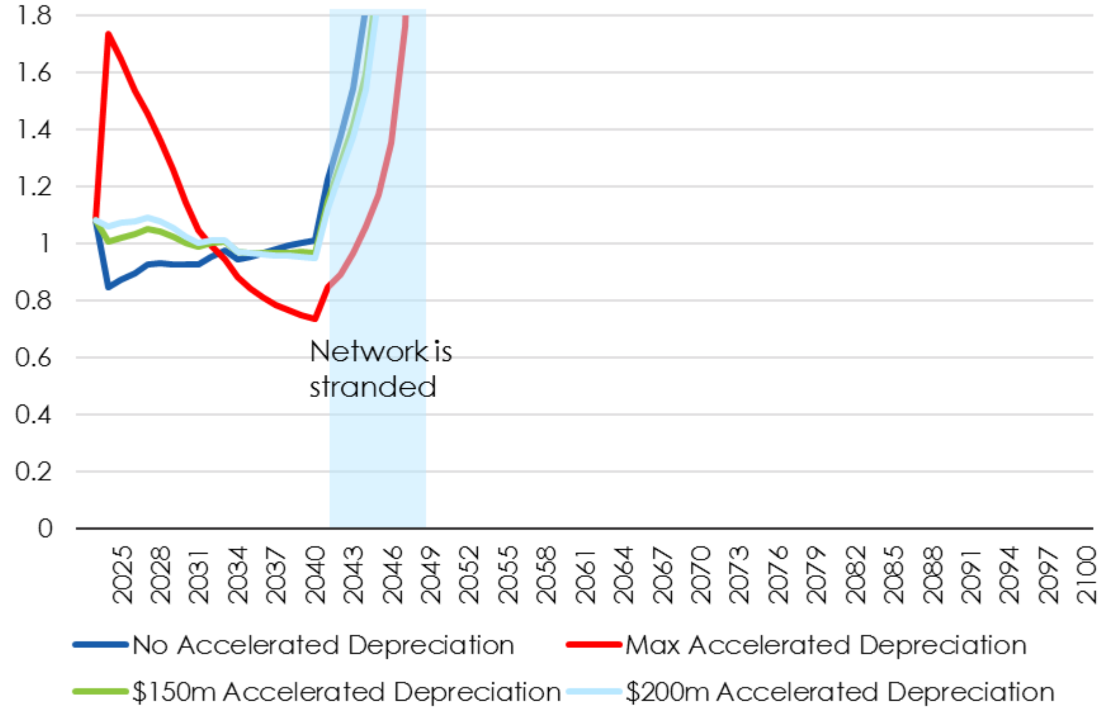
On the third point, some stakeholders have suggested that one outcome may be more likely than another and that we should choose a winning scenario or weight the scenarios together into an average outcome. While we acknowledge these concerns, there is still insufficient certainty to enable us to 'pick a winner'. For the same reason, we do not consider that selecting an 'average' approach would deliver a prudent or efficient outcome. Given the difficulty of forecasting the future with any certainty, we have proposed a prudent and efficient proposal that reflects the current levels of uncertainty facing the industry, while also actively seeking to minimise potential costs to our customers.

3.7.3. Scenario 1: Electric Dreams

Under this scenario, we have assumed there is a strong policy push towards electrification, which sees gas customers increasingly leaving the network, and our gas network largely decommissioned by 2050.

Gas customers that remained on the gas network would experience increasing prices as fewer customers remain to meet the sunk costs of our investment in the network to ensure the delivery of safe and reliable gas. While slowing the rate of transition of customers from the gas network to the electricity network could help mitigate price rises, in most modelled scenarios, prices accelerate quickly and become unacceptable/unrecoverable for remaining gas customers (without Government support). This is illustrated in Figure 3.3 below, where we see the residential network cost of gas rise very quickly from 2040. In this scenario, it is assumed that parts of the network are shut down from 2040 onwards, which quickly increases prices for the remaining.

Figure 3.3: Residential distribution (volumetric) price per GJ Growth Index



Source: Electric Dreams – Consumer Choice Model and Electric Dreams – Building Blocks Model

Figure 3.3 shows the price path that would eventuate from four possible accelerated depreciation profiles. The dark blue line shows the price path (specifically, the variable component of the residential bill) with no accelerated depreciation.[37] The green line shows the price path in this scenario with $150 million accelerated depreciation (our proposal), the light blue line shows $200m accelerated depreciation and the red line shows a theoretical 'maximum' level of accelerated depreciation. In our modelling ~$700 million of accelerated depreciation in the next access arrangement period is the upper limit on accelerated depreciation. If more than this maximum amount of accelerated depreciation is used, then the price rises faced by customers in the short term is too high and starts the death spiral effect, essentially forcing us to adopt an electrification pathway.

While accelerated depreciation can partly help mitigate future price rises, our modelling shows that in an Electric Dreams scenario this is insufficient to prevent increasingly unpalatable price rises. Under this scenario we would, therefore, face increased asset stranding risk, as we would be unable to fully recover our capital base from our customers as they would be increasingly leaving the gas network following the significant price rises. From the point customers cannot cover the costs of the network, there may need to be some government assistance to keep the gas network operating until an orderly decommissioning of the network can be completed.

Under this scenario, the capital base will start to decline (due to a reduction in capex and no new connections) and customer numbers and consumption would begin to decline. However, a rapid shutdown of the network would still occur in 2040, the time at which prices become unsustainable (which in the model manifests as an abrupt end to the network in 2045. Some of the price and asset stranding risk could be mitigated by slowing the transition off the gas network, but this will be dependent on Government policy and consumer choices.

3.7.4. Scenario 2: Dual fuel

Under this scenario, we have assumed there is considerable electrification of the gas load and many segments of the gas network are decommissioned. However, some areas of the gas networks are repurposed to provide hydrogen to our residential and commercial customers. This means that, relative to the current situation, the gas networks capture a much smaller share of the energy consumption but remains a viable part of the energy mix.

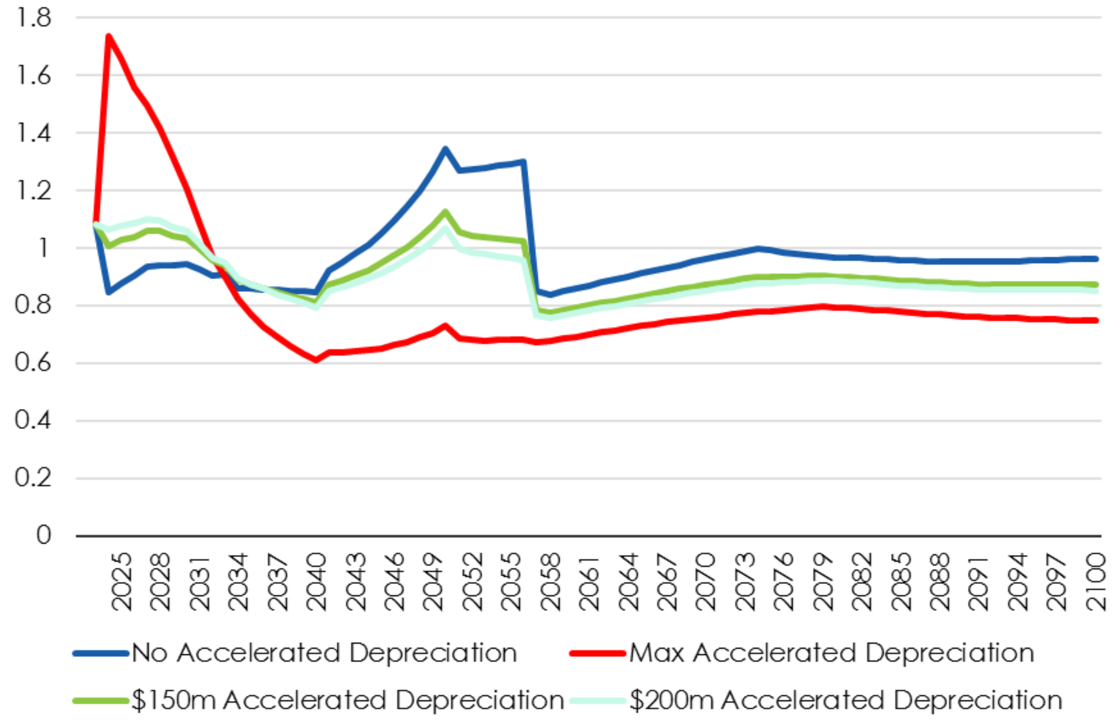
We have used simple assumptions to identify the areas of our network that are more likely to be able to be repurposed for hydrogen and modelled shutting down the other parts of the network from 2040.

To ensure future gas prices are not too high in the future (which will drive customers away from using the repurposed hydrogen network), accelerated depreciation is critical. Accelerated depreciation provides protection against future high prices by allowing sunk costs to be recovered earlier than would otherwise be case. Where accelerated depreciation is not implemented and the future price of gas is too high, the Dual Fuel scenario could inadvertently tip into the Electric Dreams scenario (see above).

The figure below shows the price path that would eventuate from four possible accelerated depreciation profiles used in the Dual Fuel scenario. The dark blue line shows the price path (specifically, the variable component of the residential bill) with no accelerated depreciation.[38] The green line shows the price path in this scenario with $150 million accelerated depreciation (our proposal), the light blue line shows $200m accelerated depreciation and the red line shows a maximum level of accelerated depreciation. If more than this maximum amount of accelerated depreciation is used, the price rise in the short term is too high and the death spiral effect is initiated, forcing an electrification pathway on the business.

[37] The price paths for the fixed component and commercial customers can be found in the modelling files. As they are similar in outcome they are not presented here.
[38] The price paths for the fixed component and commercial customers can be found in the modelling files. As they are similar in outcome they are not presented here.

Figure 3.4: Residential distribution (volumetric) price per GJ Growth Index



Source: Dual Fuel – Consumer Choice Model and Dual Fuel – Building Blocks Model

In this scenario, accelerated depreciation significantly mitigates future price impacts on customers.

3.7.5. Scenario 3: Muddling Through

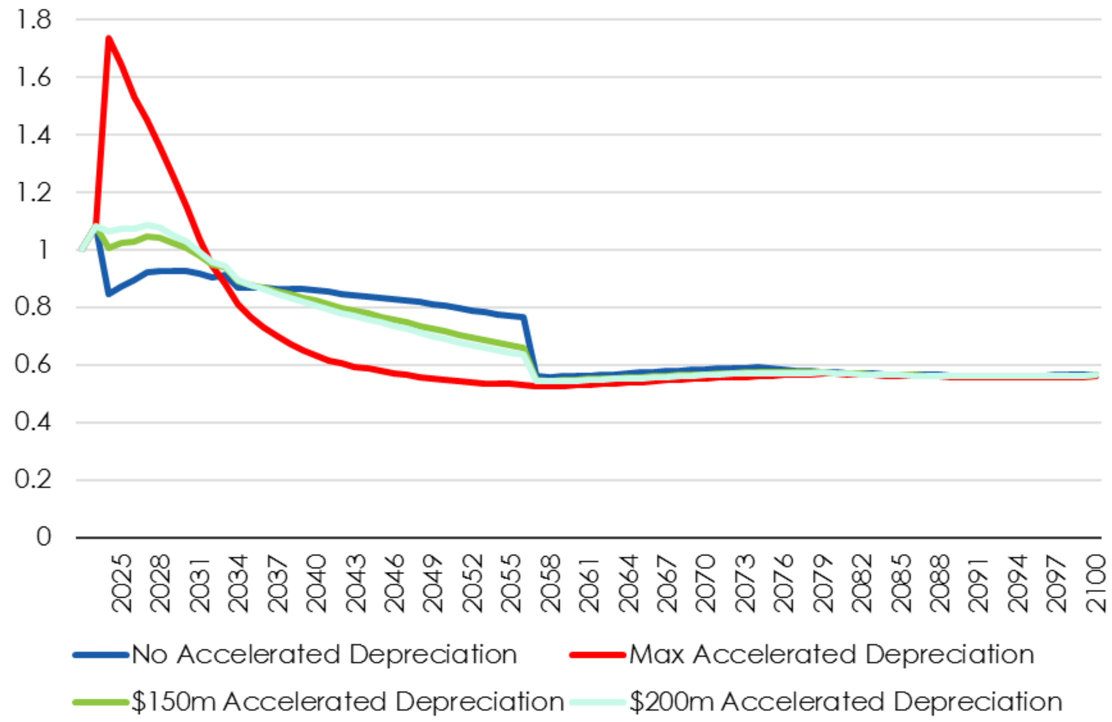
The Muddling Through scenario assumes no clear policy direction regarding the future of gas in the short term. The delivery of natural gas, therefore, continues to be the dominate fuel source until it becomes untenable. In the longer term, either an electrification or hydrogen future is likely to emerge.

Accelerated depreciation can (again) help mitigate future price increases for gas customers, but there is little certainty about where prices will eventually settle.

The figure below shows the price path that would eventuate from four possible accelerated depreciation profiles. The dark blue line shows the price path (specifically, the variable component of the residential bill) with no accelerated depreciation.[39] The green line shows the price path in this scenario with $150 million accelerated depreciation (our proposal) the light blue line shows $200m accelerated depreciation and the red line shows a maximum level of accelerated depreciation. If more than this maximum amount of accelerated depreciation is used, the price rise in the short term is too high and this scenario also initiates the death spiral, thus forcing an electrification pathway on the business.

[39] The price paths for the fixed component and commercial customers can be found in the modelling files. As they are similar in outcome they are not presented here.

Figure 3.5: Residential distribution (volumetric) price per GJ Growth Index



Source: Muddling Through – Consumer Choice Model and Muddling Through – Building Blocks Model

3.7.6. Scenario 4: Hydrogen Hero

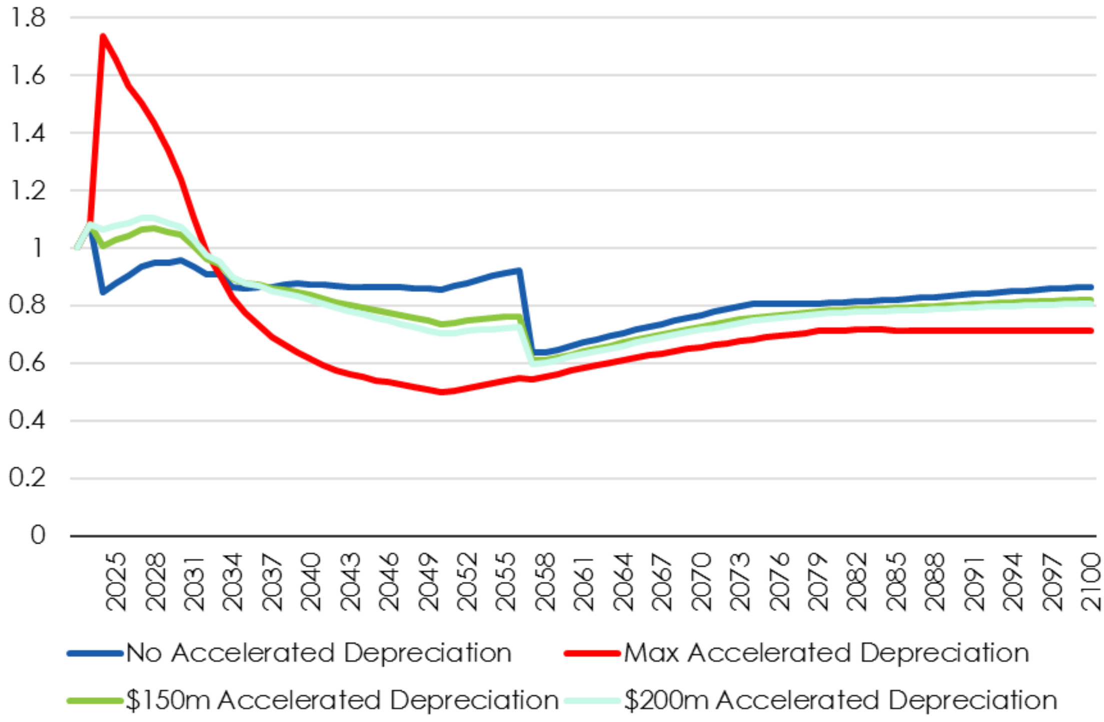
Under this scenario, the gas networks can significantly repurpose to a hydrogen future. Population growth drives further uptake and the gas networks remain viable in the long term.

Accelerated depreciation is not necessary as the customer base continues to grow, although it does help keep hydrogen prices lower in the future. Our proposed accelerated depreciation does not drive negative consequences for the network as its impact on the prices is not sufficient to drive switching decisions in the short term, and it leads to lower prices in the future.

The figure below again shows the price path that would eventuate from four possible accelerated depreciation profiles. The dark blue line shows the price path (specifically, the variable component of the residential bill) with no accelerated depreciation.[40] The green line shows the price path in this scenario with $150 million accelerated depreciation (our proposal) the light blue line shows $200m accelerated depreciation and the red line shows a maximum level of accelerated depreciation. If more than this maximum amount of accelerated depreciation is used, the price rise in the short term is too high and again initiates the death spiral, once more forcing an electrification pathway on the business.

[40] The price paths for the fixed component and commercial customers can be found in the modelling files. As they are similar in outcome they are not presented here.

Figure 3.6: Residential distribution (volumetric) price per GJ Growth Index



Source: Hydrogen Hero– Consumer Choice Model and Hydrogen Hero– Building Blocks Model

3.7.7. Key conclusions to draw from the models

The analysis we have undertaken demonstrates that accelerated depreciation is the appropriate way to manage the uncertain future of the gas networks in the next access arrangement period. In the face of uncertainty, accelerated depreciation allows us to alter the balance of short- and long-term price impacts on our customers as well as the risk of capital under recovery faced by our investors. Our analysis demonstrates that there is a wide range of accelerated depreciation proposals that could be justified and that ultimately a judgement is needed to select from within this range. For example, if we were certain that an electrification scenario was to emerge, we would likely seek a higher amount of accelerated depreciation (possibly as high as $700 million) to help minimise the future price impacts and minimise our recovery risk. Conversely, if we were certain of a hydrogen hero scenario, we would see less (or no accelerated depreciation) required. In choosing a proposal within this range we have tested the impacts our proposal on our current and future customers and our investment risk.

Accelerated depreciation increases prices in the short term but lowers future prices. So for our customers we have considered the balance between current and future prices and have ensured that the price path we are proposing can be borne by customers in the next access arrangement period and are not experiencing material price increases in the short term. While we accept that many of our customers would prefer to see lower prices in the short term, our customer engagement indicated a willingness among some customers to consider the longer-term implications and the trade-off between higher prices in the short terms and lower prices in the long term. Nonetheless, there is far from unanimity between customers in this respect. We are also very cognisant that many customers and stakeholders do not support our accelerated depreciation proposal because the want or need lower prices now, particularly with rising gas wholesale gas prices, or that they do not think stranding risk should be borne by customers. We have listened to and understood their views and explained why our position is, nonetheless, reasonable in seeking to balance the interests of all our customers and investors in both the short and long term.

For our business, we have tested whether our proposal allows for optionality and gives our business the best opportunity to either transition to a hydrogen network in the future or recover our sunk investment if an electrification scenario emerges. Flowing from the four scenarios provided by the Expert Panel, our analysis has been assessed against three possible 'future states', being:

- Hydrogen transition is viable.
- Electrification is the only viable option.
- The viability of hydrogen is on a knife edge.

It is not clear which state will play out and so it is prudent to seek to make a decision that is optimal under all possible states.

If the Hydrogen transition is clearly viable, then our proposal is not detrimental to this outcome. Importantly, our proposed accelerated depreciation is not high enough to trigger a death spiral, and does not leave us uncompetitive in the short term. While prices in the short term may be higher than strictly necessary, customers will receive lower prices in the future. In any event, we have sought to seek a reasonably stable price path and so consider prices in the next access arrangement period should be acceptable. Finally, any accelerated deprecation decision is completely reversable at future access arrangements if the prospects for the network change.

Alternatively, if electrification is the only viable option, then our proposal reduces the stranding risk faced by our business and helps mitigate future price impacts on customers from us recovering our sunk investment. The level of accelerated depreciation proposed does not fully mitigate these risks, but is a prudent start to addressing these issues. It also provides some protection for vulnerable domestic and business customers that will find it hard to transition away from the gas system.

If the hydrogen future is sitting on a knife edge, then a choice to accelerate depreciation now may ensure that this hydrogen future remains viable (because it delivers lower future prices). Failure to accelerate depreciation now may prevent a hydrogen future from developing (because we lose the opportunity to lower future prices) and it will be too late to use accelerated depreciation in this manner in the next access arrangement period. We, therefore, see the use of accelerated depreciation as a means to help preserve the viability of a hydrogen future, which is a key and fundamental benefit to the long-term interests of consumers, current and future, and of our access arrangement proposal.

However the future of the gas networks evolves, our proposal is vitally important in allowing that future to evolve, or at worst has no materially detrimental impacts. As such, it is a prudent and efficient approach to dealing with the uncertain future of the gas networks and clearly aligns with the NGO to advance the long-term interests of customers.

3.8. Addressing stakeholder feedback

In this section we address three questions raised by the CCP in response to our draft proposal, which they considered we needed to address: [41]

- How future expenditure will be treated for regulatory purposes (by us and by the AER).
- Safeguards to prevent networks repatriating the additional cashflow to equity holders and creating a potential cashflow shortfall in future, thus requiring consumers to 'pay twice' for the same benefit.
- Whether we considered the potential risk of asset stranding when making past investments (that is, did we ensure we prudently consider this risk in the past).

The CCP also asked about the legal basis for the AER to approve our accelerated depreciation which we have addressed in Chapter 9.

3.8.1. How future expenditure will be treated for regulatory purposes?

We have proposed to shorten asset lives for many long-lived assets from 60 years to 50 years. This reflects an engineering analysis that 50 years better reflects the actual useful life of these assets.

As previously discussed, there is also the possibility that the gas networks will be able to successfully transition to viable hydrogen networks. In this circumstance, the risk of asset stranding risk becomes lower in the future and fundamental changes to the regulatory framework will not be necessary.

However, there is a risk that the network will need to be wound down at some point. If this is to occur it will require concerted government action including changes to the regulatory framework to facilitate this occurring in an orderly and cost-effective manner (analogous to the shutdown of analogue television). However, as this eventuality is not certain, it is too early to propose specific actions to be taken in the forthcoming access arrangement period. As such, we are not proposing a further shortening of the asset live or proposing broader changes to the regulatory treatment of expenditure at this time.

[41] CCP28, Advice to the AER, 31 March 2022.

3.8.2. Are there any safeguards to prevent networks repatriating the additional cashflow to equity holders creating a potential cashflow shortfall (solvency?) problem in future requiring consumers to 'pay twice' for the same benefit?

As a regulated business, we do not have the option to withdraw our services from the market and we are required to operate our network in accordance with our licence and the larger regulatory framework, including the NGL and NGR, the Gas Distribution System Code of Practice, the Energy Retail Code of Practice and all other codes, standards, rules and guideline, which are specified by the Essential Services Commission to apply to us. [42]

Therefore, even if we are faced with a cash shortfall, this does not remove our obligation to comply with the regulatory framework. In the unlikely event we were faced with a cash shortfall, we would seek additional equity funding from the marketplace. Given the situation envisaged, this would likely occur at a significant discount to prior valuations and represent a loss to our existing equity holders. However, while this is a situation best avoided it has no impact on our customers.

3.8.3. Did we consider the risk of asset stranding when making past investments?

Most of our capex is spent on connecting customers and safety and reliability programs. We do not consider that even faced with material asset stranding risk, that we can materially lower our capital expenditure program for the following reasons:

(1) We must connect the gas installation of a customer that resides within the minor or infill extension area on fair and reasonable terms and conditions. This means anyone within 1km radially of our existing network must be offered a connection. We have had record numbers of connections over the past four years, showing continued strong demand for connections to our gas network. Connections and related augmentation expenditure is a key driver of our proposed capex program (making up approximately 40% of net capex).

(2) The majority of the remainder of our capital expenditure (nearly 50% of the remainder) is the mains replacement program, which is a safety driven program. Regardless of the asset stranding risk, we are obliged to manage our network in a safe and effective manner. We agree that if the network approaches a wind down state, a transition to opex solutions may become optimal, but this is not the case currently. It would not, therefore, be prudent or efficient to adopt such an approach at this time. Unfortunately, asset stranding risk doesn't materially change our expenditure at this time as most of our expenditure is focused on connecting customers or reliability and safety programs.

(3) Until recently, there was less doubt about the future of the gas networks. As recently as 2014, the Victorian Government was actively pursuing an expansion of gas networks to regional towns. For example, we were provided subsidies under the Government's Energy for the Regions Program to connect Avoca, Bannockburn and Winchelsea to our reticulated gas network. This underscores the relatively recent nature of the changes in the long term prospects for our network.

(4) Even under accelerated electrification scenarios, a significant proportion of customers will require a safe and reliable gas distribution service up until 2050 and likely beyond.

The introduction of the capital expenditure incentive scheme (CESS) in the 2018-23 access arrangement period was an important additional incentive we proposed be included to ensure our capex is efficient. Furthermore, as demonstrated in Chapter 7, we have long been one of the most efficient gas networks in Australia.

3.9. Supporting documents

- ASG – GAAR – Appendix 1 – KPMG, Future of gas, What are the plausible scenarios for Victoria's 2030-2050 energy system and what role does gas play in each?, Development of future scenarios, co-design summary report, October 2021– PUBLIC
- ASG – GAAR – Appendix 2 – ACIL report – 1 July 2022 – PUBLIC

[42] AusNet Gas Services Pty Ltd Distribution Licence, clause 4(a).

- Future of Gas Models:
  - ASG – GAAR – Appendix 16 – Electric Dreams – Consumer Choice Model – 1 July 2022 – PUBLIC
  - ASG – GAAR – Appendix 17 – Electric Dreams – Building Blocks Model – 1 July 2022 – PUBLIC
  - ASG – GAAR – Appendix 18 – Dual Fuel – Consumer Choice Model – 1 July 2022 – PUBLIC
  - ASG – GAAR – Appendix 19 – Dual Fuel – Building Blocks Model – 1 July 2022 – PUBLIC
  - ASG – GAAR – Appendix 20 – Muddling Through – Consumer Choice Model – 1 July 2022 – PUBLIC
  - ASG – GAAR – Appendix 21 – Muddling Through – Building Blocks Model – 1 July 2022 – PUBLIC
  - ASG – GAAR – Appendix 22 – Hydrogen Hero – Consumer Choice Model – 1 July 2022 – PUBLIC
  - ASG – GAAR – Appendix 23 – Hydrogen Hero – Building Blocks Model – 1 July 2022 – PUBLIC

4. Demand and customer forecasts

4.1. Key points

- Our customer base is forecast to grow by 2.1% per annum over the next access arrangement period. While this is below the current access arrangement period (2.7%), it is driven by independent housing start projections by the Victorian Government and supported by the Housing Industry Association's (HIA's) own forecasts.
- Average residential consumption is forecast to fall by 1.3% per annum over 2024-28. This continues the general downwards trend in consumption per customer which has been seen over the past decade.
- This declining gas usage per customer is driven by a range of factors, including energy efficiency, house size, customers switching appliances from gas to electricity and warmer winters.
- The growth in the customer base slightly offsets the decline in consumption per customer, resulting in a small increase in the total volume of gas delivered through the network over the access arrangement period.
- Demand from industrial customers (measured by maximum hourly quantity) is forecast to fall by around 1% per annum over the next access arrangement period.
- Demand and customer forecasts assume no change to existing government policies relating to the delivery of gas to end users. Post the release the Victorian Government's Roadmap we may, however, need to consider if changes to these forecasts are required.

4.2. Chapter structure

The remainder of this chapter is structured as follows:

- Section 4.3 outlines our customer number forecasts.
- Section 4.4 summarises our energy consumption forecasts for residential and small commercial customers.
- Section 4.5 presents our maximum demand forecasts for industrial customers.
- Section 4.6 discusses some of the broader issues in forecasting gas demand in an environment of policy uncertainty.
- Section 4.7 provides details of where additional information on issues raised in this chapter can be found.

4.3. Customer number forecasts

We developed an independent view of demand forecasts in our network for the forthcoming access arrangement period by engaging The Centre for International Economics (CIE).[43] CIE also prepared our customer and demand forecasts for both the 2008-2012 and 2013-2017 access arrangement periods, both of which were largely accepted by the AER.

[43] The Centre for International Economics (CIE), 2021, *2023 – 2028 GAAR Demand, Energy and Customer Forecast*.

4.3.1 Residential customer forecast methodology

4.3.1.1. Determining 'potential' customers

CIE bases its customer forecasts on publicly available, independent data on projections of dwellings growth. For the forthcoming access arrangement period, CIE selected the Victorian Government's official projection of population and households, Victoria in Future 2019 (VIF2019).

VIF2019 contains projections of 'occupied private dwellings' at the Local Government Area (LGA) level. These occupied dwellings forecasts are the basis of the customer forecasts, being the number of houses that could potentially connect to gas networks (where available).

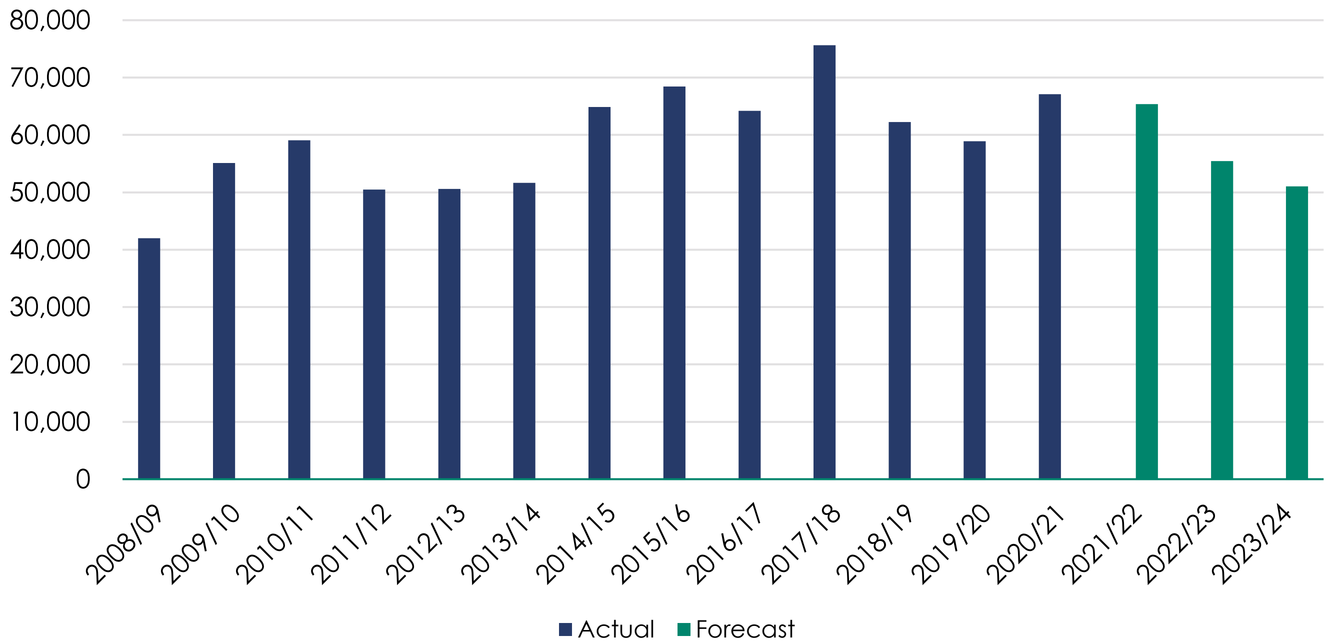
Using LGA-postcode concordance tables, CIE then maps these occupied dwellings forecasts down to the postcode level. This level of granularity has several benefits, including:

- The forecasts can be easily translated into pricing zones, which are largely segregated by postcode.
- There is a large amount of publicly available data at the postcode level, or at the LGA level, which can be applied to the postcodes within each LGA.
- Forecasts of customer growth and demand at the postcode level allow us to prepare network strategies and asset management plans with more confidence.

The VIF2019 projections assume a reduction in the rate of future growth in occupied dwellings relative to the recent historic growth. AusNet Services has witnessed very strong customer growth on its network in the current access arrangement period, in particular, the last 2-3 years.

It is not only the Victorian Government who expects a reduction in the rate of growth in new dwellings. CIE noted that the HIA expected housing starts in Victoria to decline markedly over the 2021-23 period. More recent forecasts from HIA are slightly higher than the forecasts noted by CIE, but still show a significant reduction compared to recent record highs.

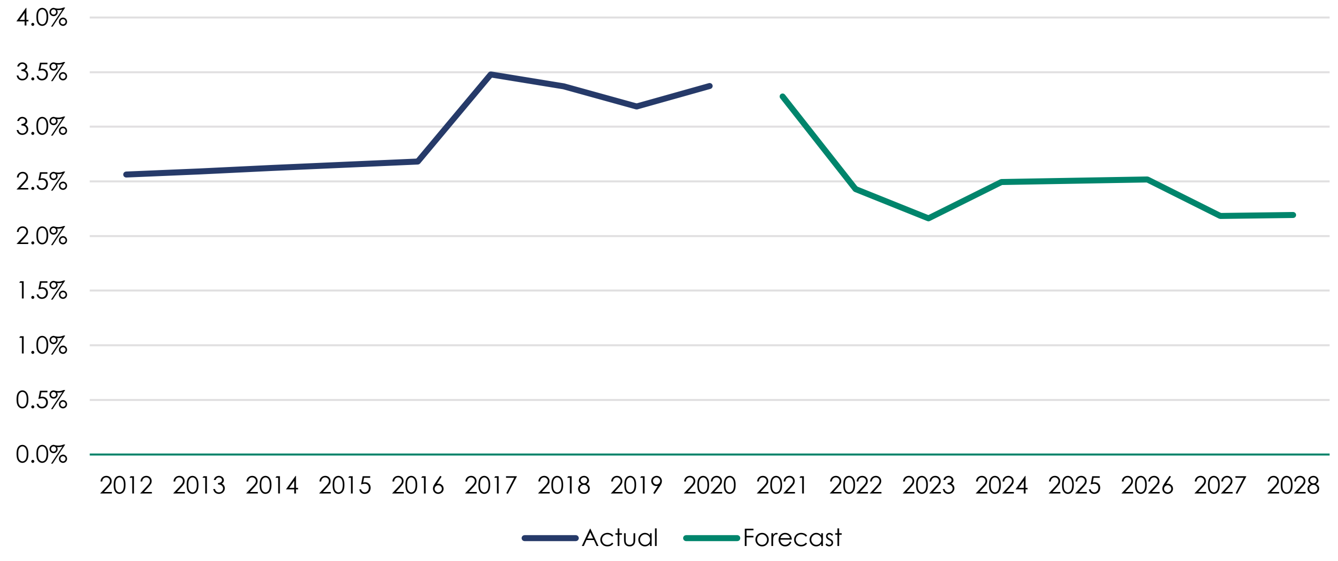
Figure 4.1: Victorian housing starts



Source: Housing Industry Association

On the basis of these two independent forecasts of housing growth, CIE's forecast customer growth in the forthcoming access arrangement period is lower than the rate of growth seen in recent years. The figure below presents the year-on-year percentage increase in occupied dwellings (a proxy for potential customers), based on the forecasts of dwelling growth in VIF2019. This reduces the dwelling stock available to connect to gas, relative to the strong growth in housing experienced in the current access arrangement period.

Figure 4.2: Year-on-year percentage change in occupied dwellings



Source: CIE

At the end of this process, the number of customers potentially able to connect to our gas network (i.e., only those dwellings in postcodes supplied by us) has been forecast.

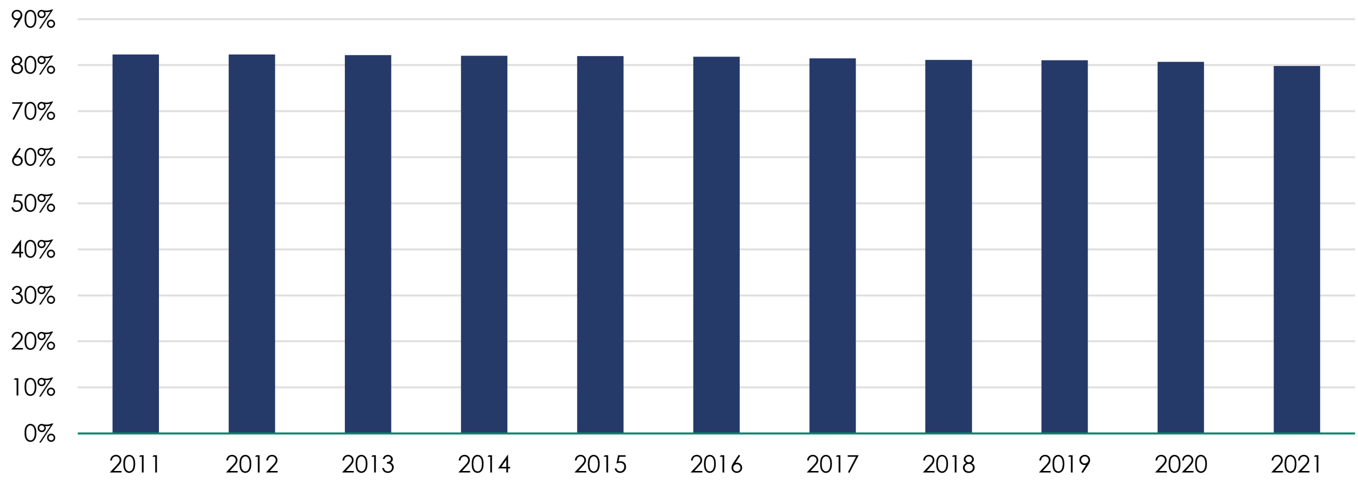
4.3.1.2. Estimating the 'penetration rate' of gas connections

Not all households in an area supplied by a gas network connect to gas. Therefore, while the forecast number of dwellings in each postcode is a useful starting point, it needs to be reduced to account for those customers who choose not to connect to gas.

CIE uses VIF2019, together with data from the Australian Bureau of Statistics (ABS),[44] to estimate the historic number of occupied dwellings in our network area. These numbers are then divided into historic residential gas customer numbers to estimate a 'penetration rate' of gas connections in our network. In other words, the penetration rate is the proportion of occupied dwellings that have a gas connection.

Excluding LGAs in which we have only a small footprint,[45] CIE calculated the average penetration rate to be around 80% and showing signs of a very slight decline over the past decade.

Figure 4.3: Average historic penetration rate in AusNet's area



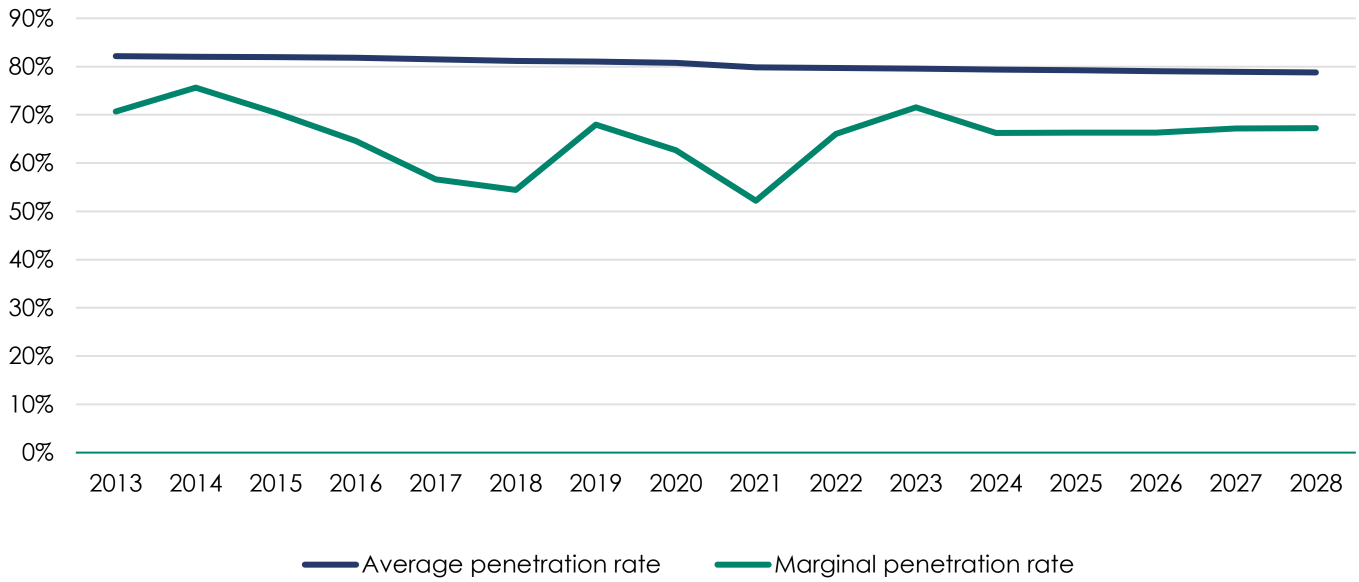
Source: CIE

[44] https://stat.data.abs.gov.au/Index.aspx?DatasetCode=BA_GCCSA (accessed July 2021).
[45] Campaspe, Darebin, Melbourne, Mitchell, West Wimmera, Whittlesea and Yarriambiack LGAs.

CIE concluded that the proportion of available dwellings that are connecting to gas has been declining slightly over the past decade, due mainly to new flats and apartments opting for an electricity-only connection.[46] This means that the 'marginal' penetration rate (i.e., the penetration rate of the most recent cohort of potential customers) is lower than the overall average penetration rate.

CIE used the results of their analysis on the penetration rates of gas to predict the likely future proportion of customers connecting to gas, assuming no changes in government policy in the area of new gas connections. This is depicted in the figure below and shows that our forecast average penetration rate of gas is in line with the historic trend.

Figure 4.4: Average and marginal penetration rates in AusNet's area (historic and forecast)



Source: CIE

4.3.1.3. Forecasting residential gas customers

Once the marginal penetration rate for each LGA has been calculated (section 4.3.1.2), it is multiplied by the projections of occupied private dwellings to derive residential gas customer forecasts for the next access arrangement period. CIE has adopted an average of the 2019 and 2020 marginal penetration rates for its forecasts. In other words, it assumes that households within each LGA will connect to gas at approximately the same rate at which households connected in 2019 and 2020.

This calculation is undertaken for both free standing houses and apartments/flats, which allows the residential consumption forecasts to reflect the differing consumption profiles of these customer types. This is explored in more detail in section 4.4.

4.3.2. Residential customer numbers

The table below summarises our residential customer forecasts over the forthcoming access arrangement period, reflecting the above methodology. Forecasts reflect net growth, that is, new connections less abolishments (permanent disconnections).

[46] CIE, p. 40.

4.3.2.1. Forecasting residential gas customers

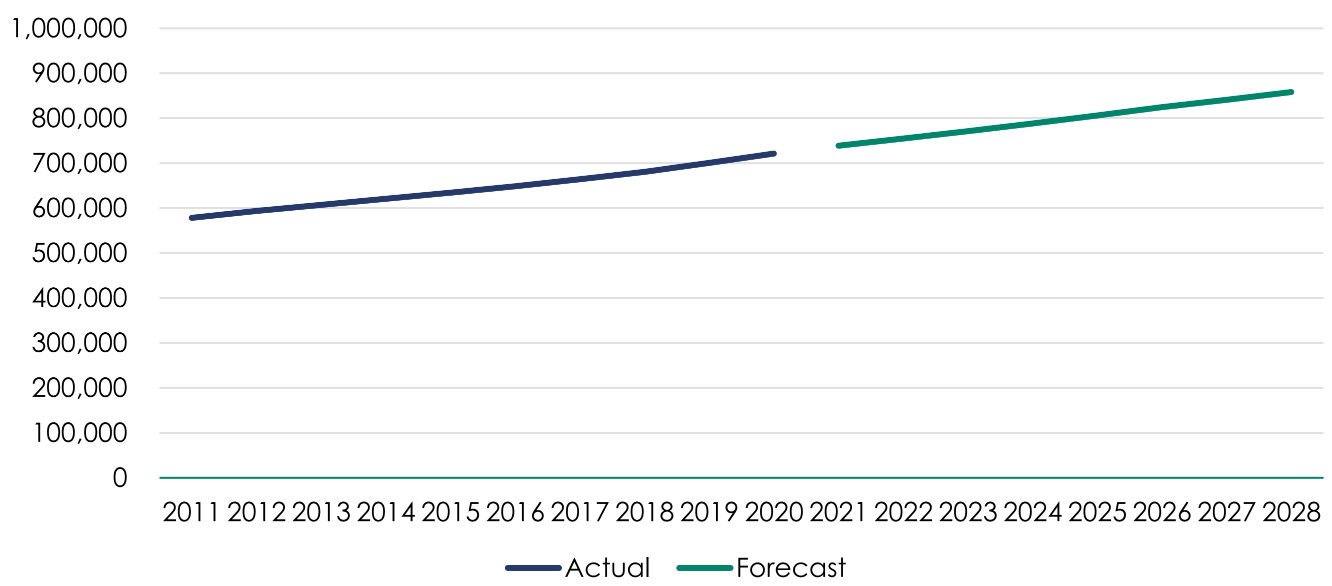
Table 4.1: Residential customer number forecast (average annual customer)

	2023-24	2024-25	2025-26	2026-27	2027-28
Residential customers	779,829	797,292	815,283	832,736	849,632
Annual growth		2.2%	2.3%	2.1%	2.0%

Source: CIE

The average annual growth rate of 2.1% over the forthcoming access arrangement period, while lower than the 2.7% in the current period, is broadly consistent with the historical trends on our network, as depicted below.[47] The main driver of the lower growth is the lower growth in housing stock, discussed in section 4.3.1.1.

Figure 4.5: Residential customer numbers



Source: CIE

4.1.1 Commercial customer forecast methodology

Commercial customers are forecast on a different basis to residential customers. Unlike household growth, there is no independent forecast of the number of businesses that will be operating in a given area.

CIE identifies two options for forecasting commercial customer growth:

1. A 'top-down' approach, which use forecasts of Gross State Product in Victoria to forecast the total number of commercial customers in our area. This forecast would then be allocated to LGAs and postcodes.
2. A 'bottom-up' approach, whereby local drivers are used to forecast customer numbers at the LGA level, and summing each LGA to derive total customers.

The second option is preferable, so long as reliable indicators at the local level are available. This is because local factors may be more reflective of growth in that area than statewide economic indicators.[48]

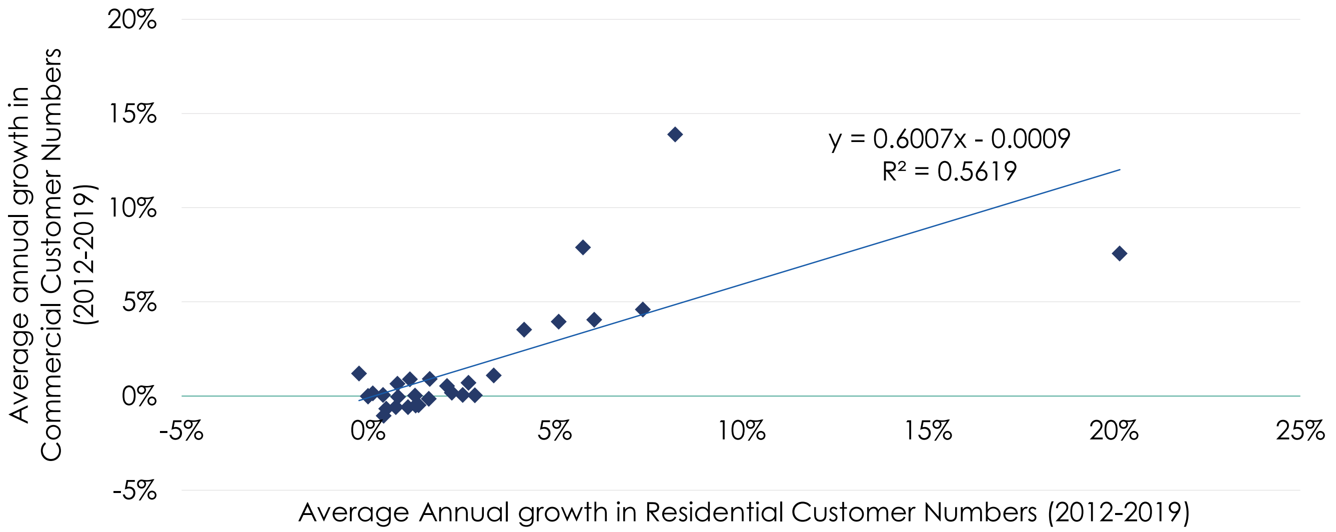
The growth in residential customers is one such local-level indicator of economic activity in an area, and given the availability of our billing database (which has information at the postcode level) a bottom-up approach was adopted by CIE.

[47] Customer numbers presented in this chapter will be lower than customer numbers reported in the annual Regulatory Information Notice (RIN) templates. This is due to different definitions of 'customers'. In the RINs, customer numbers reflect the number of connections in the network, whether they are 'active' connections currently taking gas through a commissioned meter, or simply connected to the network, but not yet an active customer. Conversely, customer numbers developed for the access arrangement information must reflect only those customers with commissioned meters, because customers who are not taking gas do not receive a network bill and therefore do not contribute to the revenue requirement. If the customer numbers in the access arrangement information were forced to align with the annual gas RINs, this would overstate the connections and demand expected to recover the revenue requirement approved by the AER.
[48] CIE, p. 80.

CIE, therefore, used the residential customer number forecast as a base and forecast how many new commercial customers would connect, given the residential growth occurring in LGAs. This same approach was used in the current access arrangement period review and accepted by the AER.

For the 2023-27 forecasts, CIE was able to establish a statistically significant relationship between the change in commercial customers and the change in residential customers (see the figure below).

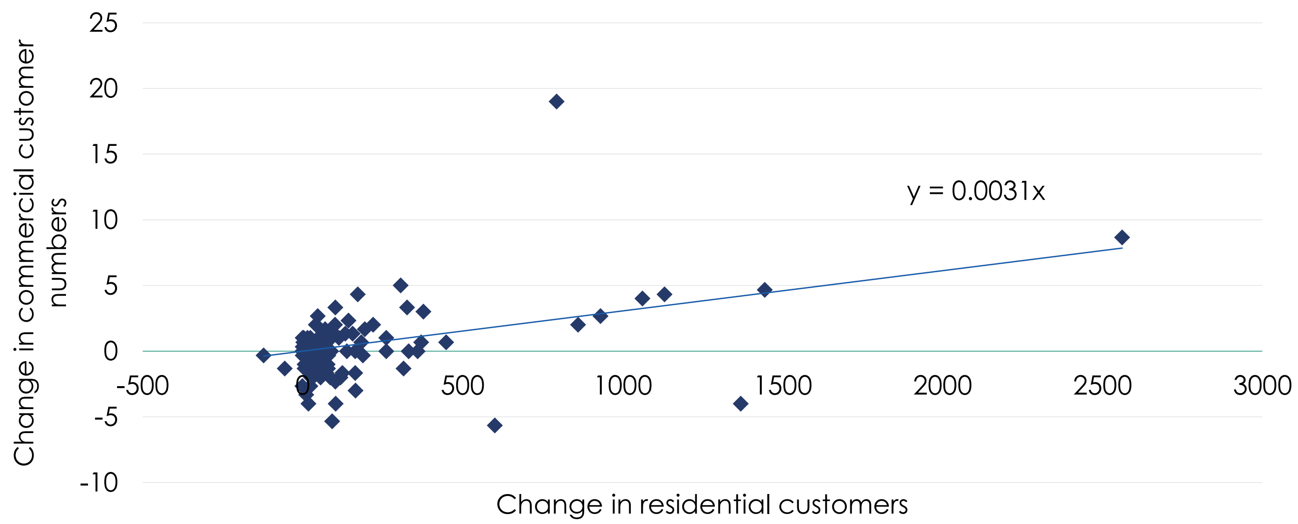
Figure 4.6: Change in commercial customers vs change in residential customers



Source: CIE

Once CIE had established a robust relationship between the growth in residential customers and commercial customers at the LGA level (above), it then calculated what this translated to for forecast commercial customer growth in each LGA. On average, across the network and the three most recent full years available of 2018-2020, CIE established that for every 1,000 new residential customers, 3.1 new commercial customers are created. This is depicted in the below chart.

Figure 4.7: Change in commercial customers vs change in residential customers 2018-20 (pooled model: across years and postcodes)



Source: CIE

AusNet

4.3.3. Commercial Customer Numbers

The table below summarises our commercial customer forecasts over the forthcoming access arrangement period, reflecting the above methodology. Forecasts reflect net growth, that is, new connections less abolishments (permanent disconnections).

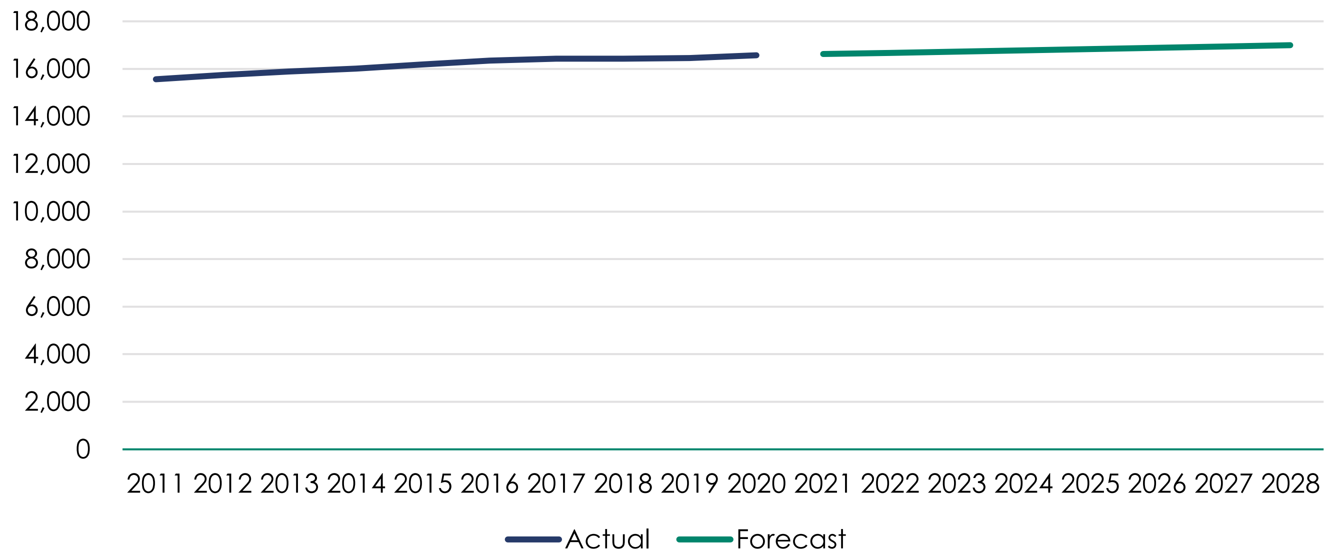
Table 4.2: Commercial customer number forecast (average annual customer)

	2023-24	2024-25	2025-26	2026-27	2027-28
Commercial customers	16,754	16,808	16,864	16,918	16,970
Annual growth		0.3%	0.3%	0.3%	0.3%

Source: CIE

The relatively flat growth in customer numbers continues the trend seen since around 2016, as presented below.[49]

Figure 4.8: Commercial customer numbers

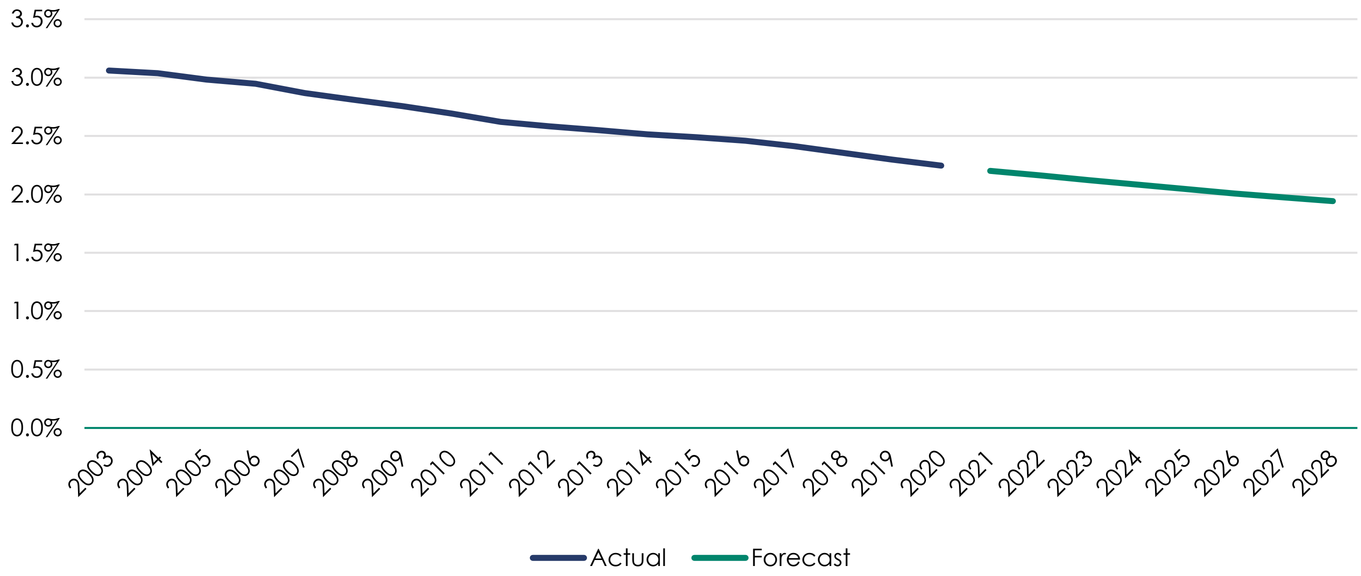


Source: CIE

The commercial customer proportion of the entire customer base has been declining over time, as the growth in commercial customers has not matched the strong growth in the residential customer base. The above commercial customer forecast results in the continuation of this trend. By the end of the forthcoming access arrangement period, commercial customers are forecast to represent fewer than 2% of the total customer base.

[49] The scale of the chart somewhat masks the variability in commercial customer connections, which is not as stable as the residential trend. For example, the commercial customer base declined by three customers in 2018, while 2021 saw unprecedented growth of ~500 customers. The commercial forecasting methodology averages out this variability.

Figure 4.9: Commercial customers as a percentage of total customers



Source: CIE

4.3.4. Gross customer connections

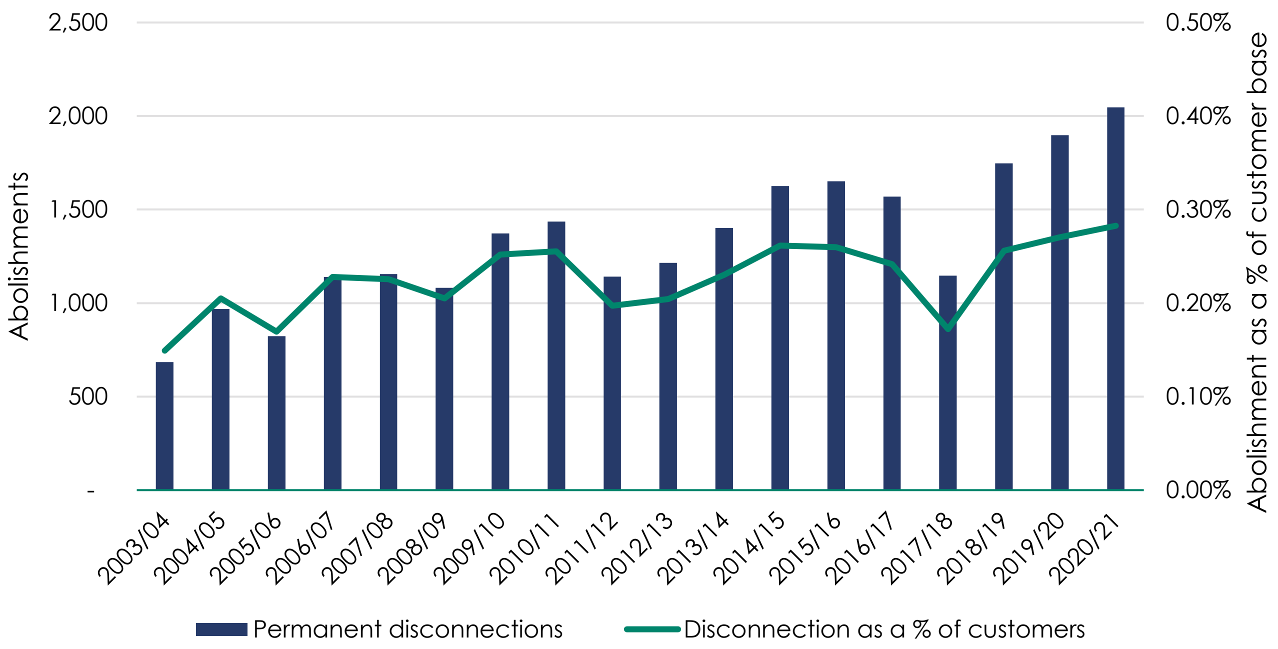
The discussion in this chapter has focussed on net growth, i.e., the growth in the total number of customers connected to the gas network. While the net growth in the customer base is important for consumption and pricing forecasts, it is also important to forecast the total (or 'gross') new connections across the period. This gross connections forecast is used to determine the amount of expenditure required to connect customers to the network.

As our forecasting methodology so far has focused on net connections, we need to add back forecast customer disconnections to produce a forecast of gross connections. In most instances, 'disconnections' are due to knocking down an existing dwelling and replacing it with one or more new dwellings on the same site. They are not usually indicative of existing gas customers deciding to permanently disconnect their gas connection and convert to an all-electric home or business.

The residential disconnection rate in our network (that is, the proportion of customers who disconnect relative to the entire customer base) has fluctuated over time but since 2013/14, has been between 0.23% and 0.28% every year except 2017/18[50] (see figure below). We have, therefore, assumed that the disconnection rate over the forecast period will reflect the rate of disconnection experienced in the last two years. We note that the last three years have exhibited growth in the disconnection rate and will continue to monitor this trend to inform the forecasts developed for our Revised Proposal.

[50] Which may be due to data issues with regard to disconnections in the month of January 2018.

Figure 4.10: Residential disconnections 2003/04-2020/21



Source: AusNet

Adding back disconnections to the annual net customer growth yields the below forecast of gross customer connections for the next access arrangement period.

Table 4.3: Gross connections 2023/24-2027/28

	2023-24	2024-25	2025-26	2026-27	2027-28
Residential connections	18,938	19,529	20,106	19,614	19,103
Commercial connections	143	145	147	145	144

Source: CIE

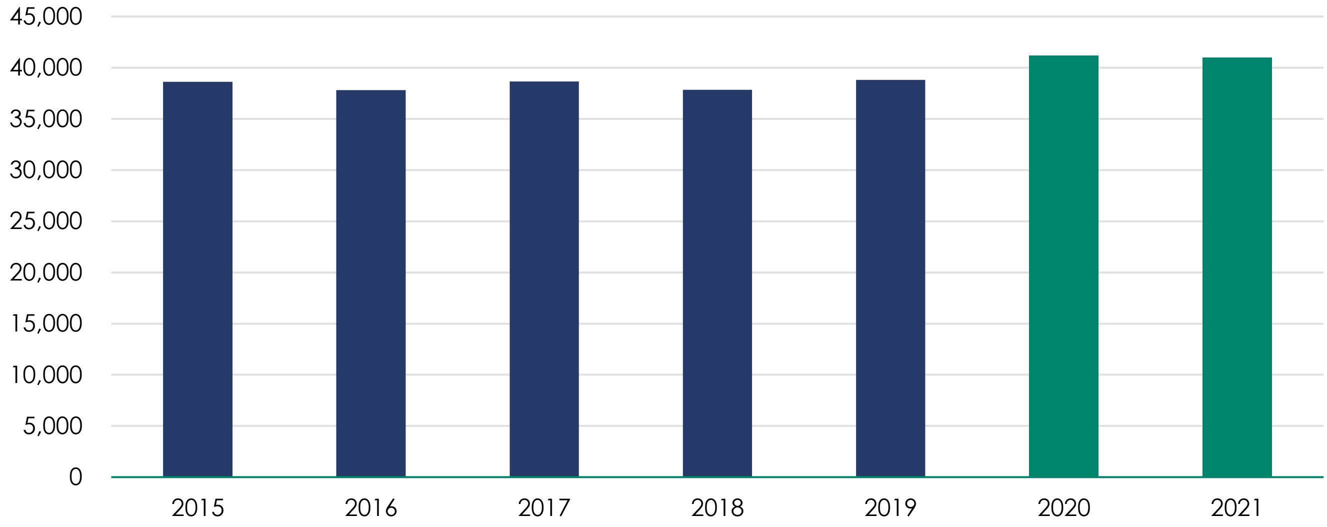
4.4. Energy consumption forecasts

AusNet Services' energy consumption forecasts are derived by multiplying the customer forecast explained in the previous section, by the average consumption per customer, for both the residential and commercial segments. This section provides an overview of the drivers of gas consumption used in CIE's model. More detail can be found in CIE's final report (Appendix 3).

4.4.1. Residential energy consumption drivers

The total volume of gas consumed by residential customers had been reasonably constant over the five years leading into the COVID-19 pandemic. Government imposed lockdowns caused a shift towards higher residential consumption (due to work from home orders) and lower business demand (due both to work from home orders and restrictions on opening). In addition, the last two years have had colder than average weather, skewing gas consumption higher than otherwise would be the case. The impact of the last two years of the pandemic and cold weather can be seen in the figure below.

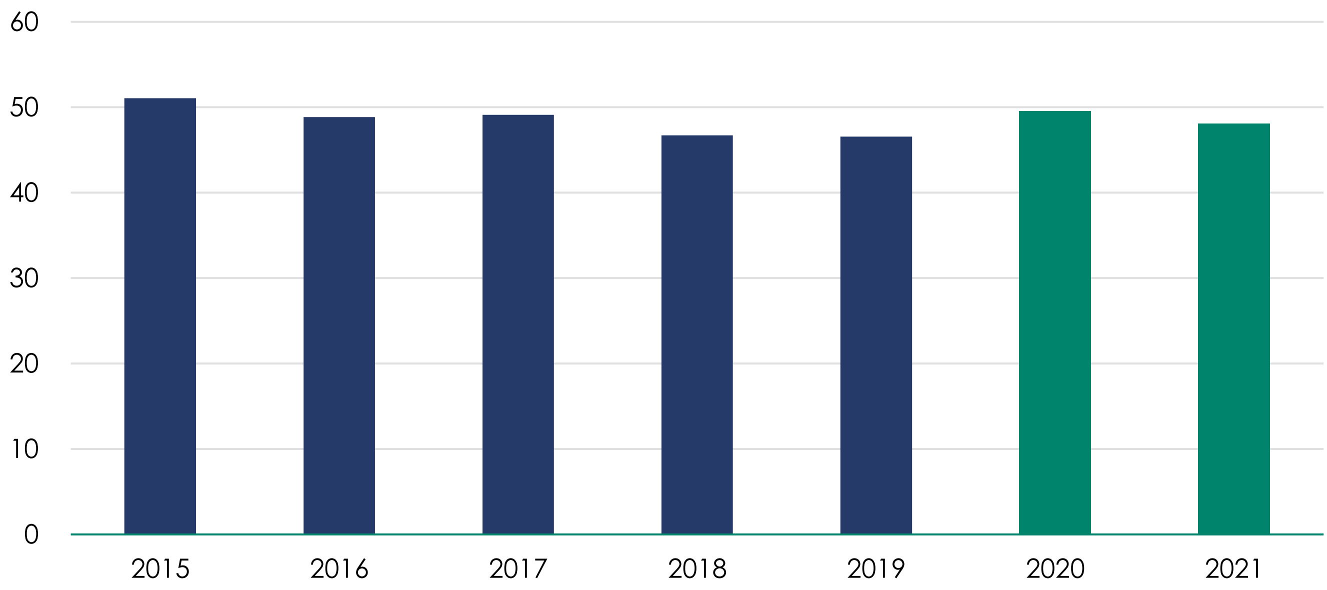
Figure 4.11: Tariff V gas consumption 2015-2021 (TJ)



Source: Annual gas RINs

The flat consumption leading into the pandemic occurred at a time of continued strong customer growth. This reflected an ongoing reduction in energy consumption per customer, which has been reversed during the last two years, as illustrated below. It is worth noting that 2015 was the most recent year with weather comparable to 2020 and 2021.

Figure 4.12: Residential gas consumption per customer 2015-2021 (GJ)



Source: AusNet

With the next access arrangement period commencing in July 2023, our forecasts have been prepared to reflect the underlying drivers of the trend before the pandemic, as well as understanding to what extent the recent uplift in energy consumption has been affected by COVID-19.

4.4.2. Energy consumption trends in the residential gas sector

Energy efficiency, fuel type and housing design

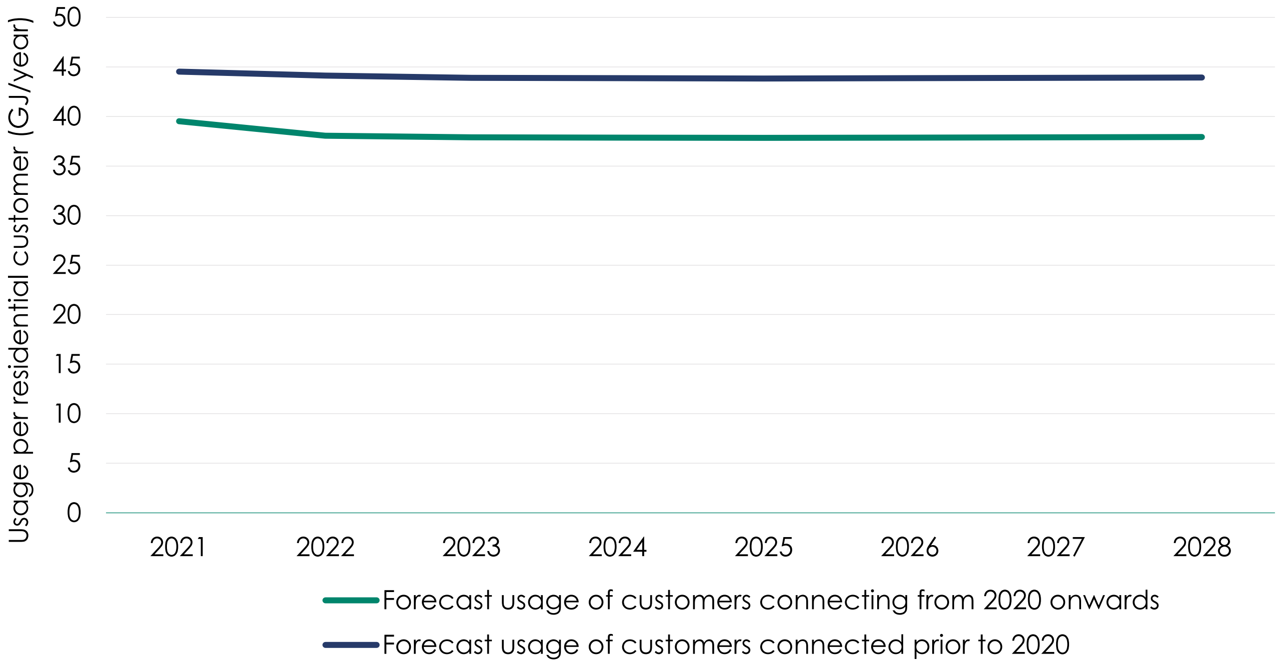
As in the electricity sector, the effect of energy efficient appliances and government policies relating to energy efficiency have contributed to new dwellings consuming less gas than older dwellings.

The continued impact of these initiatives for new customers (or existing customers replacing appliances) means that the overall average consumption per household will continue to decline over the medium to long term. To the extent that new customers use less gas than existing customers, this is an important variable to account for in energy consumption forecasts.

CIE established that residential customers in new dwellings connecting to the network use around 10% less than the average residential customer. This finding is indicative of the impact of energy efficiency, customer preferences for gas or electricity and differences in housing design, for example, whether flats and apartments are more prevalent than free standing houses.

This distinction between new and existing customer consumption profiles is factored into the forecasts. CIE calculates an average consumption per customer for both of these cohorts, with the existing customer base following one trajectory and new customers following another. This is depicted in the figure below.

Figure 4.13: Difference between consumption in new and existing dwellings

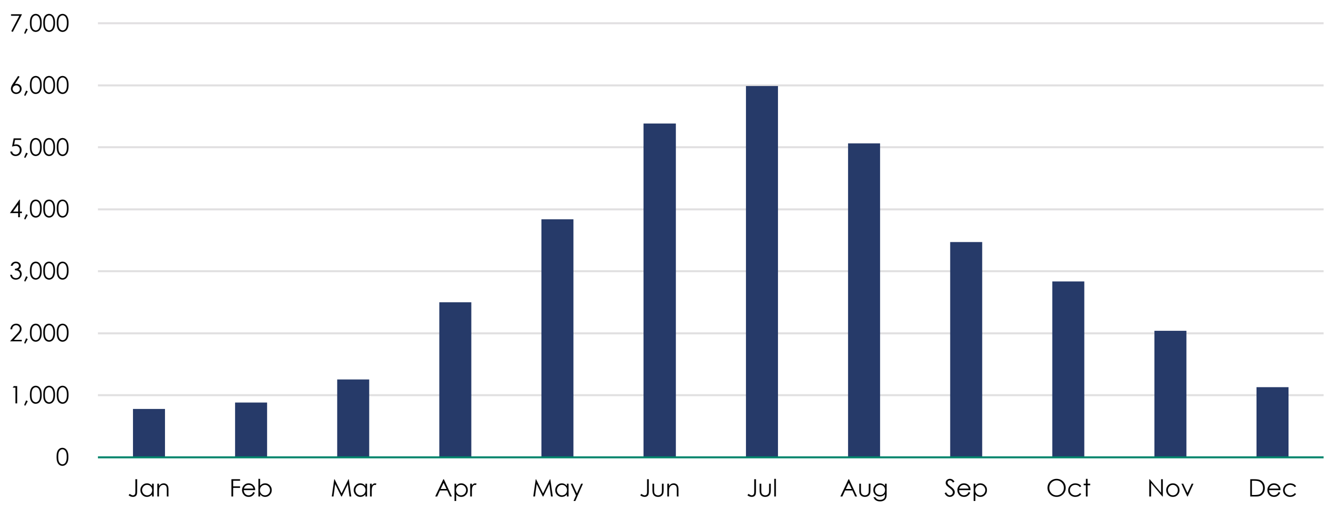


Source: CIE

Weather

Weather plays an important role in the consumption of gas, due to the impact it has on heating demand. Space heating is the largest driver of energy consumption on our network, as is clearly evident when annual gas consumption is broken down into monthly values.

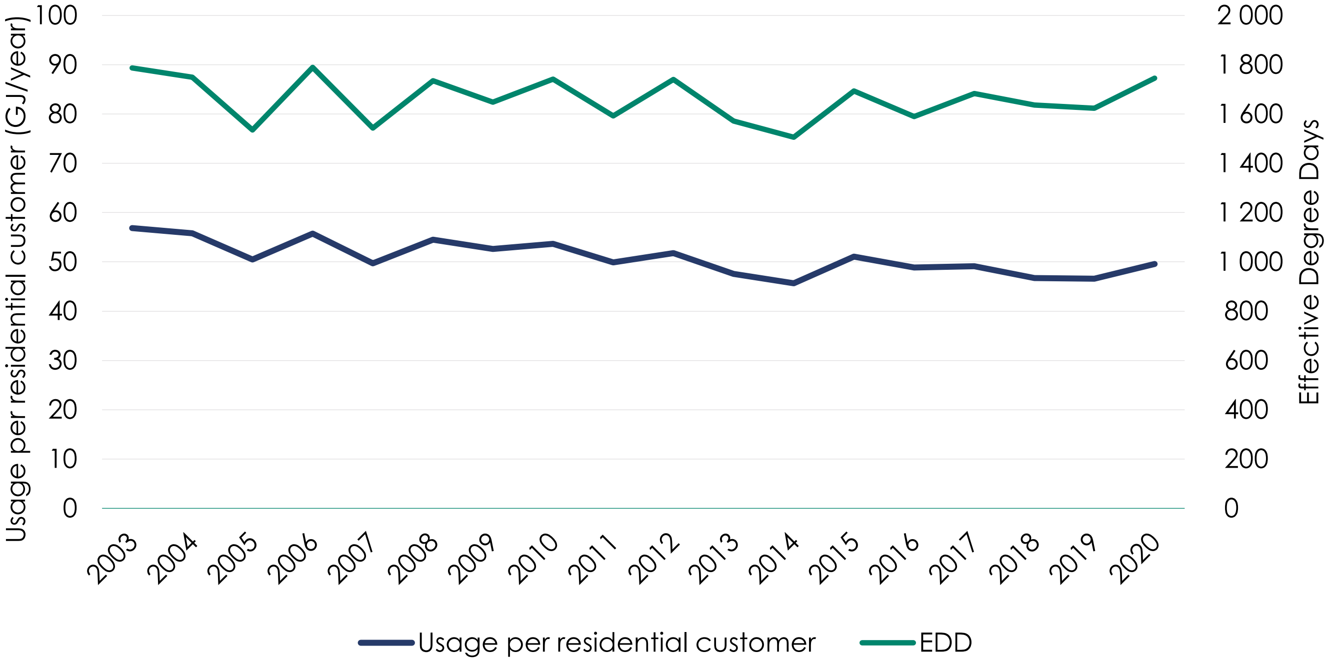
Figure 4.14: 2021 residential gas consumption by month (TJ)



Source: AusNet

Effective Degree Days is the measurement unit that we use to estimate how cold the weather is. Effective Degree Days are a common measure of weather and take into account temperature, wind and sunlight to produce a daily value of the level of 'coldness'.[51] Effective Degree Days can be correlated with gas consumption to produce an estimate of how much additional gas a customer will use for an associated increase in Effective Degree Days. As seen below, there is a strong correlation between gas consumption and Effective Degree Days.

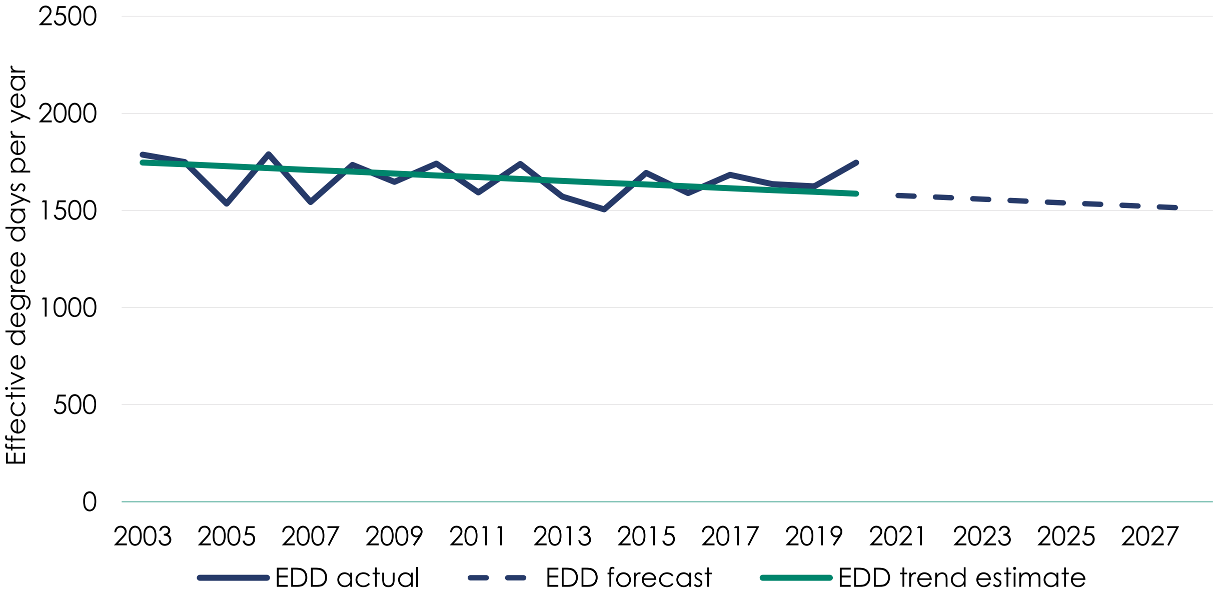
Figure 4.15: Residential gas consumption and Effective Degree Days



Source: CIE

Any trend towards fewer Effective Degree Days – that is, warmer weather – will result in lower gas consumption. CIE established that there was in fact a trend of lower Effective Degree Days over time and has projected this trend into the next access arrangement period, as shown in the figure below.

Figure 4.16: Effective Degree Days trend and forecast



Source: CIE

The forecast decline in Effective Degree Days will result in marginally lower gas consumption in the next access arrangement period, all things being equal.

[51] The higher the Effective Degree Days, the colder it is.

Gas prices

CIE incorporated a gas price variable in its formal statistical model of the drivers of gas consumption. As with other commodities, an increase in the price of gas was found to cause a decrease in the consumption of gas, based CIE's statistical analysis of past consumption and gas prices. CIE has applied this price 'coefficient' to AEMO's forecast of residential gas prices to determine the impact of future gas prices on gas consumption.

CIE also investigated the link between electricity prices and gas consumption, as in theory, when electricity prices are high relative to gas prices, customers would be expected to increase their consumption of gas compared to electricity. CIE could not, however, determine a reliable link between electricity prices and gas consumption, concluding that "using an electricity price variable directly in the estimation would lead to worse forecasts."[52] Therefore, electricity prices were not included in CIE's model.

COVID-19 pandemic

As noted earlier, the effects of COVID-19 and the associated government and societal response have had large impacts on gas consumption. This is particularly so for residential gas customers who are working from home, as they are more likely to increase their usage related to space heating.

Section 3 of CIE's report contains a detailed analysis of the impact of COVID-19 on gas consumption. The analysis was hampered due to the lack of granularity in gas meter reads – unlike electricity in Victoria which is dominated by smart meters, gas meters are typically read on a 60 day cycle. This makes it more difficult to assess the impact of changes immediately before and after COVID restrictions/policies more difficult to assess.

It should also be noted that CIE's analysis was undertaken in mid-2021 so did not have the benefit of including the conditions which prevailed during the 2021 winter-spring lockdowns.

CIE's statistical models[53] found that COVID-19 had some impact on gas demand but its models were not conclusive as to the magnitude of the impact. Of interest, CIE's analysis suggested an increased weather effect during lockdown – in other words, that customers used more gas for a given Effective Degree Day than they did before the pandemic. So not only would gas customers consume more gas when weather was the same as before the pandemic, but would be more sensitive to colder weather than they were before.

The impact of COVID-19 on gas consumption was largely related to lockdowns and the policies imposed in connection with those lockdowns (e.g., work from home mandates and business closures). Given the unlikelihood of lockdowns enduring in the next access arrangement period, CIE's model assumed that by 2023, the pandemic would not affect gas consumption and only the drivers that existed prior to the pandemic and new drivers would influence the forecasts.

Impact of accelerating energy efficiency and appliance switching

The non-COVID drivers explained above – energy efficiency, housing design, weather and gas prices can all be incorporated into CIE's statistical model, because there is a long history of data to 'train' the model on. However, historic trends and correlations are not adequate where the future is not expected to reflect history. This is an important consideration for two crucial drivers of future gas consumption: accelerating energy efficiency and appliance switching.

As CIE notes:

> *Our model will implicitly include the effects of appliance switching and energy efficiency improvements on demand through the time trend. However, the time trend is limited in accounting for these effects because:*
>
> - *it models a linear trend in usage, and thus cannot extrapolate an increasing pattern of appliance switching if that was evident historically, and*
> - *the time trend will account for appliance switching only insofar as it has occurred historically, and will not be able to account for an increase in the rate of appliance switching driven by factors not accounted in the model.*[54]

There is strong reason to expect that both energy efficiency and appliance switching will accelerate into and during the next access arrangement period. The Victorian Government, for example, foreshadows that its *Victorian Energy Upgrades* program will reduce gas consumption by nine per cent in 2025.[55] AEMO, in its 2021 GSOO, noted that "Increasing investments in energy efficiency and fuel-switching are forecast to lower consumption, moderating the growth that will naturally occur through new gas connections."[56]

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[52] CIE, p. 59.
[53] CIE tested both a linear model and a log model, refer CIE, p. 23.
[54] CIE, p.68.
[55] https://www.energy.vic.gov.au/energy-efficiency/victorian-energy-upgrades/about-the-program (accessed 31 Mar 2022).
[56] Australian Energy Market Operator (AEMO), 2021, *Gas Statement of Opportunities*, p. 20.

To account for these expectations of accelerating energy efficiency and appliance switching which are not captured in its model, CIE incorporated a downwards post-model adjustment to its gas consumption forecasts. Rather than calculating its own adjustment, CIE considered that the assumptions in AEMO's 2021 GSOO were a reliable, publicly available and independent source that it could apply to our forecast gas consumption. While AEMO's GSOO assumptions are Victoria-wide, there is no evidence to suggest that its assumptions would not be appropriate for our network.

AEMO's assumptions for the impact of energy efficiency and appliance switching are contained in the table below.

Table 4.4: AEMO 2021 GSOO adjustments for energy efficiency and appliance switching

Calendar year	Total annual consumption (PJ/yr)	Impact of appliance switching (PJ/yr)	Impact of appliance switching (%)	Impact of energy efficiency (PJ/yr)	Impact of energy efficiency (%)
2021	126.0	0.1	0.0	1.3	1.0
2022	127.2	0.5	0.4	3.5	2.7
2023	128.6	1.1	0.8	6.1	4.7
2024	130.1	1.6	1.3	8.7	6.7
2025	131.8	2.2	1.7	10.5	8.0
2026	133.6	2.7	2.0	11.1	8.3
2027	135.6	3.1	2.3	11.1	8.2
2028	137.5	3.6	2.6	11.0	8.0

Source: CIE

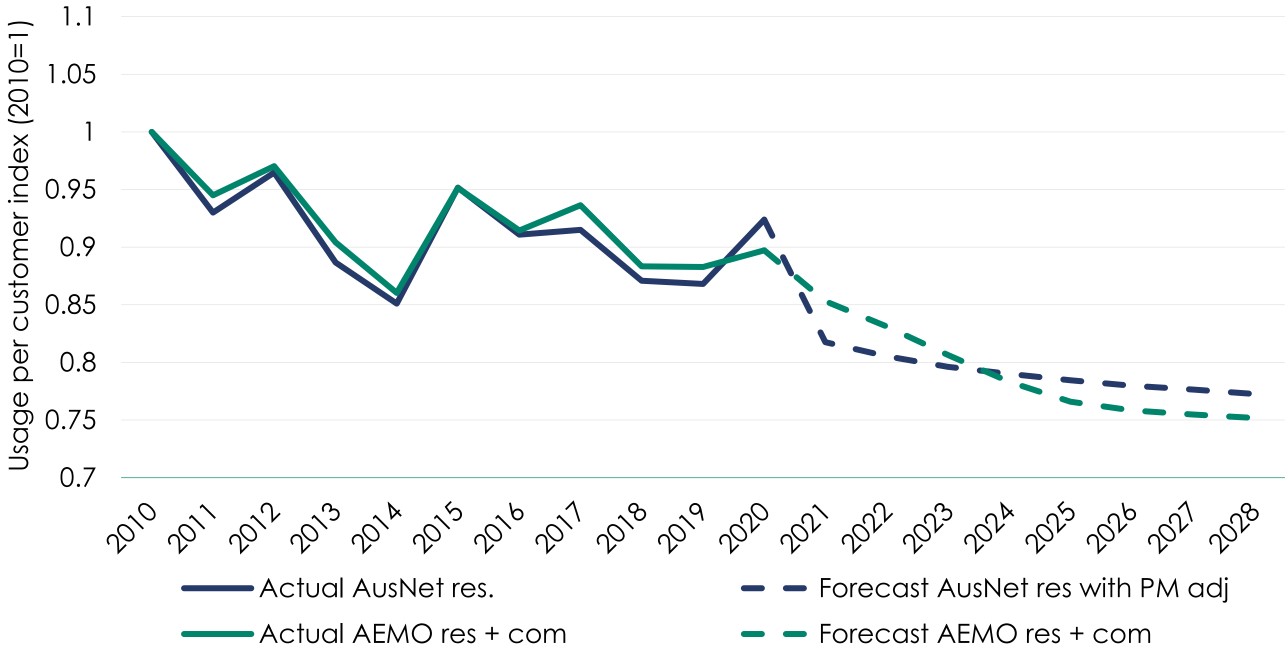
CIE adopted the percentage impacts in the above table and applied these to its modelled energy consumption forecasts. For example, it reduced its modelled forecasts by 2.6% for the impact of accelerated appliance switching and by 8.0% for the impact of accelerated energy efficiency.

To test whether these post-model adjustments were reasonable, CIE compared its residential forecasts with AEMO's forecasts of Tariff V (residential and small commercial) consumption.[57] Due to the different scales (AEMO's forecast was statewide Tariff V consumption whereas CIE's forecast was our residential consumption), CIE converted the comparison into an index.

As can be seen below, with the post model adjustment is included, CIE's forecast reduction in gas demand is close to AEMO's, whose forecast includes the impact of accelerated energy efficiency and appliance switching. This is to be expected, because as already noted, CIE's model does not take account of these accelerating drivers of demand. If the post-model adjustment was excluded, CIE's forecast would be higher and therefore, further away from AEMO's. The key difference in the forecast profiles is 2021, of which CIE notes that its forecast is more recent and therefore reflects more up-to-date information about usage per customer and the effect of COVID-19.

[57] AEMO's 2021 GSOO did not provide separate forecasts of residential and small commercial demand.

Figure 4.17: Comparison of CIE and AEMO forecasts



Source: CIE

The above finding supports our view that the post-model adjustment applied by CIE is appropriate and is producing the best estimate of future gas consumption.

4.4.3. Residential energy forecast

CIE's methodology resulted in the following forecast of residential gas consumption over the forthcoming access arrangement period.

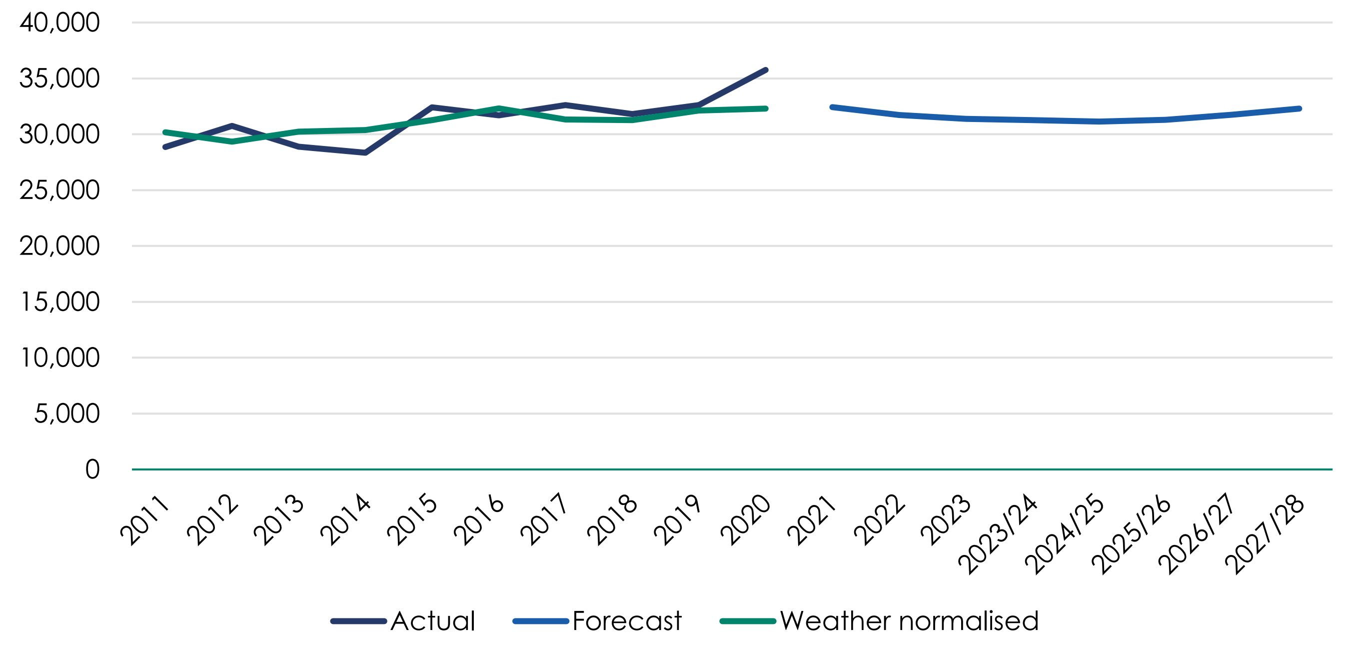
Table 4.5: Residential gas consumption forecast (TJ)

	2023-24	2024-25	2025-26	2026-27	2027-28
Residential gas usage	31,255	31,135	31,298	31,747	32,284

Source: CIE

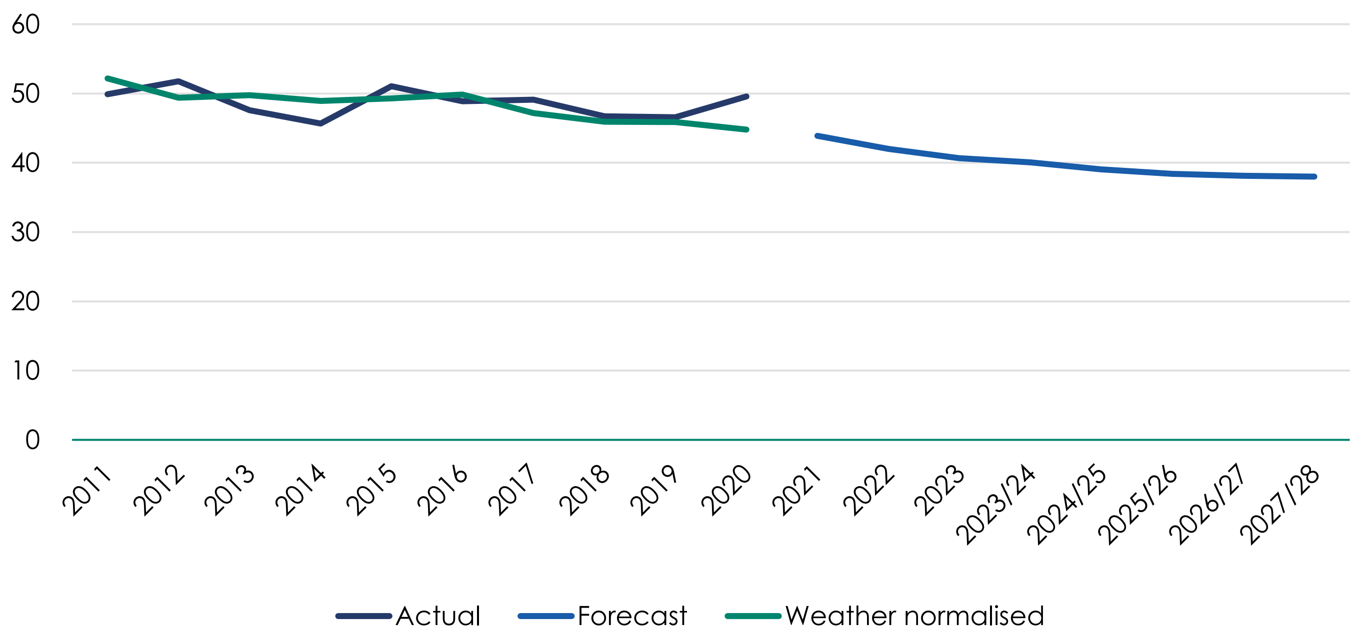
The figures below show CIE's forecasts in the context of the historical trends seen in our network, both for total residential consumption and for residential consumption per customer. Weather normalised historical data has been presented to provide a better picture of the underlying trend, once the impact of colder/warmer years is taken into account.

Figure 4.18: Residential gas consumption (TJ)



Source: CIE

Figure 4.19: Residential gas consumption per customer (GJ)



Source: CIE

4.4.4. Commercial energy forecasting methodology

The model used to forecast commercial gas consumption is very similar to that used to forecast residential gas consumption. Of the key drivers explained above, only the difference between free standing houses and flats/apartments is absent in the commercial model.

As CIE notes, however, it is not just the overall quantity of gas consumed by the average commercial customer which is different from residential customers, but the *distribution of usage per customer* is far greater for commercial customers. This is demonstrated below, which shows that the 99th percentile of commercial usage per customer is 425 times the magnitude of the 20th percentile, whereas that ratio in the residential class is only 7 times.

Table 4.6: Distribution of annual usage per customer by tariff class

Percentile of usage in class	Residential (MJ/yr)	Commercial (MJ/yr)
20th	52	33
40th	90	105
60th	126	256
80th	173	758
90th	214	1,647
95th	252	3,506
99th	345	14,115

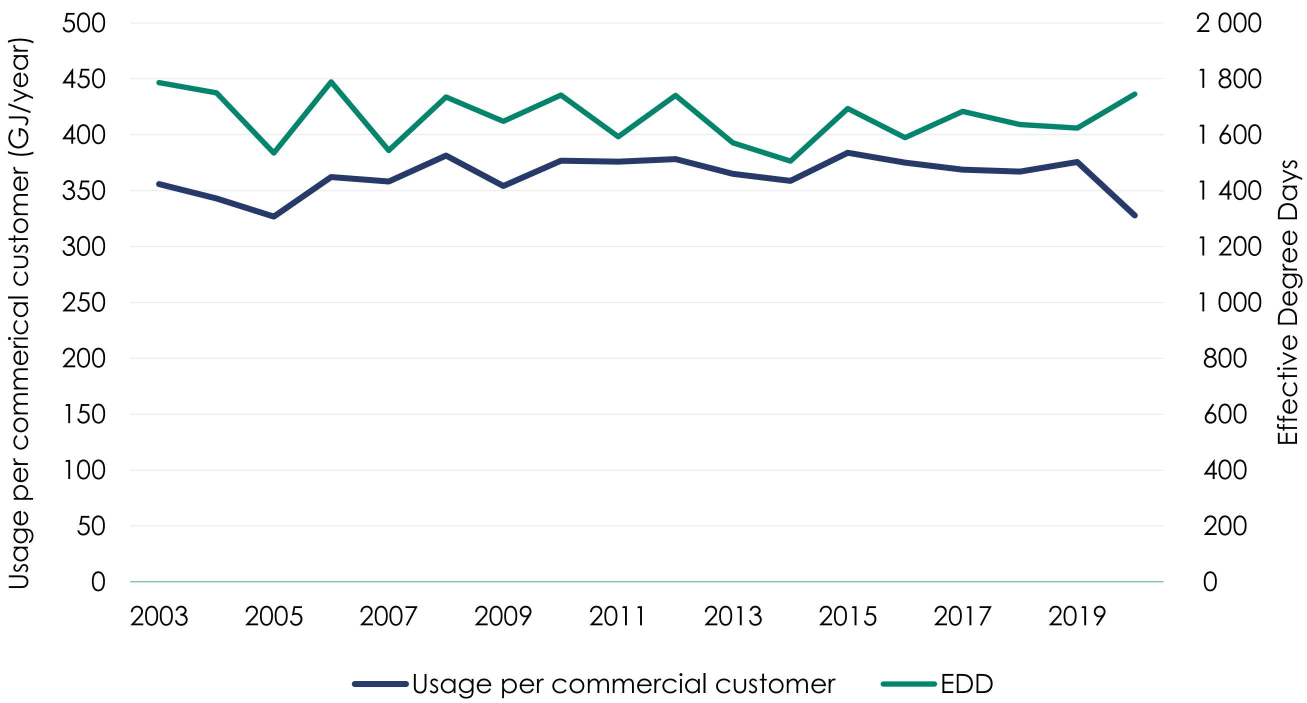
Source: CIE

The above table has been included because while this chapter refers to the 'average' commercial customer, it is important to keep in mind that the commercial segment is far from a homogenous group.

As already noted, the methodology for forecasting commercial consumption is very similar to that of residential consumption. Some of the key differences in terms of the analysis of the trends and drivers include:

- The impact of COVID-19 on commercial demand has been much more pronounced than in the residential sector. One of the clearest ways to depict this is to show the average consumption per commercial customer compared to Effective Degree Days over time. Despite the much colder than average conditions in 2020, commercial demand declined sharply:

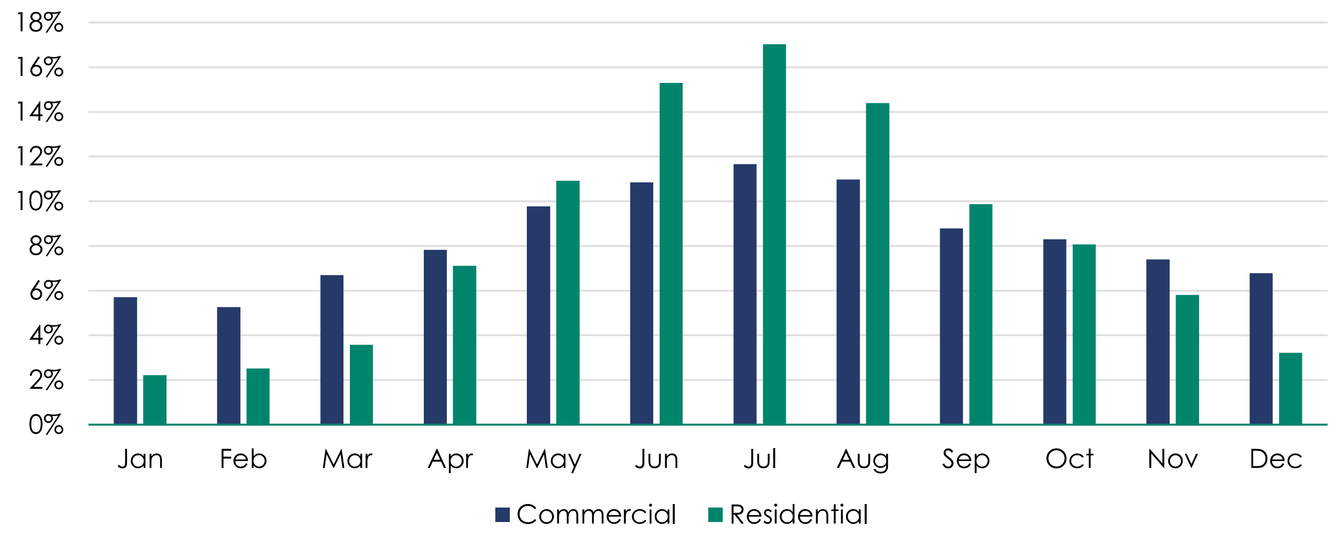
Figure 4.20: Commercial consumption per customer and Effective Degree Days over time



Source: CIE

- While new commercial customers consume less gas on average than existing customers, the difference is not as large as it is in the residential sector. New commercial customers use, on average, around 5% less than existing customers (it was around 10% in the residential segment).
- Commercial customers, on average, are less sensitive to weather conditions than residential customers. That is, the proportion of gas consumption that changes with colder weather is far less in the commercial sector. This is demonstrated in the figure below, which shows the proportion of annual gas consumption delivered to the residential and commercial sectors in each month. Compared to the residential sector, commercial customers have a much flatter usage profile throughout the year.

Figure 4.21: Percentage of annual gas consumption delivered by month



Source: AusNet

The above points explain some of the key differences in the residential and commercial forecasting methodology. Regarding the post-model adjustment for energy efficiency and appliance switching, CIE applied the adjustment to commercial consumption as it did for residential consumption. AEMO's adjustment, which CIE adopted in percentage terms, applied across the residential and small commercial sectors, so an equivalent adjustment to commercial consumption is in line with AEMO's methodology. Further, the Victorian Energy Upgrades are targeted at both residential and commercial sectors, which provides further support for applying the post-model adjustment both customer groups.

4.4.5. Commercial energy forecast

CIE's methodology resulted in the following forecast of commercial gas consumption over the forthcoming access arrangement period.

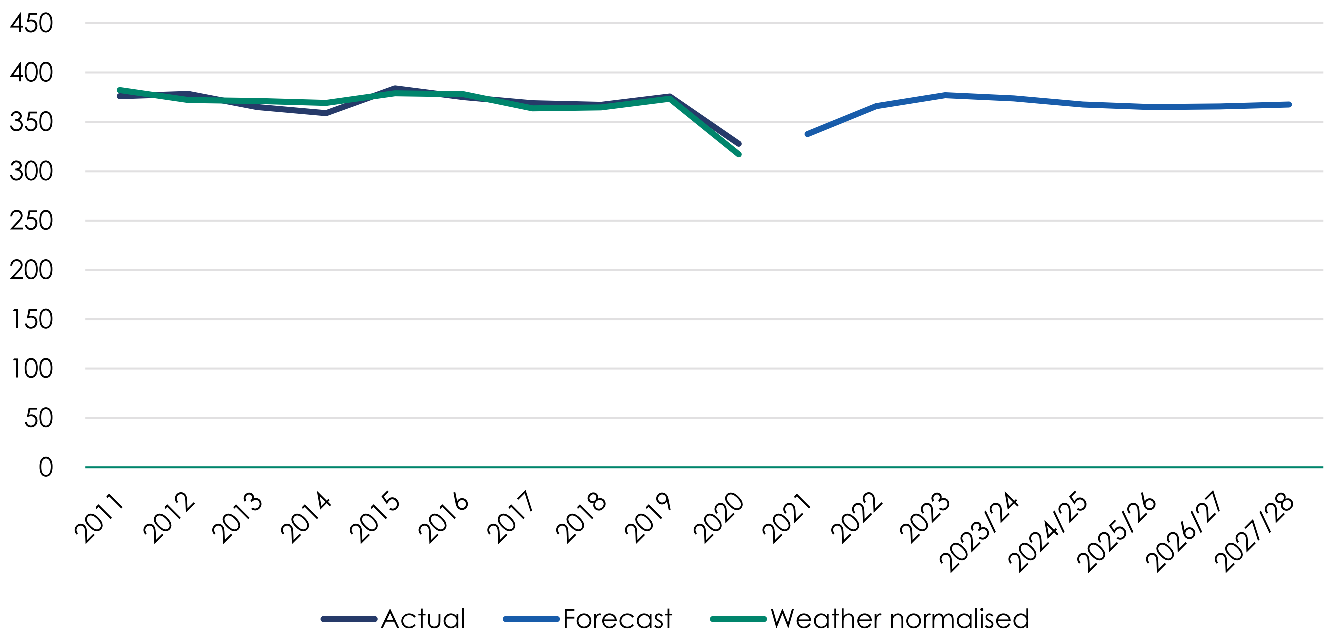
Table 4.7: Commercial gas consumption forecast (TJ)

	2023-24	2024-25	2025-26	2026-27	2027-28
Commercial gas usage	6,261	6,180	6,156	6,188	6,237

Source: CIE.

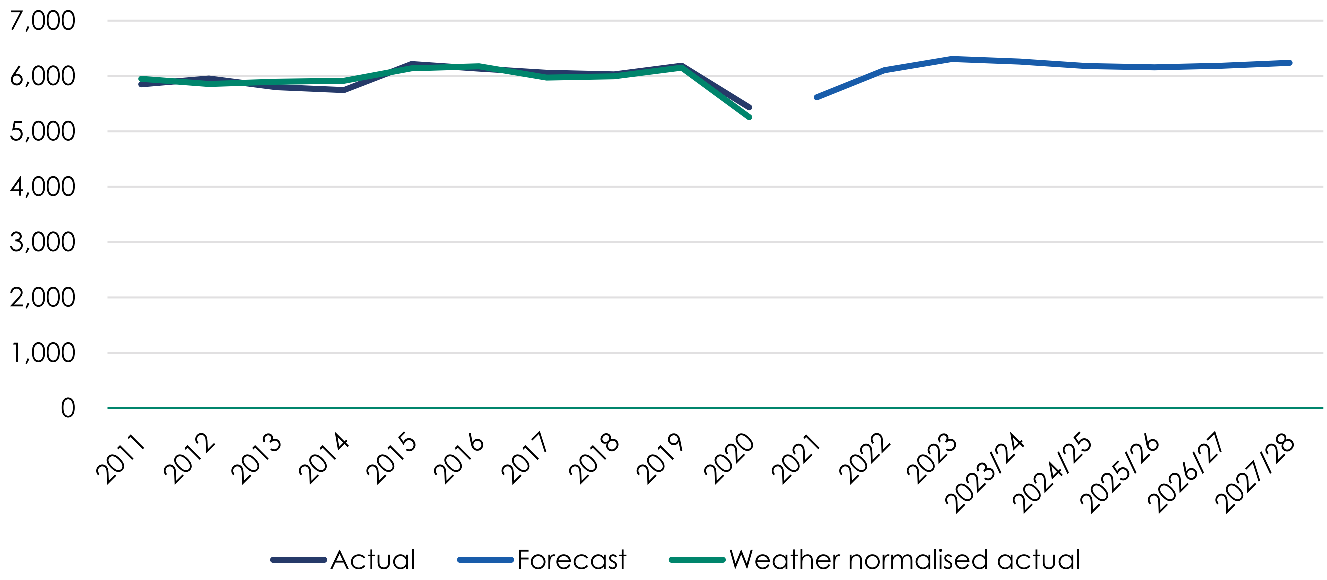
The figures below show CIE's forecasts in the context of the historical trends seen in our network, both for total commercial consumption and for commercial consumption per customer on our network. While weather normalisation of consumption is not as important in the commercial sector compared to the residential sector, we have presented this information for completeness.

Figure 4.22: Commercial gas consumption (TJ)



Source: CIE

Figure 4.23: Commercial gas consumption per customer (GJ)



Source: CIE

4.5. Large customer demand forecasts (Tariff D and M)

4.5.1. Tariff D and M

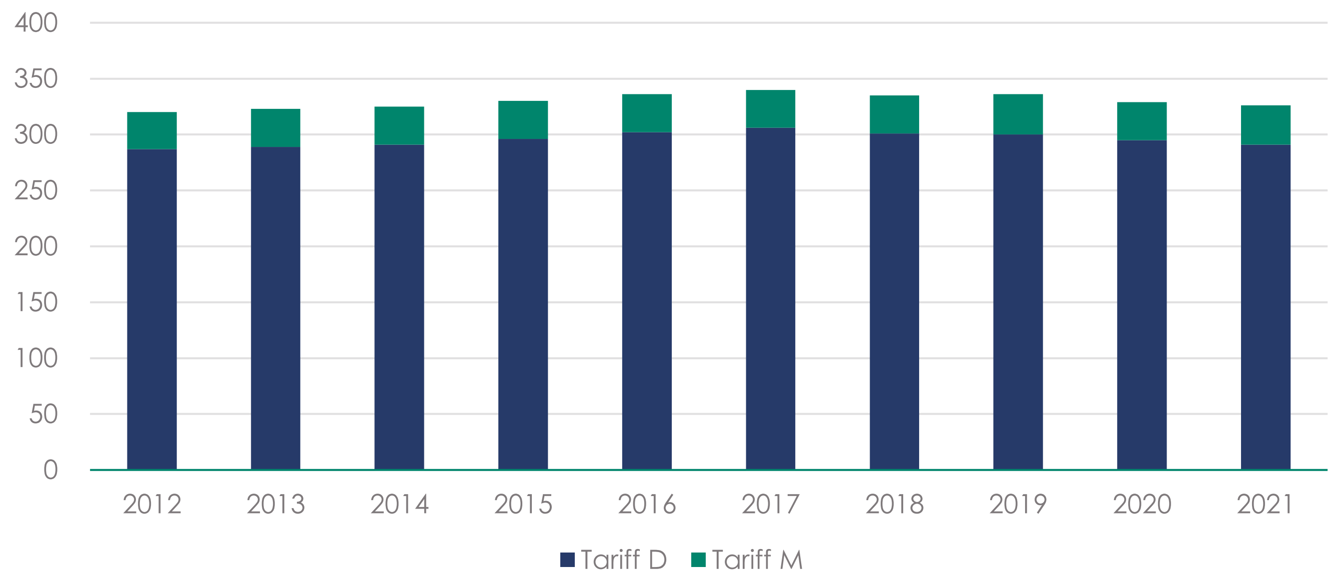
Tariff D and Tariff M customers are gas consumers who consume either more than 10,000 GJ per annum, or more than 10 GJ in one hour. These are typically large industrial customers, such as manufacturers, processers, hospitals, etc. Tariff D and Tariff M customers are not billed on the basis of their overall consumption, as is the case with residential and commercial customers (the Tariff V customer group). Rather, these customers are charged based on the peak demand for gas in any one hour (their maximum hourly quantity, or MHQ).

Because of the way these customers are charged, forecasting overall consumption is not required. Rather, it is the Tariff D and Tariff M MHQ which needs to be forecast.

4.5.2. Customer numbers

At the end of 2021, there were 291 Tariff D customers and 35 Tariff M customers. This represents a small decline compared to the number of large customers connected to the network five years ago, however, it is not out of step with a broader historical average.

Figure 4.24: Tariff D and Tariff M customer numbers



Source: Annual gas RINs

Because Tariff D and Tariff M customers are not levied a fixed charge, forecasting the number of these customers in the forthcoming access arrangement period is not required.[58] Furthermore, there is no expenditure associated with connecting new Tariff D and Tariff M customers that is not funded by the customers themselves.

Any expenditure associated with the provision of assets to enable the connection is therefore borne by the customer, either through a customer contribution, separate charges (Tariff D) or the Haulage Reference Service charge (Tariff M).

While representing just 0.04% of the customer base, these customers accounted for 42% of the energy that flowed through our gas distribution network. As explained in the preceding section, these customers are not charged on the basis of their total volume of gas consumed – rather they are charged on the basis of their MHQ.

4.5.3. MHQ Forecasts

To develop MHQ forecasts, CIE have used a top down approach, whereby the forecast change in MHQ over the access arrangement period is derived from AEMO's industrial gas consumption forecasts as set out in the 2021 GSOO. The alternative would be to attempt to forecast MHQ from the bottom up. That is, develop a model that estimates the drivers of MHQ and attempt to forecast these drivers and the continued relationship they have on MHQ.

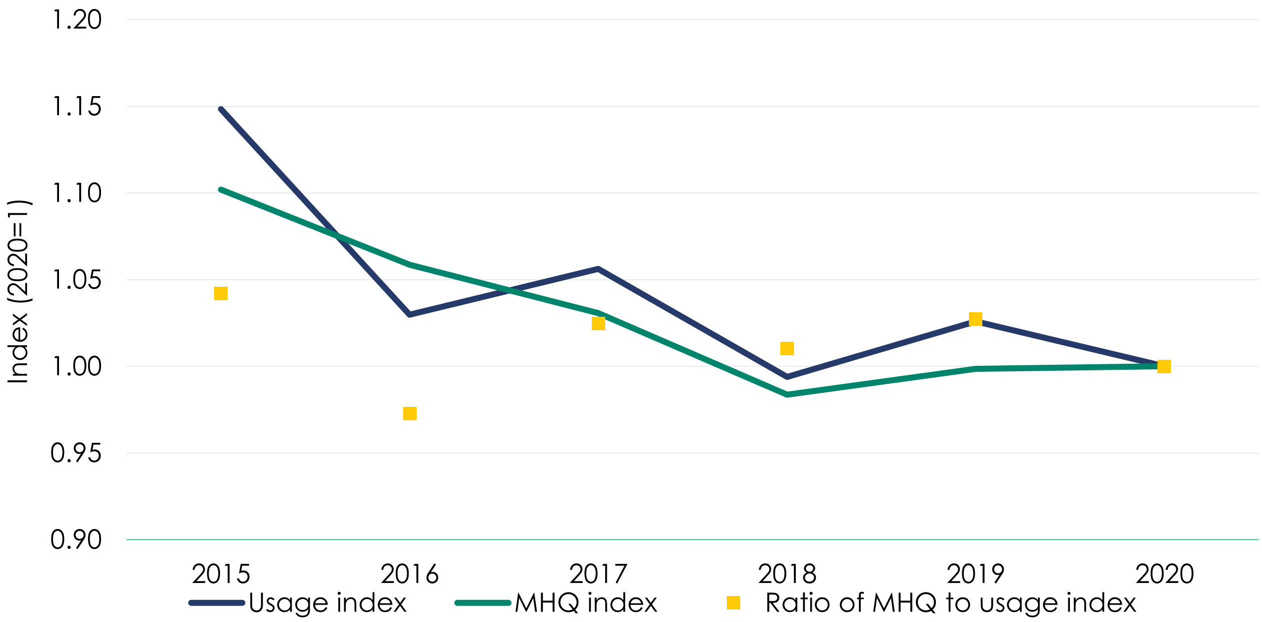
The proportion of the revenue requirement that is recovered from MHQ forecasts is around 1%. So long as a simpler, top down approach to forecasting MHQ can be found to be an accurate predicter of actual MHQ, a top down methodology is preferable to a building a time consuming and costly bottom up model.

As in the 2008-12 and 2013-17 access arrangement periods, CIE has determined that the recent MHQ of our industrial customers is strongly correlated with the same customers' total gas consumption. That is, the percentage change in

[58] For this reason, and to make reconciling numbers easier, the customer numbers presented in this section reconcile to the annual RINs. This is different to Tariff V residential and small commercial customer numbers, which as previously explained, cannot both (1) reconcile to the annual RINs and (2) correctly calculate expected revenue.

total gas consumption is a good estimator for the percentage change in MHQ. This relationship can be seen in the below chart, where 2015-2020 MHQ and consumption are converted to an index to see how closely they track each other. The dots in the chart show that in all years, the ratio of MHQ to total consumption is close to 1.

Figure 4.25: Indexes of MHQ and tariff D usage since 2015

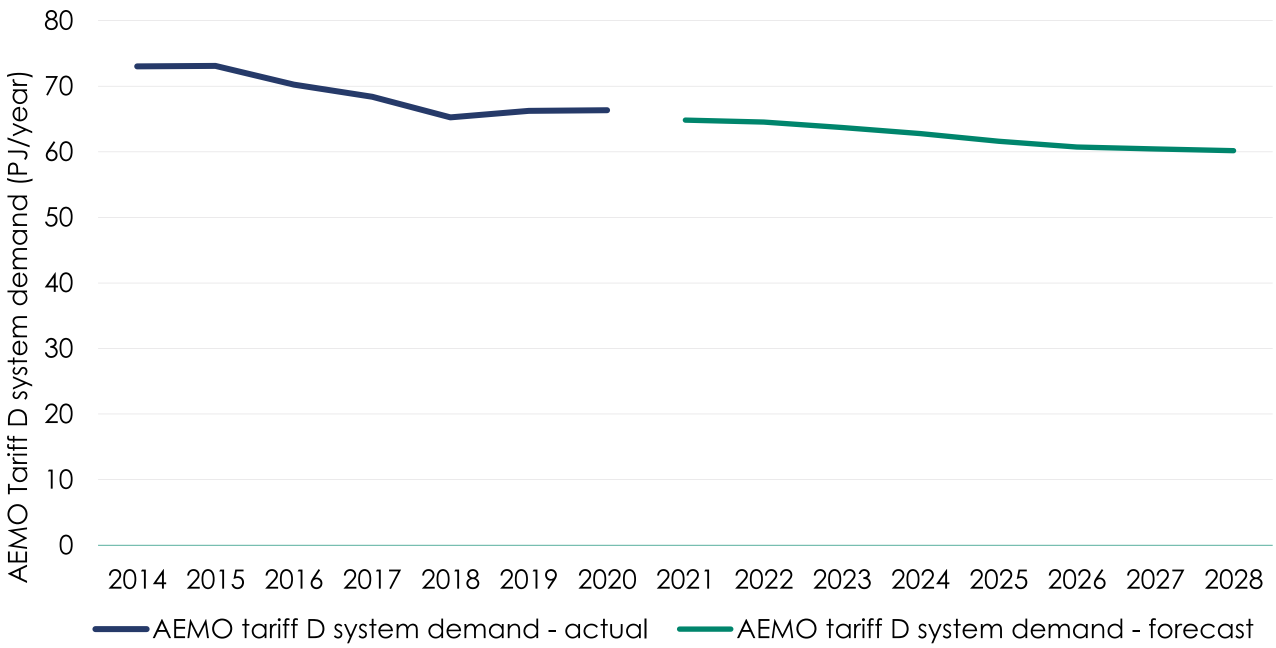


Source: CIE

Given that (1) changes in MHQ are closely correlated with changes in industrial gas consumption and (2) AEMO produces an independent forecast of industrial gas consumption, AEMO's forecast is a good candidate for forecasting AusNet Services' MHQ on a top down approach. That is, if AEMO forecasts industrial consumption to change by a certain percentage over the access arrangement period, it is reasonable to estimate that our MHQ will change by the same percentage.

For its forecasts, CIE concluded that it was appropriate to project MHQ for tariff D and M using the AEMO projections of total tariff D usage in the Central scenario of its 2021 GSOO, below.

Figure 4.26: AEMO industrial total usage actuals and forecast



Source: CIE

Consistent with the approach taken to developing the forecasts for the previous GAAR access arrangement period, we have not made a separate adjustment for the closure of any large business customers. Anticipated closures would already have been accounted for in AEMO's projections of total industrial usage that drives the forecasts of MHQ.

Applying the approach described above, our forecast of Tariff D and Tariff M MHQ are shown in the following table.

Table 4.8: Forecast Tariff D and Tariff M MHQ (GJ)

	2023-24	2024-25	2025-26	2026-27	2027-28
Tariff D	6,808	6,696	6,583	6,522	6,493
Tariff M	188	185	182	180	179
Total MHQ	**6,996**	**6,881**	**6,765**	**6,702**	**6,672**

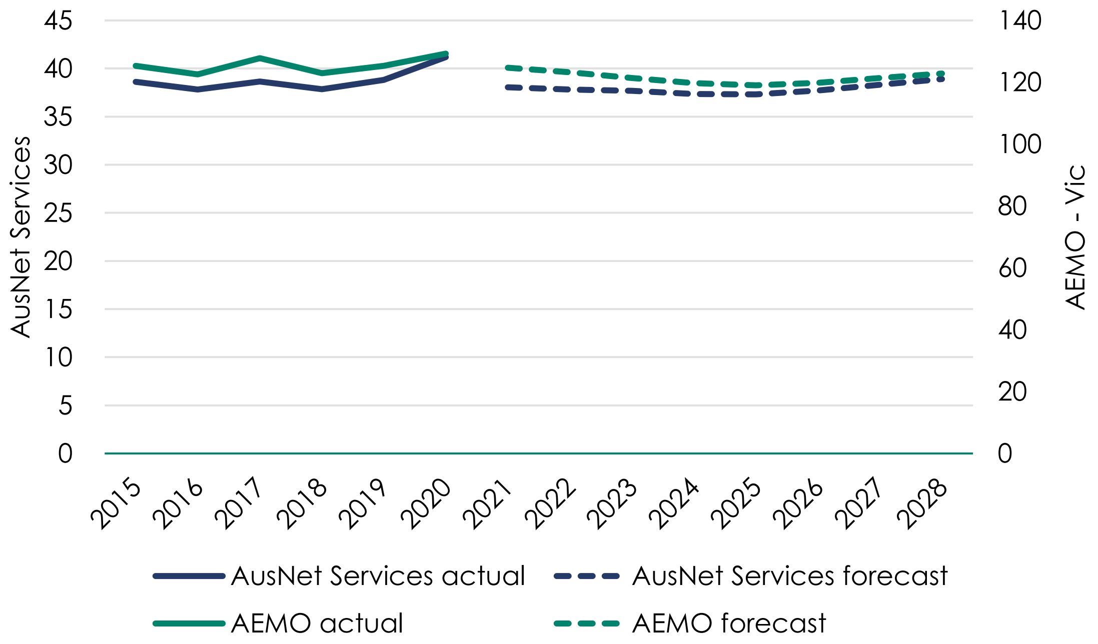
Source: CIE

4.6. Forecast uncertainty in gas networks

The forecasts presented in this chapter have been developed in an environment where there is unprecedented uncertainty for the future of gas networks (see Chapter 3). Given that level of uncertainty our proposal is based on us keeping our options open as to how the future of gas will develop, while still taking steps (where we can) to mitigate the (stranding asset) risks that we face.

A good illustration of the current difficulty in forecasting gas consumption is to show how the forecasts prepared by CIE compare to AEMO's forecasts in its GSOO. At the time, the CIE forecasts were prepared, the 2021 GSOO was the most current version of AEMO's forecasts. The figure below shows how our gas consumption forecasts compared to AEMO's Central (most likely) scenario.

Figure 4.27: Comparison of AusNet Services and AEMO (2021 GSOO) forecasts (PJ)

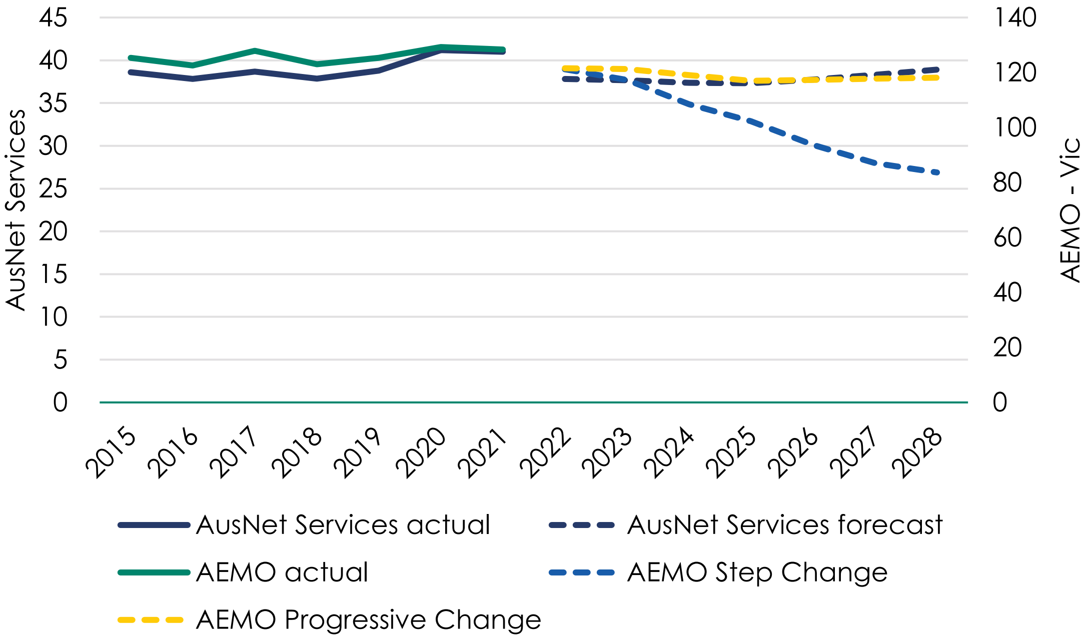


Source: AusNet

It is clear that the two forecasts are closely aligned. Some of this alignment is due to CIE adopting AEMO's assumptions on appliance switching and energy efficiency, however the other elements of the forecasts have been separately forecast by the two organisations.

At the end of March 2022, AEMO published its 2022 GSOO. There is no longer a 'central' scenario and while AEMO notes that all scenarios depict plausible futures, for the purposes of demonstrating the uncertainty of current gas forecasts, we have compared our forecasts to the Step Change and Progressive Change scenarios.

Figure 4.28: Comparison of AusNet Services and AEMO (2022 GSOO) forecasts (PJ)



Source: AusNet

As indicated in the above figure, our forecasts for the forthcoming access arrangement period are consistent with AEMO's 2022 Progressive Change scenario, as they were for the Central scenario in the 2021 GSOO.

However, AEMO's Step Change scenario clearly demonstrates the downside volume risk inherent in our current forecasts. We have chosen to present this scenario because AEMO has noted that stakeholders consider this scenario the 'most likely' scenario.[59] While there no current policy or investment decisions that have been made that would bring about this scenario, the fact it is considered the 'most likely' future pathway is grounds for legitimate concern for volume risk in the forthcoming access arrangement period.

4.7. Supporting documents

The following document provides further information on our demand forecasts:

- ASG – GAAR – Appendix 3 – 2023-28 GAAR Demand, Energy and Customer Forecast – 1 July 2022 – PUBLIC

[59] AEMO, 2022, *Gas Statement of Opportunities*, p. 5.

5. Customer and stakeholder engagement

5.1. Key points

- Over the past 18 months, we have been engaging in conversations with our gas customers and key stakeholders on their current and future needs of our gas network, how we balance the needs of different stakeholders, and how we address key challenges impacting our gas network.
- The influence of our extensive customer and stakeholder process is reflected through-out this proposal and we have made numerous changes as a result – most notably, reducing our discretionary expenditure proposal. These issues are also discussed in Chapter 6 (Capital expenditure) and Chapter 7 (Operating expenditure).
- In an Australian first, our engagement program has been undertaken almost wholly jointly with the other two Victorian gas networks – AGN and MGN.
- There is significant uncertainty around the future of gas in a net zero emissions Victoria and, as such, the future of our gas network. Conversations on the future of gas have dominated our engagement. Stakeholders are clearly pushing for prudent expenditure, which in this context means not spending any more than is necessary until there is more certainty, and we have sought to reflect this in our proposal. That said, there was strong support among customers for not prematurely ruling out the possibility of a hydrogen future.
- Regardless of which decarbonisation pathway for gas eventuates, customers told us that maintaining a safe and affordable network is highly important to them. As are maintaining reliability, providing quality customer service, innovating to better meet key needs and educating customers on key gas matters.
- The entirety of this engagement program has been undertaken during the COVID-19 pandemic, with heavy restrictions on public gatherings in place for much of this period. We designed our engagement program to align with government advice, mandates and participant preferences, utilising online methodologies as required.
- We intend to engage on our proposal for the remainder of 2022. While the topics we will engage on and the format for engagement is yet to be decided, this will be influenced by:
  - Feedback we receive from the AER on our proposal.
  - Further comments from customers and stakeholders.
  - Changes to our operating and policy environment that materially impact our network or our operations.

  We will also continue to engage with our gas customers outside our access arrangement engagement program as part of our business-as-usual research and engagement program.

5.2. Chapter structure

This chapter is structured as follows:

- Section 5.3 provides background on the customer and stakeholder engagement that underpins this proposal.
- Section 5.4 summarises our business-as-usual engagement activities.
- Section 5.5 explains the gas specific customer engagement we have undertaken.
- Section 5.6 sets out what we heard from customers and stakeholders through our engagement program and how we have responded to this feedback in this proposal.
- Section 5.7 provides an overview of our intentions for post-lodgement engagement plans.
- Section 5.8 explains where additional information on the issues raised within this chapter can be found.

5.3. Background

5.3.1. Our engagement program

We have undertaken extensive customer and stakeholder engagement to understand their needs and priorities and develop a proposal that meets them.

We define gas customers as 'the end-users of the gas that we transport'. This includes residential and small business customers as well as commercial and industrial customers. We define stakeholders as any other person, group or organisation that has a stake in our gas business and its operations.

Our engagement includes:

- Our business-as-usual research and engagement program, which gives us an ongoing understanding of our gas customers' and other key stakeholders' needs and priorities, and the environment we operate in.
- An access arrangement specific engagement program, undertaken specifically to inform this proposal, which allows us to go into detail on our network plans and the factors affecting them.

Understanding and addressing the many uncertainties – including from technology, cost, policy, emissions reduction perspectives – and how they impact our proposal has been a key topic of conversation. In addition, many customers and stakeholders have views on a preferred future for gas and balancing these positions along with our own needs and priorities has been a significant challenge.

Undoubtedly, conversations on the uncertain future of gas have dominated our engagement program. Customers and stakeholders appreciate the difficult position we are in – balancing our need to recover the capital we have invested in our gas network (as risk mitigation in the event our networks face early closure) with the need for us to continue meeting our regulatory obligations to connect customers and maintain a safe and reliable network and with meeting customers' needs including affordability, price stability and quality customer experience (all the while not prematurely closing off the option of a renewable gas future should hydrogen become practical for widespread use).

While many stakeholders expressed a view on what the future of gas might be, our residential end-use customers have been clear – they love using gas, and very few are thinking about leaving the gas network. Customers of all sizes have generally low awareness of the decarbonisation pathways for gas (including full electrification of homes and switching to renewable gases or offsets) but accept or support the need to decarbonise. They are thinking about long-term availability of natural gas and have some concerns about the long-term price path for natural gas.

5.3.2. Customer sentiment

For however long our networks are in operation, our customers expect us to continue providing quality services, and not compromising on their two most critical needs – safety and affordability. Customers also told us they want us to:

- Provide reliable gas services.
- Find new and improved ways to deliver services through innovation.
- Provide quality customer service when they need to interact with us.

Our customer service performance is currently strong, with customers giving us an aggregate rating of 8.3 out of 10 for the previous 12 months (at the time of writing) across their interactions in planned and unplanned outages, new connections and claims and complaints (as measured in our monthly customer satisfaction [C-SAT] survey program). Pleasingly, our customers feel we are operating a safe and reliable network, with most unable to recall experiencing a safety incident or outage (planned or unplanned) on our network, and the average customer experiencing an unplanned outage less than once every 50 years.

Our large customers are relatively few but very diverse. They come from industries including oil processing, manufacture of food, textiles, chemicals, plastics, bricks and other materials. Many of our large customers do not have a good understanding of the challenges facing the gas industry and gas networks during the transition to net zero emissions, and do not have plans in place for their business' gas futures. In many cases, our large customers have no or few alternatives to gas, as some of their industrial and chemical processes require specific types of gas.

5.3.3. A joint engagement program

In what we understand to be a first for Australian energy networks, we delivered our engagement program jointly with the other two Victorian gas distribution businesses – AGN and MGN.

Complex and important topics require an extensive engagement process, and working with AGN and MGN on our engagement has had several benefits, including:

- Making it easier for customers and other stakeholders to contribute in a meaningful way through our engagement process. In most cases this has meant attending a single forum, rather than three separate forums on the same topics, and has helped us draw the right people to the room for these conversations.
- Supporting us to do more engagement with our shared resources and reach further and deeper than we might have as individual companies.
- Promoting consistency across networks where an aligned approach makes sense.
- Learning from each other and using the best of each organisations' approaches and ideas to deliver a better engagement program (… and subsequently to design better proposals).

The benefit of this approach has been recognised by our stakeholders and some of the feedback we have received includes:

> "
>
> We welcome the decision of all three networks to undertake combined engagement with one engagement plan. All three networks have a strong commitment to best practice engagement shown in a number of ways, e.g. the combined engagement, co-design of aspects of the engagement plan including key topics for engagement, regular attendance of senior management at engagement sessions, comprehensive slide packs generally distributed ahead of the actual meeting, the building block detail provided early on in the process, the number and structure of various engagement sessions, and the comprehensive Draft Plans.
>
> **Energy Users' Association of Australia**

> "
>
> It actually makes it easier for the community at large to have consistency across the state…understanding that the businesses are all at different stages of development and trying to find that right balance is really difficult.
>
> **Stakeholder, Independent Review forum**

> "
>
> From a process perspective, it's been really good to actually understand and only have one conversation, not have 3 separate conversations as we go through the process with the DBs.
>
> **Stakeholder, Independent Review forum**

5.3.4. Engagement and the COVID-19 pandemic

Most of our engagement program has been undertaken during the COVID-19 pandemic. In response, we designed our engagement program to fit with government advice and mandates, workplace rules and norms, and participant preferences. This meant that most of our engagement has been taking place online, and in a hybrid face-to-face/online format where practical.

Every effort was made to ensure our online engagement channels were accessible for participants, and we have sought continuous feedback on them and on customer and stakeholder appetite for meeting face-to-face throughout.

We found that Victorians had become very used to online meetings during the pandemic. The majority expressed indifference about meeting online rather than face-to-face, and there were a significant number who found online workshops significantly more accessible than face-to-face ones. The fact that we did not have a single customer workshop participant withdraw when the first round was moved from face-to-face to online gave us confidence that holding virtual workshops did not substantially impact the accessibility of the sessions or the diversity of our participants. Technical support was offered to less confident participants across all forums.

5.4. What we heard from our customers

The performance of our network and service levels received very little attention and feedback during our engagement process. Customers and stakeholders indicated they were generally positive about the current levels of safety, reliability and customer service. This has been backed up by our operational data and customer research which demonstrates that outages and safety issues are rare, and when customers do need to engage with us, they are generally satisfied with their experience. There was no desire for an increase in general service levels.

There is, however, widespread acknowledgement that we are in a complex operating environment, and keen interest in how we propose to respond to the uncertainty around gas networks' role in a net zero emissions future. There is widespread frustration at the absence of clear policy from state and federal governments.

We have heard that:

- Stakeholders remain confused about the appropriate response to the divergent possible futures for the network and need a clear narrative around what we see the future being.
- Stakeholders believe we must minimise discretionary expenditure if seeking accelerated depreciation of the network and should test or challenge some of the obligations we are required to meet
- Stakeholders interpret a 'least regrets' action as being an action that would be taken regardless of what future for our network eventuates, and that discussions need to take potential future regrets into account.
- While acknowledging they are regulatory obligations, many stakeholders feel that continuing to connect new customers and deliver high levels of safety and reliability conflict with our proposal for accelerated depreciation, and are inconsistent with how a network with an uncertain future should be investing.
- Most stakeholders want spending on hydrogen readiness to be minimised in this access arrangement period, given the widespread pessimism around the viability of a Hydrogen Hero pathway (see Chapter 3). Many are also uncomfortable with customers paying for hydrogen research given the point above, though some, as a matter of principle, feel they should not pay for innovation under any circumstances, even if there is a known long-term future for the network.
- We need to think about how we may be able to protect customers on our networks (for whom it is difficult to move off gas if/as needed.
- Stakeholders generally understand that we must be given a reasonable opportunity to recover our costs (under the regulatory compact) but question what share of the risk should be worn by customers, government and our business. They are interested in the timing of any cost-recovery from customers – i.e., how much accelerated depreciation we should be able to pursue, and how that is spread across future access arrangement periods. Most stakeholders are open to discussing these questions, though a small number think we should wear all the asset stranding risk, and that they will not support accelerated depreciation under any circumstances.

Stakeholders generally understand the value in keeping options open (and not closing our network off to the possibility of carrying hydrogen in the future, or shutting it down before it reaches end of life if full electrification of the network is the eventual pathway). However, some felt quite strongly that we need to pick a single scenario for our network's future and commit fully to preparing for that. There is broad sentiment though, that the four scenarios developed by the Future of Gas Expert Panel (see Chapter 3) are not equally likely, and that we should put more effort into preparing for some (those that predict widespread electrification of gas) than others (those that predict an optimistic future for hydrogen in residential and commercial settings).

The table below details the specific feedback we received on our draft proposal for public consultation during the first half of 2022. This account of the feedback received was prepared by AusNet and validated by members of our Victorian Gas Networks Stakeholder Roundtable (VGNSR) and Retailer Reference Group (RRG) in May 2022. The table also includes how we responded to this feedback – that is, where the feedback has resulted in a change to our proposal.

Table 5.1 – Stakeholder and customer feedback and how we have responded to it.

Key aspect of our proposal	What we heard	How we've responded
Demand forecasts	Broad feedback that the demand forecasts we have used may be too optimistic, in light of the recently-released 2022 GSOO step change scenario (though consistent with the progressive change scenario), speculation around policies that might be included in the Roadmap, and anecdotal evidence around rising anti-gas sentiment among gas customers and the community more broadly.	We have not changed our deman forecasts, given: • We are still seeing strong connections to our network • We are not seeing any evidence of growing disconnections, and • Our forecasts are consistent wit those in AEMO's 2022 GSOO. We note that a change to demand forecasts would impact prices and our proposed connections capex and we have presented on these sensitivities. We have acknowledged that our demand forecasts will be revised and engaged on post-lodgement i new information that justifies changes – including policy position – arise.
Accelerated depreciation	Stakeholders and customers have differing views on who should wear asset stranding risk – AusNet, government, customers or a combination of these. There has been rising pessimism around our networks' future throughout the engagement process, with stakeholders citing anticipated government policies, geopolitical factors and global markets, and anecdotal changes in community sentiment as the reasons for this. We have heard requests to continue discussing accelerated depreciation during post-lodgement engagement, including: • Exactly how much capital we should be able to recover from customers and what share of the risk is worn by our business and government/s, and whether this changes under different policy settings. • When the best time to undertake accelerated depreciation is – whether it should be started early or delayed, and how costs should be spread over time. • How we have landed on the amount of accelerated depreciation proposed, and justification of why this is the 'right' amount. Stakeholders are also anticipating upcoming Victorian Government policy announcements on gas and are expecting further engagement on accelerated depreciation in light of those announcements. Customers and stakeholders are interested in the long-term price path for energy (gas included). All see valu	We have increased our accelerated depreciation proposa from $130 million to $150 million. Thi is the result of updated modeling analysis and our view that we are ir a higher risk environment as broadl asserted or agreed by many stakeholders. Our modelling is available in Appendices 18-25. It shows that this level of accelerated depreciation i prudent and efficient given current levels of uncertainty. Our accelerated depreciation proposal balances immediate and long-term affordability for our customers with addressing the risks facing our investors. We also consider the price impact in the next access arrangement period is acceptable given the risks it can mitigate for our network and future customers.

	in maintaining affordability and price stability, and many think this is of critical importance. The usefulness of accelerated depreciation as a tool to help control long-term prices appears to be understood, though there was a request that we look further into the time value of money – i.e., smoother long-term prices vs price cuts now – and that we consider sharing any NPV benefits of earlier and greater accelerated depreciation with customers. There was also a concern raised that accelerated depreciation of the sunk investment might lead to a point where the building block model doesn't generate enough cashflow for us to continue operating.	
Mains replacement	Stakeholders and customers accepted that our mains replacement program has a key role to play in maintaining network safety and reliability, which are two of their key needs. They also recognise that safety and reliability are regulated by Energy Safe Victoria (ESV) and that we have limited flexibility to underperform on these. Consistent with strong feedback that we should minimise discretionary capex spend during this access arrangement period, stakeholders asked us to look further at: • The balance between affordability and reliability (and safety) and what, if any, flexibility we have outside ESV requirements to defer safety and reliability expenditure to future regulatory periods. • Capex solutions (e.g., proactively replacing pipes) vs opex solutions (e.g., repairing pipes when there an immediate safety or reliability issue), and whether it would be prudent to swap some proposed capex for opex solutions in the upcoming access arrangement period. Most stakeholders have clearly told us that preparing our network to carry hydrogen should not be used as a justification for mains replacement. They would like to see the program driven wholly by safety and/or reliability commitments.	We have not proposed any changes to our mains replacement program relative to the draft proposal as: • We need to maintain a safe and reliable network, and the mains replacement program is the key program we use to achieve this. We didn't find any justification to delay expenditure to future periods. • We believe it is too early start moving from capex (cheaper in medium- and long-term) to opex (cheaper only when close to decommissioning) solutions for maintaining network integrity. • It doesn't include any discretionary expenditure and is fully-justified under our ESV safety cases. • No part of the program is justified on the basis of hydrogen readiness Chapter 6 of this proposal contains detailed analysis demonstrating that the mains replacement program is needed for safety and reliability purposes and is least cost over the lifecycle.
Customer connections	In the draft proposal, we proposed $194 million to facilitate new customer connections to our network. The drivers of this cost are the capex cost of new connections and forecast connection demand. While we have a legal requirement to continue connecting customers, some stakeholders expressed dissatisfaction with this arrangement. We have also heard stakeholders' requests to consider whether we have the option or even a moral	We have not changed our connections volumes forecast from the draft proposal because: • We are proposing to continue connecting customers in line with our regulatory obligation and have not included any discretionary capex (so have nothing to cut if we are to meet this legal obligation).

	obligation to deter new customers from connecting to our network, in light of: • The stranding risk that new customers are taking on when they choose to connect to our network (and that many customers are not aware that our network's future and the long-term price path for gas, including our bill component, is uncertain). • How much new customers are adding to the stranding risk liability for existing customers – i.e., whether new customers are a help or hindrance to existing customers' cost recovery burden. As a result, stakeholders have requested we provide stronger evidence on the answer to this question. We have also been asked to revisit our capital contributions model amidst stakeholder concern that: • Our forecasts of connection lives are too optimistic • Our forecasts of new connection numbers are too optimistic. • Our forecast consumption is too optimistic, as it may not be correct to assume newly-connected customers will consume the same amount of gas c current customers.	• We do not have evidence of a change in customer sentiment to justify changing our connections forecast, which is consistent with AEMO's 2022 GSOO forecast. We are open to discussing the capital contributions model during post-lodgement engagement, particularly if there are policy announcements, with the caveat that the Gas Distribution Code (GDC) prescribes how these capital contributions are calculated (and would need updating to be more flexible if ou model before our model can change).
Future of gas expenditure	Most stakeholders want spending on hydrogen readiness to be minimised in this access arrangement period given the widespread pessimism around the viability of a *Hydrogen Hero* pathway. We also heard clearly that any expenditure on the future of gas should be deferred unless we can justify: • Why the investments need to be made by us, and why they should be passed on to customers. • Why the investments need to be made in this access arrangement period and cannot be deferred until a pathway for hydrogen is clearer.	Consistent with feedback that we minimise discretionary capex, we have removed the future of gas preparedness capex from our plans. We will instead be seeking a cost pass-through if a legislative requirement for hydrogen blending were to be introduced in the next access arrangement period. We may need to do a more rapid transition close to 2030, if this is proven to be a viable way forward
Productivity	We applied a 0.4% per annum productivity rate in our draft proposal. Stakeholders questioned whether the 0.4% productivity per annum is sufficiently ambitious, and whether AGN' South Australian (SA) network is a good comparison. They asked us to provide more evidence to justify the productivity rate we proposed.	In response to stakeholder question on the ambition of our proposed rate, we engaged an independent consultant (ACIL Allen) to develop productivity forecast for us. Its best estimate is 0.2% per annum, significantly less than the 0.4% per annum we have proposed. We are therefore very confident that our proposed productivity growth of 0.4% per annum is sufficiently ambitious (see section 7.7.3 for more detail). ACIL Allen's report forms part of our proposal, so customers and the AEI will be able to scrutinise this information.

Step change: Bushfire insurance	There was limited feedback received on the bushfire premium increase we proposed in our draft proposal. One stakeholder questioned whether this step change was fair, given higher premiums for bushfire insurance are likely driven by risk on our electricity network (and not the gas network), and the step change might mean gas customers are paying more than their fair share.	In response to feedback, we are removing the bushfire insurance step change and will take the risk on any increased premiums for gas in the forthcoming access arrangement period.
Step change: Gas Network Innovation Scheme (GNIS)	End-use customers are generally enthusiastic supporte of innovation projects. They like the idea of a joint approach across networks and of partnerships with government, academia and other organisations. Man felt that, relative to electricity, which has seen considerable investment, gas has been left behind wit respect innovation expenditure. There was majority support among end-use customers for a joint innovation fund, and customers indicated that in principle, they were comfortable with a small amount of money collected via bills going toward innovation spending. A small number of stakeholders have told us that on principle, they feel customers should not pay for innovation under any circumstances, even if there is a known long-term future for the network. Many stakeholders said they are uncomfortable with customers paying for innovation projects on hydrogen given its uncertain role in our networks' future. We understand stakeholders want us to minimise all discretionary capex spend, and that they would like the GNIS considered in this context.	In response to feedback, we are removing the GNIS from our proposal and will not be seeking ar innovation allowance.
Step change: Priority Service Program (PSP)	Programs to support customers experiencing vulnerability have traditionally been the domain of retailers, who own the financial relationship with customers, and have tended to focus on monetary supports. However, there is growing recognition amon our stakeholders that networks, as the owner of the physical relationship with the customer, have a valuable role to play in ensuring customers who have additional barriers to engaging with their gas service o who are particularly reliant on it receive fit-for-purpose customer service. The concept of a PSP was well-received by customers and other stakeholders, and the proposal in the proposal we will submit to the AER reflects the collaborative efforts of Priority Service Program Advisor Panel, AusNet, AGN and MGN. End-use residential customers were broadly supportive of us establishing a PSP, so long as it did not compromise affordability. Feedback on the PSP included: • A strong preference from social service organisations for a consistent program across the state.	A PSP will be included in our proposal, with some updates. We plan on introducing the following initiatives at no extra cost additional training for front line staf additional 24-hour translation for any service that we offer over the phone, and additional advice on efficient usage of gas. That is, these will be introduced even if the AER rejects the PSP. Based on strong feedback on the need for consistency, we have fully aligned our PSP inclusions with AGN & MGN's program. Program inclusions have been developed with community organisations' input. Costs have been revised down to reflect new information. We will also continue working with stakeholders and customers on the detailed design and

	• Some sentiment that we should assume the whole cost of the program / roll it into BAU. • A need to continue conversations about design and implementation in the lead-up to the program being established if it is approved by the AER. • That we should fund all overheads for the program • Concern that the funds were allocated and the program was costed prior to designing the program. One stakeholder raised concern that introducing the PSP would see us 'expanding operations' during uncertainty (inference that we should be winding down). Other stakeholders considered that such a program became more important to protect vulnerable customers during the transition. Stakeholders and customers alike suggested many considerations for us in the detailed design and implementation of the PSP, including the need to partner with retailers and others to deliver it, use appropriate terminology, measure and report on the program's impact, ensure governance arrangements are appropriate, attract program participants, and make sure the support is going only to those who need it.	implementation of the program (outside this process).
(1) Step change: Meter data trial **(2) Step change: Transmission pipeline inline inspections** **(3) Step change: New state tax & levies**	Stakeholders gave feedback that these three step changes were very small. They questioned whether proposing them as step changes was justified, and whether they should be rolled into the base spend. There was very limited discussion or feedback on the detail of these step changes.	In response to feedback, we are removing these three step changes absorbing their costs and taking on the associated cost risk.
ICT expenditure	We heard strong feedback from stakeholders to minimise discretionary ICT spend, consistent with broader feedback on our investments. Stakeholders did not have a particularly strong understanding of our proposed ICT programs and we received limited detailed feedback on ICT-related aspects of our proposal. Stakeholders told us that they find it hard to engage meaningfully on this topic and acknowledged that the business does need ICT to operate, but stressed they want us to spend conservatively, and do not feel we need state-of-the-art ICT systems improvements.	We have reassessed our ICT expenditure. We have proposed a $6 million cut to our ICT opex proposal (from $18 million in our draft proposal down to $12 million). We are not proposing any changes to our ICT capex proposal but have reduced capitalised overhead costs. ICT expenditure is necessarily lumpy in nature and several key systems need to be replaced in the next

	We were asked to ensure that our proposed IT program did not include costs that had already been approved in our electricity distribution or transmission price resets	access arrangement period. Where replacement is needed, we are proposing like-for-like replacement (and not replacement with state-of the-art systems). We recognise that ICT expenditure difficult to meaningfully engage on Our ICT proposal will be examined by the AER, which is well-placed to assess the prudency and efficiency of our ask.

Source: AusNet

5.5. Business-as-usual engagement

Over recent years, we have made a conscious effort to systematically integrate customers and stakeholders into the development of our strategies, plans and how we deliver our services. This is to strengthen our understanding by engaging directly with those impacted by our decisions and services, or their representatives, outside of regulatory review processes.

Undertaking engagement as part of our business-as-usual operations also means we are not starting from scratch when designing engagement programs for our regulatory proposals. Rather, we seek to continuously gather feedback and adapt to ensure we improve on what and how we deliver for our customers.

5.5.1. Summary and description of activities

Activities we undertake as part of our business-as-usual customer engagement, which complement our gas-specific engagement, are summarised in the table below.

Table 5.2: Business-as-usual activities

Activity	Description
Customer Consultative Committee (CCC)	Our CCC provides an ongoing forum where gas and electricity customer issues are discussed by community and customer representatives, and people with expert knowledge about specific or general customer issues. The CCC meets monthly, and provides us with advice, feedback and input to our decisions and activities which affect gas customers and other stakeholders. It is independently chaired and comprised of 11 external representatives, plus six AusNet representatives, including several senior executives.
Developer Consultative Committee (DCC)	Our DCC meets quarterly and is made up of approximately 16 greenfield property developers (i.e., developers of subdivisions) and several AusNet representatives. This group meets to talk about industry trends and opportunities for improving the developer experience when engaging with us. Greenfield developments account for a considerable proportion of our new connections. While the DCC is primarily electricity-focused, the group engages on issues across both the gas and electricity networks.

Energy Sentiments Survey (Gas and electricity distribution customers)	In our Energy Sentiments research program, we survey 400 residential and business customers twice a year. The survey asks about their attitudes to various aspects of their gas supply, thoughts on AusNet and the industry generally and their energy behaviours and intentions. It is also an opportunity to seek feedback on any initiatives or plans we are thinking of pursuing. The Energy Sentiments survey has also been used to 'sense check' some aspects of our proposal – in particular, validating that key themes emerging from end-customer workshops, such as customers' core needs and intention to maintain their gas connections, are present in the wider population.
Customer Satisfaction Research (C-SAT) (Gas and electricity distribution customers)	We have a robust customer satisfaction research (C-SAT) program. The methodology is monthly telephone calls made to gas (and electricity) distribution customers who have interacted with us in relation to planned or unplanned outages, new connections (including solar and battery for electricity) or a claim or complaint in the month prior. Customer Service Benchmarking Australia (CSBA) delivers the program on our behalf. Insights gained from these customers are a valuable source of data and insight on the end-user customer experience. The C-SAT program provides timely insights and data to help us continually improve our customer service and our longer-term planning.
Meetings with Major Gas Customers	We periodically meet with our large gas customers, to build and maintain trusted relationships and talk about strategic and operational issues in our business and theirs. Some of these meetings were held during our access arrangement engagement program and we spoke to customers about what aspects of their gas services were working well, whether they saw any opportunities for improvement, and the future of gas – what it looks like in their business, and any needs they have of us to help ensure a smooth transition to net-zero emissions.

Source: AusNet

5.6. Proposal-specific engagement

To supplement our business-as-usual engagement, we developed and delivered an engagement program to specifically inform this access arrangement proposal.

Our Gas Access Arrangement 2024-28 engagement program was published in July 2021 following a six-month period of discussions with stakeholders to inform our approach. Our full engagement plan is included as Appendix 4 and is also available on the Gas Matters portal.

Our program was designed to balance broad engagement (speaking to a lot of different people, groups and organisations) and deep engagement (speaking at length and in detail).

Some of our key engagement channels are outlined in the table below.

Table 5.3: Gas specific activities

Activity	Description
Victorian Gas Networks Stakeholder Roundtable (VGNSR)	We established the VGNSR to be involved in the end-to-end development and refinement of our proposal. This Roundtable brings together customer and other stakeholder advocates who represent a wide range of Victorian gas end-users, including customers in vulnerable circumstances, aged customers, culturally and linguistically diverse customers, businesses of all sizes and across all industries, social service organisations, local government, property developers, gas plumbers and appliance manufacturers. The role of the Roundtable and its members was to: • Be involved in the development of our proposal and ensure it is balanced and meets the needs of customers and stakeholders. • Collaborate on the design of our engagement activities so that we deliver best practice, fit for purpose engagement. • Advocate in the interests of the customer groups they represent to make certain our proposal delivers value for all customers. • Challenge our businesses to deliver the best possible outcomes for current and future customers. The Roundtable has met every one to two months since early 2021 and has had oversight of and input across our whole engagement process. The Roundtable is kept informed of all upcoming engagement activities and we extend an open invitation to its members to observe these. We also report back to the Roundtable on the outputs and highlights of all engagement activities. Workshops and deep dive sessions are held with the Roundtable as required and are broadened to include additional sessions and other relevant stakeholders where appropriate. Examples of this include two deep dive sessions that were held in mid-2021 – one on residential and small business customer insights and another on the work of the Future of Gas expert panel – and a series of 4 Deep Dives on key aspects of our proposals held in March 2022. Since late 2021, most VGNSR meetings have been held jointly with the Retailer Reference Group (RRG). The decision was made to combine these as the issues of importance to each group converged during the process and we likely would have had very similar conversations with each group if they were held separately. It also provided a good opportunity for the retailers to hear perspectives of other stakeholders and vice versa. **Members** The VGNSR members are: • Australian Industry Group (Ai Group). • Brotherhood of St Laurence. • Council on the Ageing. • Energy and Water Ombudsman Victoria (EWOV). • Energy Consumers Australia (ECA) – to mid '21. • Energy Users' Association of Australia. • Ethnic Communities' Council of Victoria. • Gas Appliance Manufacturers' Association (GAMAA). • Major Energy Users Australia – to late '22. • Master Plumbers' Association.

- Municipal Association of Victoria.
- Property Council of Australia.
- St Vincent de Paul Society.
- Urban Development Industry of Australia.
- Victorian Council of Social Service.

The following organisations regularly observe the VGNSR meetings:

- Victorian Department of Environment, Land, Water & Planning (DELWP).
- The Australian Energy Regulator (AER) and its Consumer Challenge Panel (CCP).

Meeting Dates & Agendas

Meeting #1 | 3 March 2021

- Overview of our proposed approach to developing our proposal
- Role of the Victorian Gas Networks Stakeholder Roundtable
- About our networks
- Key topics areas for engagement
- Draft Engagement Plan for consultation
- Pipeline services

Meeting #2 | 29 March 2021

- Introduction of agenda and new members
- Final stakeholder engagement plan
- Pipeline and reference services
- Future of gas

Meeting #3 | 27 May 2021

- Business updates
- Reference services proposal
- Stakeholder engagement activities and updates
- Next steps

Meeting #4a | 12 August 2021

- Business updates
- Early Regulatory Modelling
- Future of Gas Expert Panel – Co-design Outcomes
- Stakeholder Engagement update

Meeting #4b | 13 September 2021

- Introduction
- Customer Workshop Findings & Q&A
- Assisting Customers Experiencing Vulnerability – Planning for the Priority Service Program Collaboration Process

Meeting #5 | 20 October 2021

- Business updates
- Better Resets Handbook
- Future of Gas Co-Design Expert Panel

	• Early Expenditure Modelling • Incentive schemes • Stakeholder Engagement update **Meeting #6 |** 17 Nov 2021 • Business updates • Recap of price modelling • Phase 2 customer workshop results • Future of Gas Expert Panel and modelling update • Capital base • Demand • Stakeholder Engagement Update • AER presentation & discussion – Future of Gas Discussion Paper **Meeting #7 |** 16 Dec 2021 (Combined VGNSR/RRG) • Draft Proposal Overviews • Expenditure • Future of Gas • Capital Base • Demand **Meeting #8 |** 2 February 2022 (Combined VGNSR/RRG) • Business Updates • Our Draft Proposals for Early Thoughts and Comments • Deep Dive Methodology – Proposed Topics, Format & Structure • Upcoming Customer Workshops #3 **Meeting #9 |** 13 May 2022 • Stakeholder Feedback: – What We Heard – How We're Responding • Post-Lodgement Engagement Minutes and slide packs from VGNSR meetings can be found on the Gas Matters portal.[60]
Retailer Reference Group (RRG) *	We held regular meetings with the RRG to involve them in the design of our proposal and consulted with them on our reference services proposal and terms and conditions. VGNSR & RRG meetings were combined in later stages due to the same reasons we outlined in the VGNSR section above. Gas retailers play a major role in our customers' experience and are, therefore, critically important stakeholders. We have many touchpoints with retailers during the usual course of our business, but we formally engage via the RRG. Retailers' interests centre on certain parts of our proposals, such as terms and conditions, tariff structures, prices and activities that directly impact them - such as a PSP or changes to metering. RRG meetings are held every one to two months, and we use this time to discuss relevant aspects of our proposals as they are being developed. The RRG's role is to communicate what they need from our network and provide us with feedback

[60] Gas matters website can be acceded via: https://gasmatters.agig.com.au/victorian-engagement-plan (accessed 26/04/2022).

	on our proposal – from their position as both an important stakeholder group and as a critical conduit between networks and end-customers. **Members** The RRG members are: • AGL. • Lumo/Red Energy. • Alinta Energy. • Energy Australia. • Origin Energy. • Simply Energy. • Sumo Energy. • 1st Energy. • Weston Energy. • Tango Energy. **Meeting Dates & Agendas** **Meeting #1** | 11 March 21 • The Joint Engagement Approach & Plan **Meeting #2** | 31 March 21 • Our Final Stakeholder Engagement Plan • Pipeline and Reference Services **Meeting #3** | 28 May 2021 • Business Updates • Final Engagement Plan – Summary of Feedback Received and Changes Made • Reference Services Proposal – Summary of feedback received and how we will respond to it • Future of Gas – Update on Expert Panel Scenario Co-Design • Approach to T&Cs • Potential for a Vulnerable Customer Assistance Program (VCAP) • Close & Next steps **Meeting #4** | 16 August 21 • Policy update • Early price modelling • Future of Gas Expert Panel • Terms & Conditions • Stakeholder Engagement Update **Meeting #5** | 21 October 21 • Business Updates -Future of Gas & Better Resets • Early Expenditure Modelling • Incentive schemes • T&Cs

	Meeting #6 | 18 Nov 21 • Business updates • T&Cs update • Future of Gas Expert Panel and modelling update • Capital base • Demand • SE update & next steps **Combined VGNSR/RRG Meetings** | Meetings #7, #8, #9 & #10 These 4 meetings were combined with the VGNSR. Refer to VGNSR section above for agendas **Meeting #10** | Tuesday 17 May • Stakeholder Feedback: – What We Heard – How We're Responding • Post-Lodgement Engagement • Terms & Conditions • Retailer Credit Support Minutes and slide packs from RRG meetings can be found on the Gas Matters portal.
End-use Customer Workshops	**A series of three iterative customer workshops with five groups across our network to involve end-use residential and small business customers in building our proposal.** As part of our desire for strong engagement with our customers, we delivered three phases of iterative workshops - July 2021, October 2021 and February 2022 - with Victorian residential and small business customers from across our network area. The purpose of these workshops was to gather information and feedback from our customer base on a wide range of topics, and give our customers the opportunity to influence and help shape our future initiatives and investments. These plans include the products and services we will offer, how much is spent on them, and what customers will pay for the distribution component of their gas bill. We wanted to be challenged to improve them. The workshops involved the same group of customers across all three rounds. Over time, it allowed us to discuss topics in more depth as customers' understanding of our gas network and services developed. It also enabled us to demonstrate that we are listening and show the members how their input continues to shape our plans. **The methodology for our customer workshops** • All sessions were held virtually (due to COVID-19 restrictions). • Each round of workshops consisted of five sessions. • The rounds were held with the same groups of representatives from Craigieburn, Warrnambool, Bendigo, and two from Geelong (one of which was a Culturally and Linguistically Diverse (CALD) group). • Workshops had approximately 20 customers in each with a mix of residential and small business participants, representing a wide range of social and demographic areas.

	We engaged two external organisations to help us plan and facilitate the workshops. The first, Diversitat, a community group, partnered with us to hold dedicated sessions for CALD customers in Geelong. The second, Communication Link, an engagement company, assisted us with workshop planning and facilitation, and produced an independently prepared, in-depth report at the conclusion of each round and a final overall report at the conclusion of the third round of workshops. The consultation and engagement activities were delivered in accordance with our engagement principles. That is, they were genuine and committed, integrated and clear, with accurate and timely communication. They were also accessible and inclusive, measurable and transparent. While the workshops were all held online, our customers pleasingly did not have any issues using the core technology (Zoom). Some were less confident using the virtual whiteboard tool (Mural), but their views were captured via scribed facilitated conversation and/or the Zoom chat function. **Workshop Dates & Agendas** **Round 1 Workshops | July '21** In the first round of workshops, we delivered presentations about the gas industry to help our customers better understand our role in bringing gas to homes and businesses. We worked with each group to find out what they value about their gas supply and what areas they feel we should focus on in the future, part of which meant developing an understanding of how their energy use may change over time. We then set out to learn about their needs and preferences so we could focus our time and resources on delivering services that matter and ensuring what we offer remains relevant. We also asked customers for ideas on new and innovative ways we could improve the gas network and the services we offer. As the topics discussed in these workshops were customer led, the feedback from these first sessions informed the discussions during the second round of workshops. **Round 2 Workshops | October '21** The primary objective of the second round of the workshops was to delve deeper into the topics raised during the first round of workshops, which included affordability, safety and reliability, customer service, decarbonisation and the future of gas, innovation and empowering customers through education programs. **Round 3 Workshops | February '22** In February 2022, we held the third and final round of the workshop series. In these sessions, we worked with customers to delve even deeper into the topics discussed in Round 2, and included discussions on the price impacts of the various options proposed in our plans. This included sharing an overview of how we'd incorporated their feedback into our draft plans and going into detail on accelerated depreciation options and the PSP. A detailed report on the customer workshop series completed by our independent facilitator, Communication Link, is attached as Appendix 5. This report and additional materials from our customer workshops can be found on the Gas Matters portal.
Future of Gas Expert Panel *	Empowering a Future of Gas Expert Panel to design a set of plausible scenarios for the future of gas, on which we based our modelling work. Together with AGN and MGN we established an expert panel to consider the Future of Gas. The panel is comprised of nine industry experts (see Chapter 3) and the discussions were facilitated by consulting firm KPMG. The scope of the panel was to: • Co-design four plausible scenarios for the future energy system, including the role of gas.

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- Produce a qualitative description and drivers for each scenario.
- Ensure the designs produced four plausible scenarios rather than predictions or preferences for the future.

This approach was designed to leverage the independence and expertise of each panel member. Their diverse backgrounds ensured the discussions on all scenarios considered the relevant political, economic, social, technological, environmental and legal drivers.

The Expert Panel came together in four workshops of three hours. For each of the 4 scenarios they proposed, the panel explored key industry trends and drivers, developed high-level narratives, outlined assumptions and enablers and graded the potential economic outcomes.

Following the conclusion of the Future of Gas co-design workshops, the members of the Expert Panel were invited to complete a short online survey. They agreed unanimously that the insights they shared were heard and reflected throughout the process, and that the outcomes of the Future of Gas Scenario Development phase were achieved.

Our independent facilitators, KPMG, prepared a report on the Future of Gas Expert Panel's work, which is attached as Appendix 1 and can be found on the Gas Matters portal.

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Major Gas User Forums

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We held a series of three consultative forums in collaboration with the Australian Industry Group (Ai Group), the Energy Users' Association of Australia (EUAA) and Major Energy Users Australia (MEUA). These forums were open to all commercial and industrial gas users in Victoria.

Agendas

25 June 2021

- Welcome and introductions
- Overview: Our Networks & the Victorian Access Arrangement Process
- Discussion: What are the big issues facing major gas users in Victoria?
- Discussion: The future of gas and implications for our large customers
- Q&A with Executives

18 October 2021

- Intro
- Our understanding of your needs
- Our plans
  - Early price modelling
  - Network plans
  - Future of Gas

28 Feb 2022

- Our plans & costs
- Tariffs
- Scenario Modelling (Sensitivity Analysis)
- Options for large customer in a net zero future (Appliances & Hydrogen).

Slide packs from the Major Gas User Forums meetings can be found on the Gas Matters portal.

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PSP Advisory Panel *

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We established a PSP Advisory Panel which collaborated with the three Victorian gas networks on the design of the proposed PSP with social services organisations.

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As our engagement program evolved, it became clear that customers and advocates expect gas networks to provide fit-for-purpose services to all customers, including those who might need extra support or additional care.

We tested the idea of a PSP with residential and small business customers; 81% said they supported the concept and asked us to scope something in more detail.

To develop a program that really delivers on the needs of priority services customers, we established an advisory group. It consists of advocates from organisations that represent a range of customers.

Across three workshops, the PSP Advisory Panel worked to:

- Define the types of customers to be considered priority service customers
- Review existing programs and research undertaken around possible support initiatives.
- Identify gaps in existing programs servicing Victorian customers to avoid duplication.
- Discuss opportunities for cross-sector collaboration.
- Understand where the biggest opportunities for networks to add value are, and prioritising initiatives to be included in a program.

Participating organisations included:

- Council on the Ageing.
- Ethnic Communities' Council of Victoria.
- Victorian Council of Social Service.
- Financial Counselling Vic.
- Safe Steps.
- Consumer Action Law Centre.
- Brotherhood of St Laurence.
- Energy & Water Ombudsman Victoria.
- Uniting Vic.Tas
- St Vincent de Paul.

Agendas

Workshop #1 | 3 November '21

- Introducing AusNet, AGIG and PSP Panel
- Overview of a priority services program
  - Priority services customers
  - The role of gas networks in a Priority Services Program
- Designing a Priority Services Program with you
  - Existing support for Victorians
  - Ideas for existing initiatives & gaps in a Victorian context
- Next steps

Workshop #2 | 2 December '21

- Recap of workshop #1
- Refine program principles
- Prioritise PSP initiatives
- Revisiting customers' needs

	• Overview of Initiatives • Actioning these initiatives • Next steps **Workshop #3 |** 3 February '22 • Recap of where we are so far workshop #2 • Proposed PSP programs – AusNet and AGN/MGN programs • Feedback and discussion on proposals Minutes and slide packs from the PSP Advisory Panel meetings can be found on the Gas Matters portal.
Deep Dive Series *	A series of 4 public **'deep dive' sessions*** – one on the future of gas and one on each of capex and opex – were held, looking at the key aspects of our proposals and to ensure that we fully capture their feedback on our draft plans. The series was well-attended by a variety of stakeholders, primarily but not limited to VGNSR and RRG members. The format and agendas were developed in collaboration with the VGNSR and RRG. **Agendas** **Future of Gas Deep Dive #1 |** 4 March 2022 • The Future of Gas Expert Panel's work • Future of Gas Modelling & Assumptions • Accelerated Depreciation • DELWP Gas Substitution Roadmap Modelling **Capex Deep Dive |** 15 March 2022 – *AusNet Only* • Intro, Background & Overview | Capex in our Draft • Demand and Customer Numbers • Network Growth & Augmentation • Safety & Reliability Programs | Mains Renewal • Hydrogen Expenditure • ICT • Potential Policy Changes **Opex Deep Dive |** 22 March 2022 • AGIG's Opex Forecasts • AusNet's Opex Forecasts • Common New Program 1: Priority Service Program • Common New Program 2: Gas Network Innovation Scheme **Future of Gas Deep Dive #2 |** 31 March 2022 • Modelling • Developments since draft plans • Updated preliminary results • Hydrogen Network Capex • Bringing It Together | A Summary Minutes and slide packs from the four deep dives can be found on the Gas Matters portal.

Property Developer Forums *	We held two meetings with greenfield property developers to inform and consult with them on relevant aspects of our proposal. In collaboration with the Urban Development Institute of Australia (UDIA), we met with greenfield property developers in June 2021 and May 2022 via an online forum. Developers' primary interests are in the future of gas in greenfield developments, and what reaching net-zero emissions by 2050 might look like for gas networks and sharing what we knew was the focus of the first meeting. The second meeting, held in May 2022, was used to update property developers on where we had landed with our proposal, provide an update on our operating environments, and elicit any remaining feedback. **Agendas** **Forum #1** | 17 June 2021 • About Us & the Victorian Gas Access Arrangement Process • Future of Gas | What We're Planning For • Discussion: The future of gas in greenfield/broadacre developments **Forum #2** | 19 May 2022 • Our proposed plans • Update: Key industry developments Slide packs from the Property Developer Forums can be found on the Gas Matters portal.
Gas Plumber Forums *	In June 2021, with the assistance of the Master Plumbers' Association, we held a forum with gas plumbers. Their primary interest is in the future of gas and renewable gas developments and understanding the positions of policy makers. However, we also sought to understand their needs of our network and opportunities for improving our delivery against them. We planned to hold a second forum with this group in early 2022 (referenced in our draft proposal for public consultation), however after following up with gas plumbers it was decided that a second session was not required. We are open to further discussions in the future should this change. **Agendas** **Forum #1** | 16 June 2021 • About us & the Victorian Gas Access Arrangement Process • Future of Gas | What We're Planning For • Open discussion The slide pack from the Gas Plumber forum can be found on the Gas Matters portal.
Gas Network Innovation Scheme (GNIS) Design *	Between September 2020 and October 2021, we participated in sector-wide engagement on innovation in gas networks. This collaborative approach involved AGN, MGN and Jemena Gas Networks (our NSW equivalent), and was undertaken in two key phases, exploring potential design and delivery of gas network innovation schemes in Australia. The aim was to establish how much support there was for a gas network innovation scheme and, assuming it was sufficient, to work with relevant stakeholders to co-design one. The engagement was supported by a GNIS stakeholder reference group specifically set up to provide ongoing advice and feedback on the design and delivery of the GNIS engagement program. This group was assisted by KPMG, who acted as an independent facilitator. KPMG prepared two reports on the GNIS process which be found on the Gas Matters portal. Membership of the reference group included:

	• ATCO. • Evoenergy. • AER. • Energy Networks Australia. • Energy Consumers Australia. • APA Group.
Online engagement portal ('Gas Matters') [1]	The Gas Matters portal provides a one-stop-shop for information on our joint engagement program. It displays information on past and upcoming engagement activities and key contacts for each gas network are shared on the portal.[61] We also use the portal to run surveys and collect forms and submissions from any customer or stakeholder interested in our engagement program. The Gas Matters portal also includes links to all the key documents for the Victorian networks' joint engagement program.
Independent Review *	**KPMG was engaged by AusNet and AGIG to facilitate two workshops with our key stakeholders (primarily VGNSR and RRG members).** The purpose of these workshops was to: • Elicit their thoughts on our draft proposals for public consultation and provide us with a written overview of it; and • Collect their feedback on our engagement program, and their experience participating in it and engaging with us in particular. AusNet and AGIG were deliberately absent from these sessions to help ensure that customers and stakeholders felt able to speak openly and honestly. Participants were also offered the opportunity to provide further comments to KPMG out of session. **Agendas** The workshop agendas were arranged by key topics. **Workshop #1** | Joint VGNSR / RRG, 14 April 2022 • Future of Gas • Capex • Demand • Customer and Stakeholder Engagement **Workshop #2a** | VGNSR, Monday 15 May 2022 • How well stakeholders felt we understood and addressed their feedback in the VGNSR session on Friday 13 May. **Workshop #2b** | RRG, Tuesday 24 May 2022 • How well stakeholders felt we understood and addressed their feedback in the RRG session on Tuesday 17 May. Our independent facilitators, KPMG, prepared a report which is attached as Appendix 6.
Surveys *	Throughout our engagement program, we have undertaken a variety of customer and stakeholder surveys to: • Gather feedback on our engagement.

[61] Gas matters website can be acceded via: https://gasmatters.agig.com.au/victorian-engagement-plan (accessed 26/04/2022).

	• Understand stakeholders' interests and views in a more systematic way. • Gather feedback on sensitive subjects that customers or other stakeholders may not be comfortable discussing in front of a group or would prefer to provide anonymously. For example, industrial customers could be hesitant to share their business plans in a public forum. Typically, we conducted these surveys to complement - rather than replace - other engagement activities. Groups who have completed surveys so far include residential and small business customers - during and following workshops, as well as in our business-as-usual research programs - commercial and industrial gas customers, Victorian Gas Networks' Stakeholder Roundtable members, retailers and Priority Service Advisory Panel members. Open invitation feedback forms and surveys were also periodically opened on the Gas Matters portal.
Publication of a Draft Proposal for public consultation and open invitation for submissions	We published a draft GAAR proposal in mid-January 2022 for public consultation. This document was designed to be a customer-friendly version of our proposal, focusing on what the proposal meant for customers. The purpose of publishing the draft proposal was to share an early view with stakeholders and customers, consistent with our 'no surprises' approach, and to enable more focused engagement as we finalised this proposal for submission. We had an open invitation for any interested customer or stakeholder to provide formal feedback (e.g., written submissions sent via mail or email) or informal feedback (e.g., feedback via phone calls, meetings, emails) on our draft proposal for public consultation. This invitation was emailed to all customers and stakeholders who had participated in our engagement activities to date. It was also published prominently on our website's home page, and shared with our over 17,000 Facebook followers and 4,000 Twitter followers. We emphasised that we were open to engaging via whichever channel best suited the stakeholder. While we received limited uptake of this invitation, it was important to us that anyone who wanted to, had the opportunity to provide us feedback.

Source: AusNet

**Joint AusNet / AGN / MGN activity*

5.7. Post-lodgement engagement plans

We are planning to continue engaging throughout the remainder of 2022 as we await the AER's response to this proposal and prepare our revised proposal.

We are anticipating there may be some changes to our operating environment and the context in which this proposal has been developed before the AER's final decision is made in early 2023. Possible changes include interest rates, government policy and positions (including on the Roadmap), or clarity over some other estimated costs in this plan.

The AER will also be reviewing this proposal and will be publishing its draft decision on our proposal, and that there may be some aspects of our proposal that the AER would like us to engage on further.

However, depending on when we receive or become aware of key information, including AER and stakeholder feedback and other material information impacting this proposal, we may have limited opportunity to engage on how we respond to it. We will, however, seek to maximise opportunities to engage with stakeholders on any changes we make during the post-lodgement engagement period.

5.7.1. Potential engagement topics and methods

Our post-lodgement engagement will focus on:

- Changes to our operating environment between now and the end of 2022 that will impact our network.
- Feedback received from the AER in its draft decision.
- Feedback received from customers and other stakeholders on this proposal.

We are still considering the methods for engagement over this period but expect we:

- Will continue meeting with the VGNSR and RRG.
- Will continue our business-as-usual engagement.
- May re-convene other forums as required.

Again, we will endeavour to invite any interested individual, group or organisation to engage with us, and will provide channels for this whenever it is practical to do so.

5.8. Supporting documents

The following documents provide further information on our customer engagement:

- ASG – GAAR – Appendix 1 – KPMG, Future of gas report – October 2021 – PUBLIC
- ASG – GAAR – Appendix 4 – Engagement plan – July 2021 – PUBLIC
- ASG – GAAR – Appendix 5 – Communication Link report – March 2022 – PUBLIC
- ASG – GAAR – Appendix 6 – KPMG Independent Review report – June 2022 – PUBLIC

Additional information, including the minutes and slide packs from other forums and meetings can be found on the Gas Matters portal.[62]

[62] Gas matters website can be acceded via: https://gasmatters.agig.com.au/victorian-engagement-plan (accessed 26/04/2022).

6. Capital expenditure

6.1. Key points

- We are forecasting total gross capital expenditure (capex) of $563.0 million for the forthcoming access arrangement period. This is 0.0% ($0.2 million) above the capex expected to be incurred in the current access arrangement and 1.6% ($9.2 million) below the capex approved in the current access arrangement.
- A key challenge in developing our capex proposal is to meet our obligations to our existing and new customers while minimising the risk of asset stranding. By carefully balancing these issues, we have met this challenge while also continuing to reduce our average costs (as, on a per customer basis, our real capital base is declining).
- The key projects we are proposing are driven by our compliance obligations and risk mitigation (of operational assets) and include:
  - Completing the existing low-pressure mains renewal program ($81.4 million) as part of the mains replacement program ($134.1 million). This is the final stage of a key safety program which we have progressed over multiple access arrangement periods. Once complete, the volumes of mains replacement will drop significantly in subsequent access arrangement periods.
  - Connecting, on average, 19,460 new residential customers and 145 Tariff V customers per year over the access arrangement period ($237.9 million gross, $204.4 million net).
  - Constructing two new city gates ($6.5 million) to ensure adequate supply pressure in areas where we are expecting customer growth.
  - Replacing several key information and communication technology (ICT) systems ($73.0 million) that are no longer supported and may be subject to cyber or system failure if not replaced. While aspects of our proposal involve some transitioning to the cloud, we expect our full transition to cloud services will occur in future access arrangement periods.

6.2. Chapter structure

The remainder of this chapter is structured as follows:

- Section 6.3 provides an overview of our capex proposal.
- Section 6.4 describes how the capex forecast was developed.
- Section 6.5 discusses our customers' preferences and how we have reflected that feedback in our capex proposal.
- Section 6.6 sets out our capex forecast.
- Section 6.7 presents a summary of our total capex forecast.
- Section 6.8 explains why our forecast expenditure is conforming capex.
- Section 6.9 lists supporting documents relevant to this chapter.

6.3. Overview

As outlined in Chapter 3, we are submitting our capex proposal at a time of material uncertainty about the future direction of the gas network. It is possible that we will transition to a Hydrogen-only network, or we may need to prepare for a significantly reduced (or wholly decommissioned) gas network.

Our capex forecast has, therefore, been prepared on the following basis:

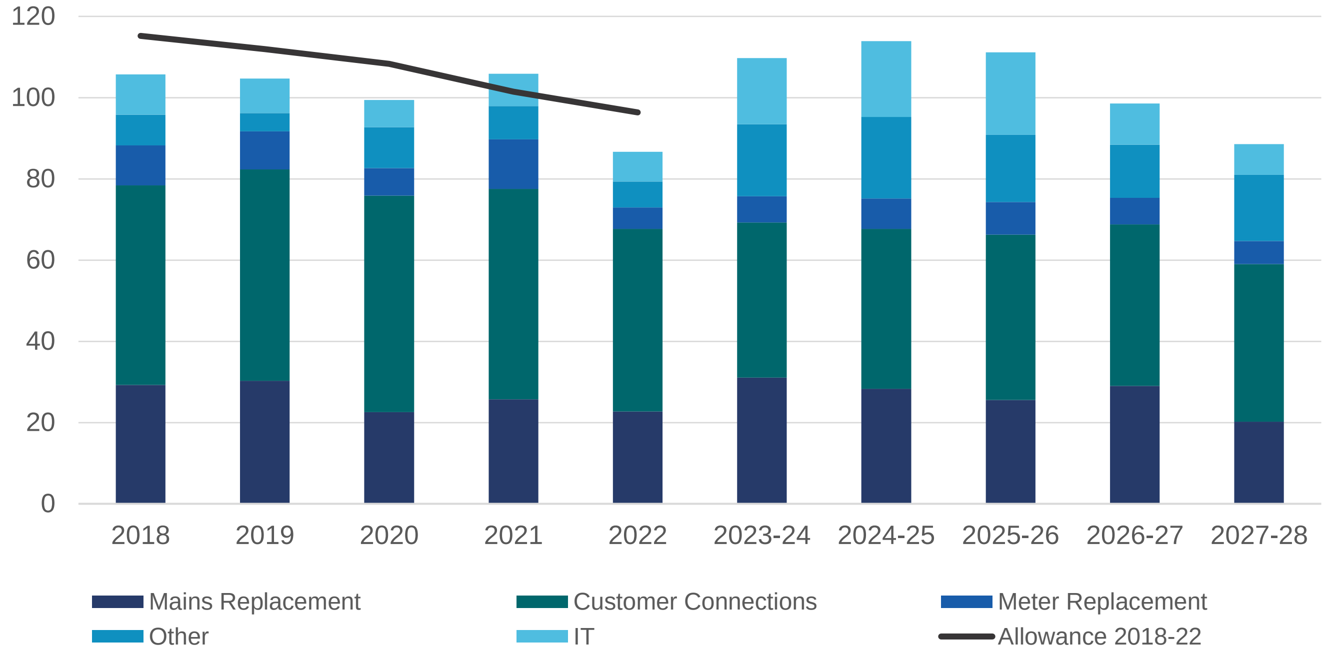
- It is too early to conclude that the gas network will need to be significantly wound down or decommissioned. In any event, we consider that the gas network will continue to operate for the foreseeable future. As such, we must continue to operate it in a safe and reliable manner over the long term.

- There is a customer benefit in keeping the option of a transition to hydrogen open.
- If the Victorian Government's policy announcements provide greater certainty about the future direction of the gas networks, we may need to consider changes to our capital program.

Recognising the uncertainty gas networks are facing, throughout our engagement process (Chapter 5), customers and stakeholders have challenged us on our proposed capex. Having heard those concerns, we have made several changes (relative to the draft proposal[63]), including reductions in some programs.

We are forecasting gross capex of $563.0 million over the forthcoming access arrangement period. This is 0.0% ($0.2 million) above the expected capex in the current access arrangement period and 1.6% ($9.2 million) below the capex approved for the current access arrangement (see the figure below).[64]

Figure 6.1: Net capex, actual and forecast ($m, real 2023)



Source: AusNet

The increase in our proposed capex is largely driven by:

- **New Residential Connections ($202.6 million, gross)**. While our new connections have moderated slightly from record highs in the current access arrangement period, we are expecting significant connection volumes to continue. Importantly, we are required to connect customers to our network if requested to do so and the customer is within the infill area.
- **Mains Renewals ($134.1 million)**, which is required to address safety risks on the network, indicated by increasing Leakage Incident Rates (LIR). We will complete our low pressure mains replacement program in the forthcoming access arrangement period, which fulfils our safety commitments made to ESV as part of the Gas Safety Case.
- **Information and communication technology (ICT) ($73.0 million)**. Major refreshes are required on several critical systems that are now beyond end of life and outside service support. A significant portion of the proposed ICT expenditure is part of corporate-wide initiatives that were approved by the AER in its most recent final decisions for our recent transmission and distribution electricity networks.

Further detailed information on this capex is outlined later in this chapter.

6.4. Capital expenditure program development

In developing our proposed capex program we have considered (among other issues):

[63] The draft proposal is available at: https://www.ausnetservices.com.au/-/media/Files/AusNet/Gas/AusNet_GAAR_2024-28_Draft_Proposal_for_Public_Consultation-_-January_2022.ashx?la=en (accessed 04/05/2022).
[64] Any underspend in total capex in the current access arrangement represents savings that will be passed on to our customers. Customers benefit in the forthcoming and subsequent regulatory periods as there will be through lower capital base growth than would otherwise be the case.

- The condition and performance of our asset base, which is assessed through inspections, maintenance and repairs.
- The alignment of our capex proposal with our vision and objective, along with the national gas objectives as set out in the NGL.
- Our asset management process and drivers.
- The assumptions and inputs underpinning our forecast.
- Interactions with other building blocks.
- The transition that is currently occurring in the energy market; the increasingly complex environment that we are operating within; and the important role gas may have in transitioning to that future.
- Stakeholders' views on key aspects of our proposed capex.
- Compliance with the NGR.

Our proposed capex for the next access arrangement period therefore represents a prudent and efficient level of expenditure that will ensure the continued delivery of safe, reliable and secure gas services to our customers. While we briefly explore each of issues below, further information on our capex forecasting methodology can be found in Appendix 7 – Asset Management Strategy and in the plant strategies that form part of this proposal.

Stakeholders and customers have also played a key role in the development of our forecasts, and this is considered in section 6.5.

6.4.1. Alignment with our vision and objectives

Our purpose is to connect communities with energy and accelerate a sustainable future. Through our strategy we will own and operate a network that will adapt and respond as Victoria moves toward a renewable energy future. Our vision and objectives, which are discussed in more detail in Chapter 2, provide overarching guidance for our capex plans.

6.4.2. Asset management framework

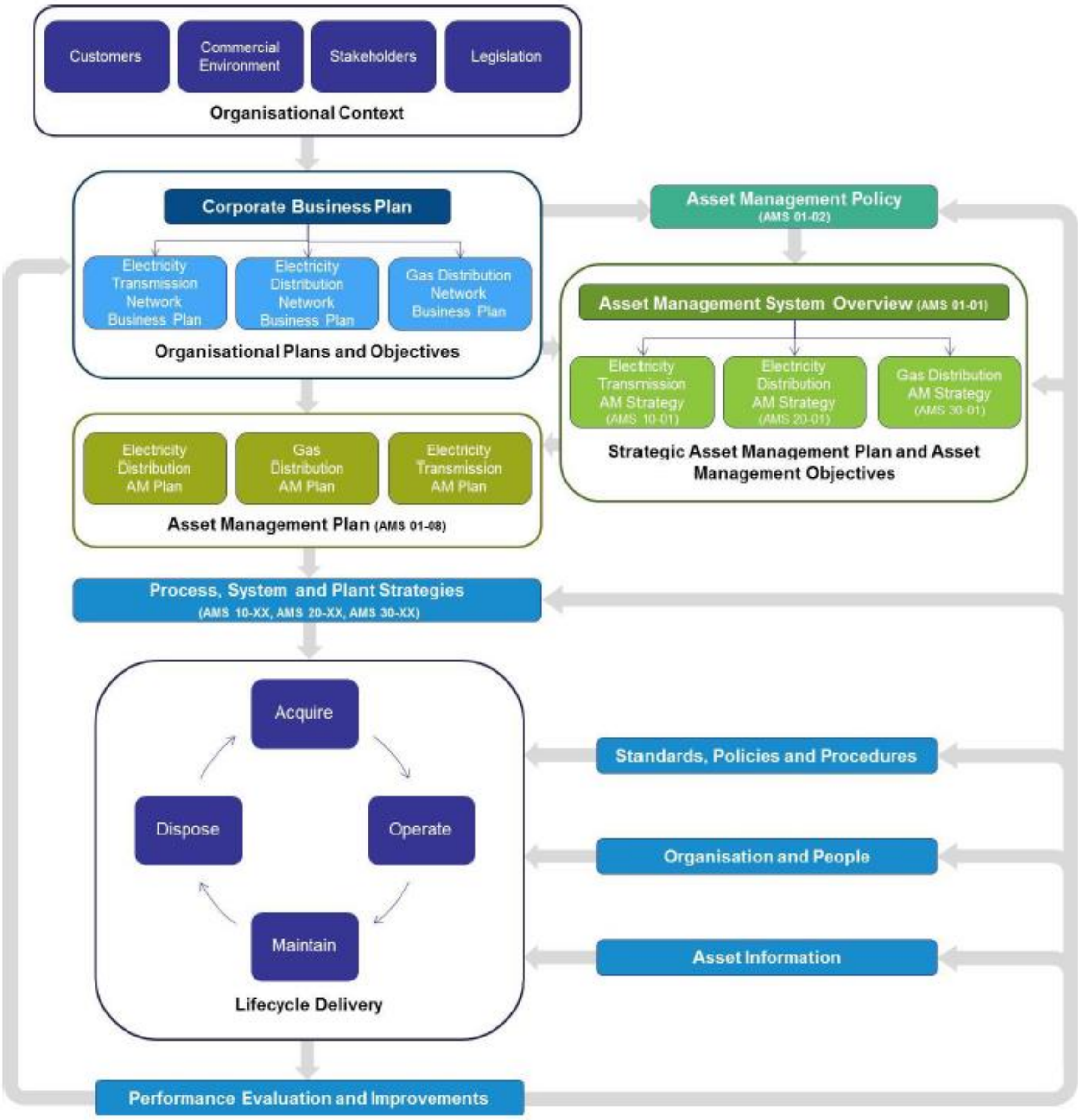
An asset management plan is the approach for managing one or more infrastructure assets that combines technical, financial and other drivers to minimise life cycle costs while delivering a target level of service. Effective asset management is, therefore, critical to delivering efficient capex.

Our asset management approach focusses on delivering optimal distribution network performance at efficient costs. Except where outputs are mandated, the approach requires an explicit cost benefit analysis to be undertaken to assess whether the overall economic value from the proposed capex is positive. In other words, we only proceed with capex if the incremental benefit exceeds the incremental cost. Where the delivery of certain outputs is mandated, we use least cost analysis to ensure that the required output is delivered.

Regardless of the expenditure driver, cost benefit analysis is central to our asset management approach. The various drivers that are brought to bear when undertaking a cost benefit analysis are summarised in the figure below. This approach ensures that all decisions to augment, replace or maintain network assets are justified on economic grounds.

Figure 6.2 below provides an overview of our asset management framework. This framework is centred around the objective to operate the network in the top quartile of efficiency benchmarks with the aim to care for customers and strive to make energy more affordable.

Figure 6.2: Asset management framework



Source: AusNet

6.4.3. Assumptions and inputs

The key inputs and assumptions underpinning our capex forecast include:

- Demand forecasts.
- Project cost estimates and unit rates.
- Asset condition and risk assessments.
- Operational requirements.
- Regulated programs.
- Overheads.
- Cost escalators.

Each of these issues are considered below.[65]

For more detailed information on how specific assets proposed for replacement were selected, please refer to the plant strategies that form part of this proposal.

[65] Our capex forecast is also consistent with the service classification in our Cost Allocation Methodology.

6.4.3.1. Demand forecasts

We plan our network to ensure there is sufficient capacity to meet expected demand over the next access arrangement period. Continued growth in customer numbers is forecast for the next period, which is the key driver of the new customer connections capex forecast. Similarly, augmentation projects are driven by the gas throughput forecast. Details of the demand forecasts that underpin our capex forecast are provided in Chapter 4.

6.4.3.2. Project cost estimates and unit rates

Project cost estimates are prepared as part of a standardised approach to developing, managing and reporting projects and programs of works. Estimates are prepared in accordance with defined project execution procedures and practices and are subject to reviews and a sign-off process. Clear accountabilities are in place to ensure costing standards and controls are applied to any estimate released.

Cost estimates used to determine forecast capex have been prepared on a P50 basis, which is an estimate that has a 50% confidence factor that the estimate will not be exceeded. While our standard estimating procedures generate both P50 and P90 estimates (this is an estimate with a 90% confidence factor that the estimate will not be exceeded), only P50s are used in this proposal.

Unit rates used to develop forecast expenditure are primarily based on the rates incurred in recently completed work. These unit rates reflect the up-to-date efficient costs of delivering similar projects in our network area and are the best forecast of the lowest sustainable cost of delivering the capital programs in the forthcoming access arrangement period. Forecast unit rates are presented in the asset specific plant strategies.

While service delivery is discussed in more detail in Chapter 2, our programs are delivered utilising an efficient combination of competitively tendered and internal resources. We have established pre-qualified panels of design and installation service providers to undertake design and installation works for major projects such as mains replacement and augmentation works. These panels were established by competitive tender and ensure that providers have the necessary skills and resources to undertake the required work in a safe and competent manner.

6.4.3.3. Asset condition and risk assessments

We monitor the condition of our assets through:

- Real-time data acquisition and recording (via SCADA).
- Leakage surveys, leak reports, and UAFG monitoring.
- Asset inspection programs and corrosion surveys.
- Gas quality monitoring, including management of oil-in-gas issues.

These condition monitoring activities are key inputs to our capex plans.

More broadly, we operate a corporate Risk Management Framework that utilises the principles of Australian Standard AS/NZ 4360:2004 and AS/NZ ISO 31000 Risk management – Principles and Guidelines, 2009.

As part of AusNet's Gas Safety Case, a Formal Safety Assessment (FSA) is also carried out every five years and reviewed annually in accordance with *the Gas Safety Act* 1997 (Vic) and the Gas Safety (Safety Case) Regulations 2008 to assess risks associated with our gas distribution network.

6.4.3.4. Operational requirements

While the primary purpose of the gas network is to deliver gas to customers, some assets have additional operational requirements such as measurement, signalling or changing the flow of gas. If an asset loses this additional functionality, we may not be able to detect an issue or respond to an issue appropriately, which means we will be exposed to greater risk.

6.4.3.5. Regulated programs

The requirements of the Gas Distribution System Code of Practice[66] dictate some of the testing and replacement activities included in this proposal. The code of practice nominates field lives of some asset classes. At the

[66] The Gas Distribution System Code was converted to a Code of Practice, effective 1 March 2022 and is now known as the Gas Distribution Code of Practice.

conclusion of an asset's field life, we are obligated to replace the asset. The code of practice also allows for batch testing of some assets which may lead to an extension to the asset fleet's field life.

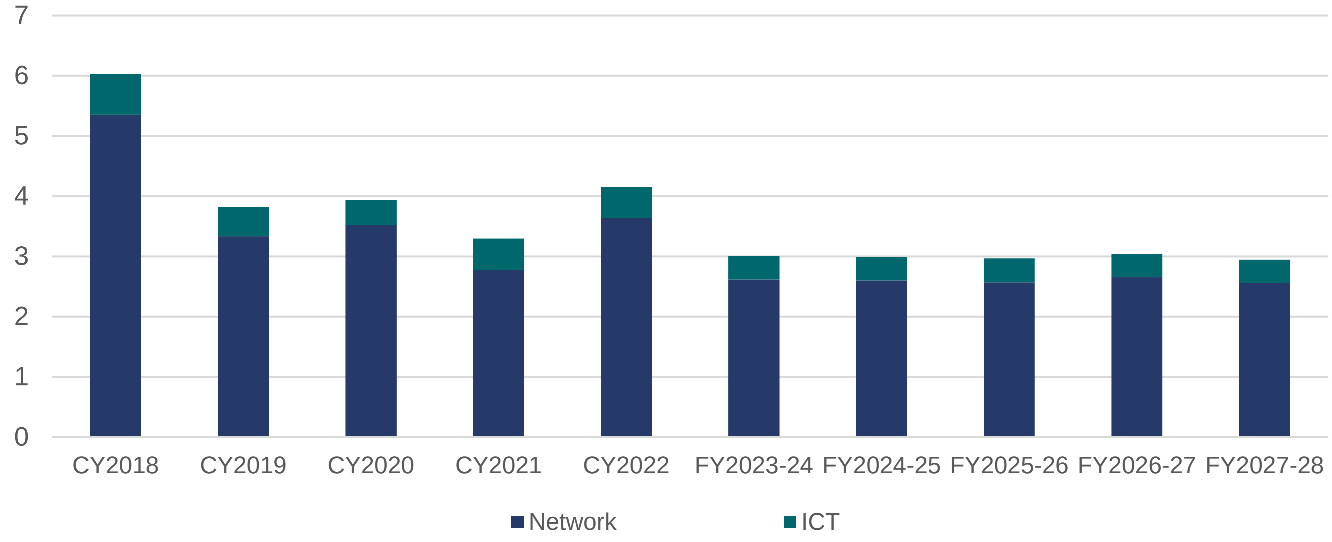
6.4.3.6. Overheads

We have forecast capitalised overhead amounts for network and ICT capex based on the average overheads that we incurred over 2018-21. These amounts have been converted into network and IT overhead rates using the forecasts of network and IT capex, which have then been applied to the respective direct capex forecasts.

Overheads applied to capex forecasts will vary from period to period and in the forthcoming access arrangement period we are expecting overheads to be lower relative to the current period. This is because:

- We have proposed to expense corporate overheads (detailed in Chapter 7).
- Our overheads have reduced during the last regulatory period. This is driven by better internal allocations of costs, which leads to a lower overhead pool needing to be a recovered. We would expect this better allocation of cost to continue during the next access arrangement period.

Figure 6.3: Overheads ($m, 2023)



Source: AusNet

6.4.3.7. Cost escalators

The price of inputs (material and labour) impacts the total expenditure that will be required to deliver the capital work program forecast for the next access arrangement period.

As explained in Chapter 7, we are proposing:

- Materials will grow in line with the Consumer Price Index (CPI), resulting in no real cost escalation.
- Labour costs will increase by the average forecast changes in the Victorian Wage Price Index (WPI) for electricity, gas, water and waste services.

This approach is consistent with the approach the AER has adopted in recent decisions.

6.4.4. Inter-relationships with other building blocks

Our capex forecast is intrinsically linked to the other aspects of our proposal. Any adjustments to any other aspect of our proposal may, therefore, require alterations to our capex forecast. For more information on these building blocks please refer to:

- Chapter 7 for information on our opex forecast.
- Chapter 14 for information on our proposed incentive schemes.
- Chapter 10 for information on our rate of return.

6.5. Customer engagement and feedback

In January 2022, we published our draft proposal and sought feedback on all aspects of it, including our capex proposal. We also ran a deep dive workshop on our capex proposal, including on mains replacement, augmentation and ICT forecasts, and two deep dives on the future of gas.

Participants included customer advocates, retailers and other stakeholders. Representatives from the AER and its Consumer Challenge Panel attended as observers.

Our deep dive workshops were very productive and allowed us to listen to stakeholders' views, address questions and share information, including the options we had considered in developing our proposal.

The feedback we received on capex (from responses to our draft proposal and through our deep dive workshops), and how we have responded to that feedback is summarised in the table below. More detailed information on the process we undertook to engage with our customers and how the feedback received has shaped this proposal is, however, available in Chapter 5.

Table 6.1: Feedback on the capex contained in the draft proposal

Key aspect of our proposal	What we heard	How we've responded
Mains replacement	Stakeholders and customers accepted that our mains replacement program has a key role to play in maintaining network safety and reliability. They also recognised that safety and reliability are regulated by the ESV and that we have limited flexibility to underperform on these. However, we received strong feedback that we should minimise discretionary capex spend and that we should reconsider if we could (1) reduce any expenditure outside of ESV requirements; and (2) replace capex with an opex solution. Most stakeholders also told us that preparing our network to carry hydrogen should not be used as a justification for mains replacement. They would like to see the program driven wholly by safety and/or reliability commitments.	We have reconsidered our mains replacement proposal and have left it unchanged as: • We need to maintain a safe and reliable network, and the mains replacement program is the key program we use to achieve this. We didn't find any justification to delay expenditure to future regulatory periods. • We believe it is too early start moving from capex (cheaper in medium- and long-term) to opex (cheaper only when close to decommissioning) solutions for network maintenance. • It doesn't include any discretionary expenditure and is fully-justified under our ESV safety cases. We have, however, reduced the overheads applied to this program, which has resulted in a reduction in the expected cost of this program. More information on our mains proposal is available in section 6.6.2.
Customer connections	While we have a legal requirement to continue connecting customers, some stakeholders expressed dissatisfaction with this arrangement. We have also heard stakeholders' requests for us to consider whether we have the option or an obligation to deter new customers from connecting to our network. We have also been asked to revisit our capital contributions model amidst stakeholder concern that:	We have not changed our connections volumes forecast from the draft proposal as: • We are proposing to continue connecting customers in line with our regulatory obligation and have not included any discretionary capex in this (so have nothing to cut if we are to meet this legal obligation). • We do not have evidence to justify changing our connections forecast, which is consistent with AEMO's 2022 GSOO forecast.

	• Our forecasts of connection lives are too optimistic. • Our forecasts of new connection numbers are too optimistic. • Our forecast consumption is too optimistic, as it may not be correct to assume newly-connected customers will consume the same amount of gas as current customers.	We are open to discussing the capital contributions model during post-lodgement engagement, with the caveat that the GDC prescribes how these capital contributions are calculated (and would need updating to be more flexible before our model can change). More information on our connections capex is available in section 6.6.8.[67]
Future of gas expenditure	Most stakeholders want spending on hydrogen readiness to be minimised in this access arrangement period in the context of widespread pessimism around the viability of a Hydrogen Hero pathway. We also heard clearly that any expenditure on the future of gas should be deferred unless we can justify: • Why the investments need to be made by us, and why they should be passed on to customers. • Why the investments need to be made in this access arrangement period and cannot be deferred until a pathway for hydrogen is clearer.	We have removed the future of gas preparedness capex from our proposal. We will instead seek a cost pass-through if a legislative requirement for hydrogen blending is introduced in the next access arrangement period. We may need to do a more rapid transition close to 2030, if this is proven to be a viable way forward.
ICT	We heard strong feedback from stakeholders to minimise discretionary IT spend, consistent with broader feedback on our capital investments. Stakeholders told us that they find it hard to engage meaningfully on this topic and acknowledged that we need IT to operate, but stressed they want us to spend conservatively, and do not feel we need state-of-the-art IT systems. We were asked to ensure that our proposed IT program did not include items that had already been approved in our electricity distribution or transmission price resets.	We have carefully reassessed our ICT proposal and have left it unchanged. ICT expenditure is necessarily lumpy in nature and several key systems need to be replaced in the next access arrangement period. Our proposal is appropriate and confirm that we are not proposing state-of-the-art systems that enable new functionality – we are proposing like-for-like replacements. We recognise that ICT can be a challenging issue to engage on and note that the AER will assess the prudency and efficiency of our proposal. More information on our ICT proposal is available in section 6.6.10.

Source: AusNet

[67] Relative the draft proposal our connections capex is slightly higher. However, this reflects a correction to our modelling rather than a change in our volumes forecast.

6.6. Capital expenditure forecast

6.6.1. Overview

We are forecasting total gross capex of $563.0 million for the forthcoming access arrangement period, which equates to net expenditure of $521.9 million after customer contributions. Table 6.2 below, provides annual and total capex forecasts by expenditure category.

Table 6.2: Overview of our proposed capex by driver ($m, real 2023)

Capex by driver	CY2018	CY2019	CY2020	CY2021	CY2022	Jan-Jun 2023	FY2024	FY2025	FY2026	FY2027	FY2028	CY2018-22	FY2024-28
Mains replacement	29.2	30.3	22.6	25.7	22.7	22.6	31.1	28.3	25.6	29.0	20.2	**130.5**	**134.1**
Customer connections*	55.3	61.1	61.7	62.0	56.1	26.4	46.3	47.6	49.0	48.0	46.9	**296.2**	**237.9**
Meter replacement	9.9	9.4	6.8	12.2	5.3	3.1	6.4	7.5	8.1	6.5	5.7	**43.5**	**34.2**
Augmentation	0.4	1.3	4.4	6.0	3.9	2.7	5.0	6.6	3.7	2.2	5.9	**16.2**	**23.3**
SCADA	0.7	0.5	0.4	0.6	1.4	0.2	1.3	1.2	0.3	0.3	0.3	**3.5**	**3.3**
ICT	10.0	8.5	6.7	8.0	7.4	3.7	16.3	18.7	20.3	10.2	7.6	**40.4**	**73.0**
Other*	6.8	2.7	5.3	6.4	11.3	4.9	11.5	12.2	12.6	10.7	10.1	**32.5**	**57.1**
Total Gross capex	**112.4**	**113.7**	**107.8**	**120.9**	**108.0**	**63.5**	**117.8**	**122.2**	**119.5**	**106.8**	**96.7**	**562.8**	**563.0**
Customer contributions	-6.7	-9.0	-8.4	-15.0	-21.3	-5.3	-8.1	-8.2	-8.4	-8.3	-8.1	**-60.4**	**-41.1**
Net capex	**105.8**	**104.7**	**99.4**	**105.9**	**86.7**	**58.2**	**109.7**	**113.9**	**111.2**	**98.5**	**88.5**	**502.4**	**521.9**

Source: AusNet

Note: Some components in both the 'Customer connections' and 'Other' categories lead to up-front payments from customers. These are summated into the 'Customer contributions' category in table 6.2.

The sections below provide more information on various expenditure categories.

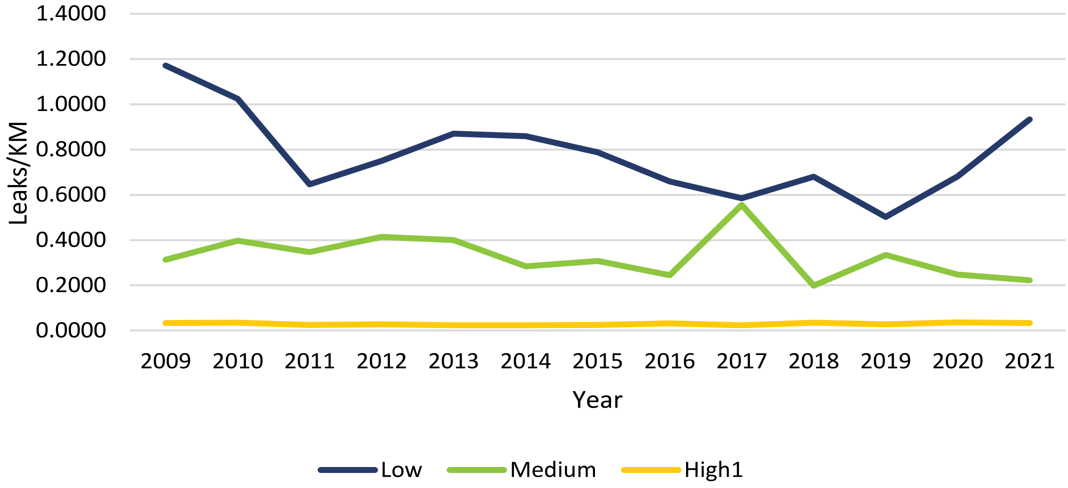
6.6.2. Mains and services

Our proposed mains replacement program has four elements – proactive Low Pressure (LP), Medium Pressure (MP) and High Pressure (HP) programs and reactive ad hoc mains replacements. Our forecast capex for mains replacement is $134.1 million for the forthcoming access arrangement period. This is an increase of $3.6 million or 2.8% compared to the current period. The mains replacement program has increased due to higher unit rates, and increased volumes of MP and HP mains replacement where fleets of materials are identified as being the highest risk cohorts and have unacceptable levels of performance.

Our proposed mains replacement program provides valued service to our customers through improved reliability, reduced leakage (which will reduce ad hoc operational costs and our reactive mains replacement program) and the capacity to transport hydrogen. In other words, it is a key activity in addressing safety risks on the network and fulfilling our obligations under the Gas Safety Case, while also planning for the future.

Under the Gas Safety Act 1998, we are required to submit a safety case to the safety regulator (ESV), outlining the risks on our networks and the activities we intend to conduct to manage those risks. One of the key activities discussed in the safety case is the mains replacement program, particularly, the LP mains replacement program.

Figure 6.4: Mains leakage incident rate by pressure classification



Source: AusNet, AMS 30-52 Main and Services

6.6.2.1. Low pressure program

The LP network operates between 1-7 kPa. The operating pressures of the LP network are limited by pressure restrictions due to the material types (cast iron and un-protected steel) in the network. Due to the low operating pressure and leakage points in the network, the LP network can suffer from blockages caused by water and scale. This is a common cause of outages for our customers on the LP network (most of whom are in rural areas).

Prior to the start of our replacement program (2003), the LP network experienced relatively high levels of leakage. Gas leaks can lead to serious injuries or fatalities as well as property damage. However, with successive rounds of investment we have been able to reduce the risks presented by LP mains. It has been through the combination of the LP mains replacement program and the subsequent reduction in the size of the LP network that has resulted in an 83% reduction in total number of leaks per annum from 1690 leaks in 2009 to only 287 leaks in 2020.

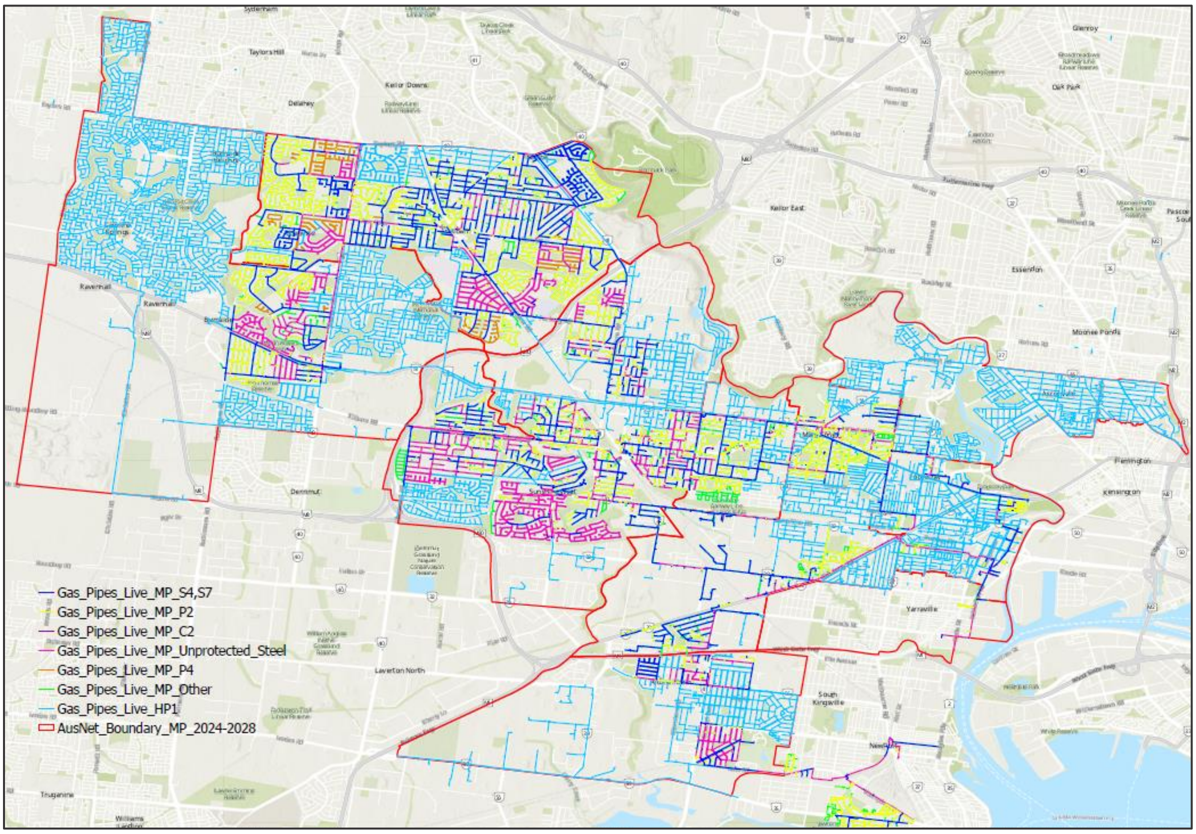
By the end of 2021, only 361 kms of LP mains remained on our gas network. The continuation of the LP replacement program through the 2024-28 regulatory period will remove all remaining LP mains from the network and replace it with HP mains. This will complete the program which has run over multiple access arrangement periods.

The proposed LP mains replacement program will also allow us to decommission 39 district regulators. This will save on routine inspection and maintenance that these regulators would otherwise require (and will also lower network risk). Importantly, no additional capex or opex will be required for district regulators in future access arrangement periods.

6.6.2.2. Medium pressure program

Our proposed medium pressure replacement program involves replacing 94.5 km of medium pressure mains over the forthcoming access arrangement period. These are mains that operate between 15 kPa – 140 kPa, have a total length of 615 km and are largely located in built up urban areas (see figure below).

Figure 6.5: MP network within the Melbourne metropolitan region



Source: AusNet, AMS 30-52 Main and Services

To identify which parts of the gas network are appropriate to replace, we begin by splitting the network into various cohorts by material and pressure and then calculate a relative risk weighting for each. The cohorts with the highest weightings are the ones carrying the highest risks and would, therefore, be prioritised for replacement.

The two main components of risk are probability of failure and consequence. To calculate a relative risk weighting, the leakage incident rate (LIR) for each cohort is used as a proxy for probability of failure. The LIR represents the number of leaks per km a cohort experiences in a year. Hence, the higher the number of leaks in a year, the higher the rate per km and hence the higher the probability of failure of those assets. As a proxy for consequence, a gas flow ratio is used as this reflects the fact that higher pressures will lead to increased volumes of gas escaping during a failure. Since the risk weightings are relative, LP cohorts were assigned a ratio of 1 and MP and HP cohorts were assigned values reflecting the relative amount of gas flow.

The LIR and gas flow ratios were then multiplied together to produce the risk weighting for each cohort. The results of the most relevant cohorts are presented in the table below.

Table 6.3: Risk weightings

Pressure Tier	Material	Length (km)	Ave Annual LIR (leaks / km)	Gas Flow Ratio	Risk Weighting
High Pressure	PE	6001	0.17	11.95	2.03
	PE (First Generation P2)	2753	0.36	11.95	4.30
Medium Pressure	Steel Protected	198	0.64	4.01	2.57
	Steel Unprotected	211	0.9	4.01	3.61
	PE	24	0.34	4.01	1.36
	Class 200 PE (P4)	29	1.56	4.01	6.26
Low Pressure	Steel Unprotected	16	2.57	1.00	2.57
	Cast Iron	179	1.91	1.00	1.91
	PVC	266	1.3	1.00	1.30
	PE	7	0.14	1.00	0.14

Source: AusNet, AMS 30-52 Main and Services

The analysis shows that MP Class 200 Polyethylene pipes and MP Unprotected Steel pipes are two of the highest risk cohorts and therefore appropriate to target for replacement. Their risk weightings are higher than all four LP cohorts.

It is important to note that the LIR of the MP network over the past 10 years has ranged from 0.2 to 0.55. The average annual LIR's for the identified MP cohorts are 1.56 and 0.9 respectively, both above the historical MP range. Replacement of these poor performing materials would therefore maintain the MP network's LIR in the same historical range.

Our proposed MP replacement program is shown in table 6.4 below:

Table 6.4: MP replacement program (2024-28)

Material	Length (km)	% of cohort
P4 polyethylene	28.8	100%
Unprotected steel	56.6	27%
Protected steel	8.7	4%
Cast iron	0.5	100%
Total	94.5	15%

Source: AusNet

P4 polyethylene

This cohort of material in the medium pressure network has been identified as the riskiest. In addition to the higher consequences attributable to a MP network, this material has experienced an average LIR of 1.56, almost three times as high as the highest LIR of the whole MP network in the last decade. For this reason, we are proposing to replace the entire 28.8 km of this material on the MP network.

Unprotected steel

This cohort of material has been identified as one of the highest risk cohorts. The material has experienced an average LIR of 0.9, which is more than 50% higher than the highest LIR of the whole MP network in the last decade. We are, therefore, proposing to replace 56.6 km of this material on the MP network, identified in five postcodes with the highest LIRs, ranging from 2.52 to 11.98.

Protected steel

While this cohort has a reasonable LIR of 0.64, 8.7 km of mains in Braybrook have been identified for replacement as the LIR there is 5.87 – this is the highest LIR of all MP Protected Steel networks.

Cast iron

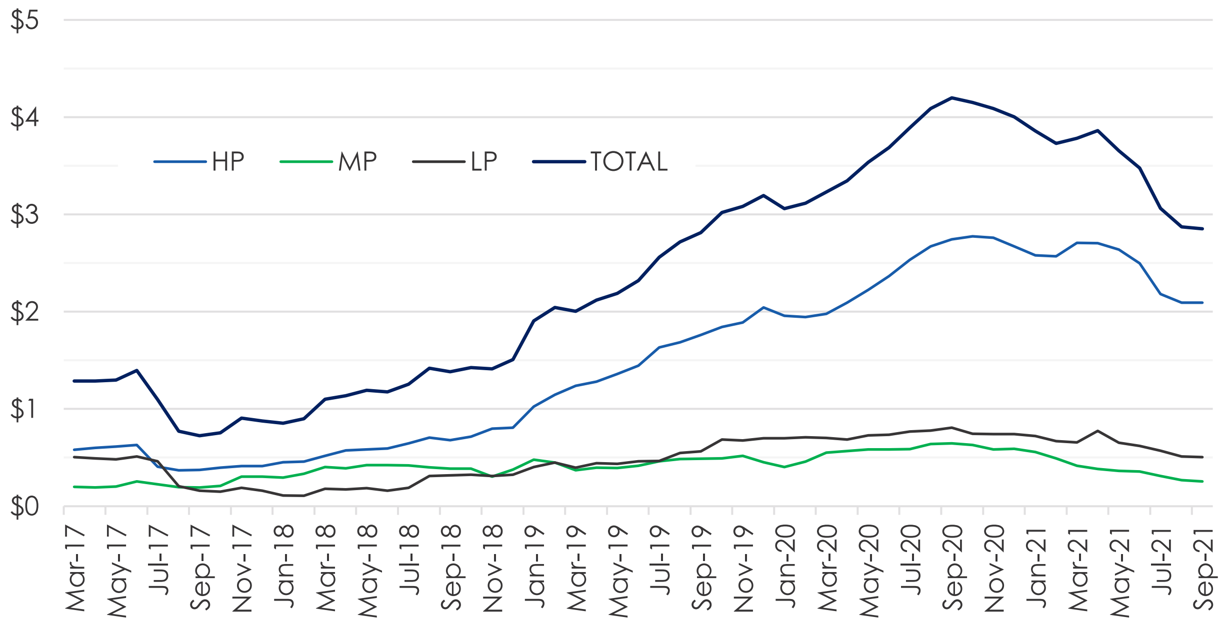
As the cast iron pipes are amongst the oldest assets on the network, it is proposed to replace the remaining 460 m, thereby completely removing this material from the MP network. Over the past 5 years, cast iron has been one of the worst performing materials on the network and due to its age, performance is expected to deteriorate if it is not replaced.

6.6.2.3. High pressure program

The HP network operates between 140kPa – 1050kPa, has a length of over 11,000 km and represents the vast majority of all our mains (approximately 91%). It is also sometimes split into HP (140 kPa – 515 kPa) and HP2 (515 kPa – 1050 kPa).

Given the increase in ad hoc HP replacements we have experienced over recent years we are proposing a proactive HP replacement program to address the increasing risks associated with early generation HP mains. Ad hoc replacement capex incurred in the current access arrangement is depicted in Figure 6.6 below.

Figure 6.6: Ad hoc replacement capex ($m) – 12 month rolling average (March 2017- September 2021)



Source: AusNet, AMS 30-52 Main and Services

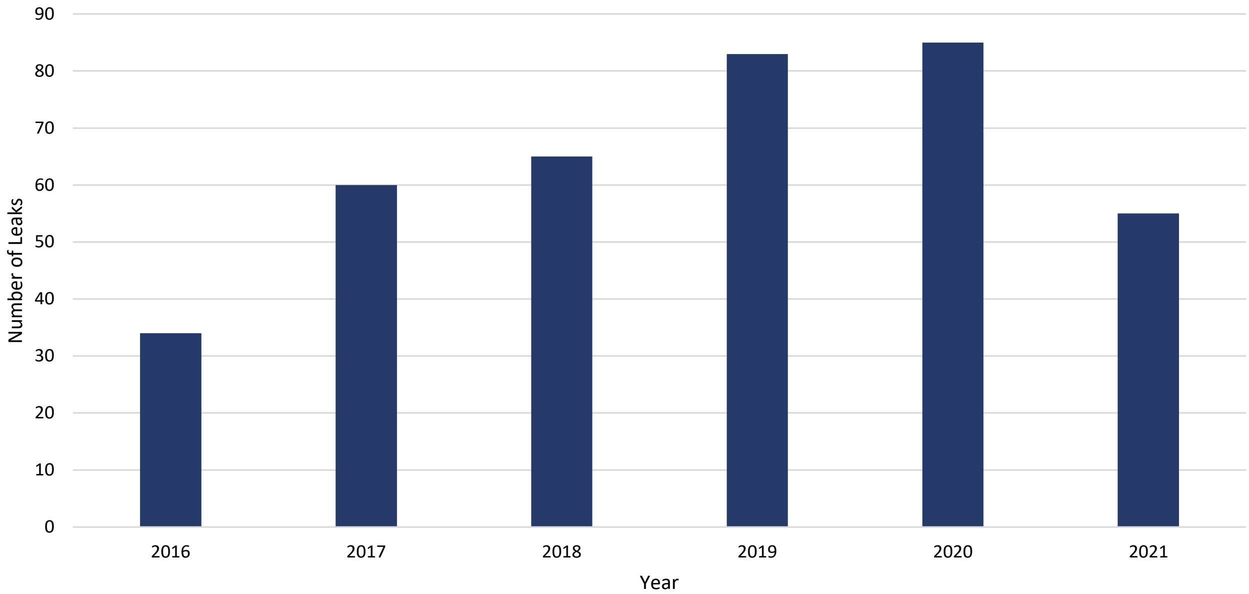
The proactive program we are proposing will be limited to the town of Melton. Our program will target pipes made of the P2 Class 575 material that have identified as the worst performing HP cohort in terms of LIR. It is, therefore, the HP cohort with the highest risk weighting.

Given the poor performance of these pipes, a proactive approach to replacement is appropriate as:

- It will have a lower unit rate (therefore cost) relative to continuing to use an ad hoc replacement approach.
- It reduces risk – given the high pressures and flow rates associated with HP mains, when there is a leak, a larger volume of gas escapes, which corresponds to a greater level of risk.

Our proposed program will focus on 35 km of P2 mains in the Melton HP distribution network given these pipes have shown particularly poor performance. There is currently 130 km of P2 pipeline in Melton. With 85 leaks in 2020, this equates to an LIR of 0.65. This is almost double the LIR of P2 on the whole network (0.36) and quadruple that of all HP polyethylene pipes (0.17) as shown in Table 6.3 above. When the LIR for Melton P2 is multiplied by the HP Gas Flow Ratio of 11.95, the resultant risk weighting is 7.8, higher than any other cohort in Table 6.3. Therefore, this represents one of the most significant safety risks in our network.

Figure 6.7: Annual leakage incidents on the Melton network



Source: AusNet, AMS 30-52 Main and Services

6.6.2.4. Ad hoc mains replacement program

Our proposed ad hoc replacements program ($12.6 million) has been developed using separate assumptions of the expenditure levels for each of the three different pressure levels. In particular, we have assumed that:

- The LP ad hoc expenditure will decrease linearly to zero by the end of the next access arrangement period in line with the progress of the LP mains replacement program.
- The MP ad hoc expenditure will be maintained throughout the period at a direct rate of approximately $0.4 million per year, consistent with recent (5 years) annual expenditure.
- The HP ad hoc expenditure will be reduced from an annual amount of $2.2 million at the start of the period to approximately $1.4 million by the end of the period. This assumes that a pro-active HP replacement program is implemented and targets the worst performing network segments.

6.6.2.5. Mains replacement expenditure summary

In total, we are forecasting expenditure of $134.1 million for mains replacement over the forthcoming access arrangement period. The programs we are proposing are summarised in the table below.

Table 6.5: Mains and services ($2023, $m)

Program	Volume (km)	Capex ($m)
Low pressure mains replacement	273.3	81.4
Medium pressure mains replacement	94.5	29.1
High pressure mains replacement	35.0	11.0
Ad hoc mains replacement		12.6
Total		134.1

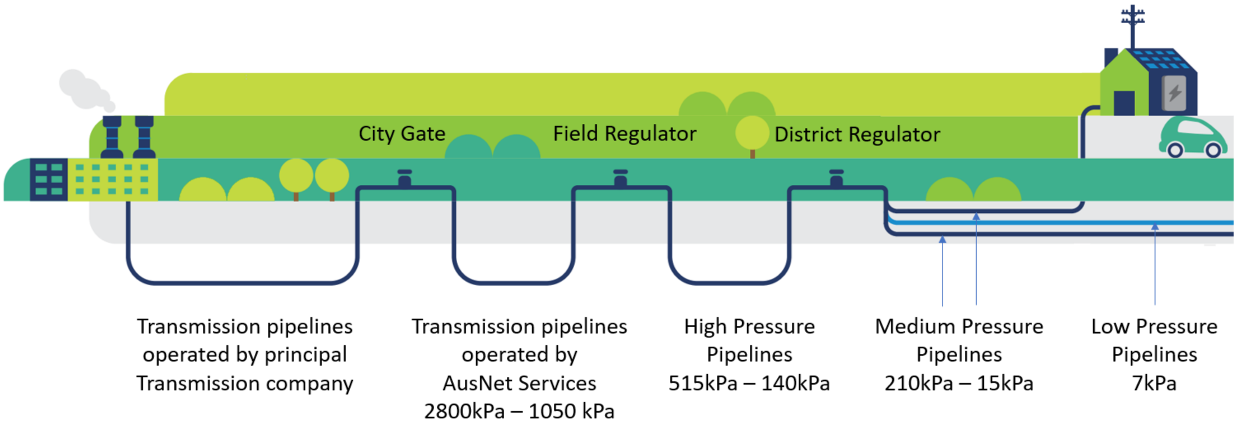
Source: AusNet, AMS 30-52 Main and Services

6.6.3. Network regulators

Our forecast capex for Network Regulators replacement is $10.3 million for the forthcoming access arrangement period. The Network Regulators program has increased due to the identification of a higher number of assets that require replacement.

Network regulators perform a critical function in delivering gas from the principal transmission pipelines and reducing the pressure to safely distribute gas to end users. Each class of regulator facility is determined by the pressure it operates at, as indicated by the figure below.

Figure 6.8: Regulator station asset classes



Source: AusNet, AMS 30-51 Network Regulators.
Note: High pressure pipes in the range 140kPa to 515kPa are designated HP1 while pressures between 515kPa and 1050kPa are referred to as HP2.

A City Gate is a station that receives gas from the Victorian Transmission System pipelines that operate at pressures above 2,800 kPa. The City Gate reduces the pressure below this level and injects the gas into our lower rated transmission pipelines.

We are proposing the replacement of nine City Gate regulators due to ongoing reliability concerns (given the age of the asset) and/or because there is a lack of support by the manufacturer for spare parts. In particular, we are proposing to replace:

- **Six City Gate regulators** due to reliability and supportability issues. Issues include leaking of hydraulic fluid, inability to hold a set pressure and even full component breakdown.
- **Three City Gate regulators** due to operational issues. These three regulators regularly fail to engage the monitor regulator (a backup device) upon a fault. Several solutions have been trialled, however, after consultation with the manufacturer, no solution has been identified. Given the ongoing risk associated with these assets, we are proposing to replace these assets.

We are also proposing to replace:

- **City gate heaters at five sites** – a heater is required at every City Gate site due to the large temperature drop caused by the pressure reduction process. The heaters targeted for replacement are over 35 years old and are approaching end of life. Due to their age, we are experiencing challenges obtaining spare parts for these heaters.
- **Thirteen field regulators** – a field regulator is a station which receives gas from a transmission pipeline network at pressures up to 2,800 kPa and then reduces the pressure below this level and injects it into our distribution network. Of the 13 field regulators we are proposing to replace, nine are over 45 years old and are approaching end of useful life while four need to be replaced due to high fault incidents.
- **Actuators at 26 sites** – actuators are widely used within the gas reticulations to control the valve operation. We are proposing a replacement program to replace the AUDCO P1700 and P480 series actuators as they are over 40 years old and are past their useful operational life. If soft sealing rings are not replaced during specified routine maintenance, there is a risk that the slam shut valve will fail to close resulting in a high outlet pressure incident. The local supplier supporting these models has advised that spare parts for these assets are no longer available and so the risk of maloperation will increase.

6.6.3.1. Network regulators expenditure summary

In total, we are proposing capex of $10.3 million for network regulators over the forthcoming access arrangement period. The components of this forecast are outlined in the table below.

Table 6.6: Network regulators ($2023, $m)

Program	Volume	Capex ($m)
City Gate Regulator Replacement	9	2.8
City Gate Heater Replacement	5	3.3
Field Regulator Replacement	13	3.0
Actuator Replacement	26 sites	0.8
Ad Hoc Replacement		0.5
Total		10.3

Source: AusNet, AMS 30-51 Network Regulators

More detailed information on our network regulators plans is available in our AMS 30-51 Network Regulators document, which forms part of this proposal.

6.6.4. Consumer regulators

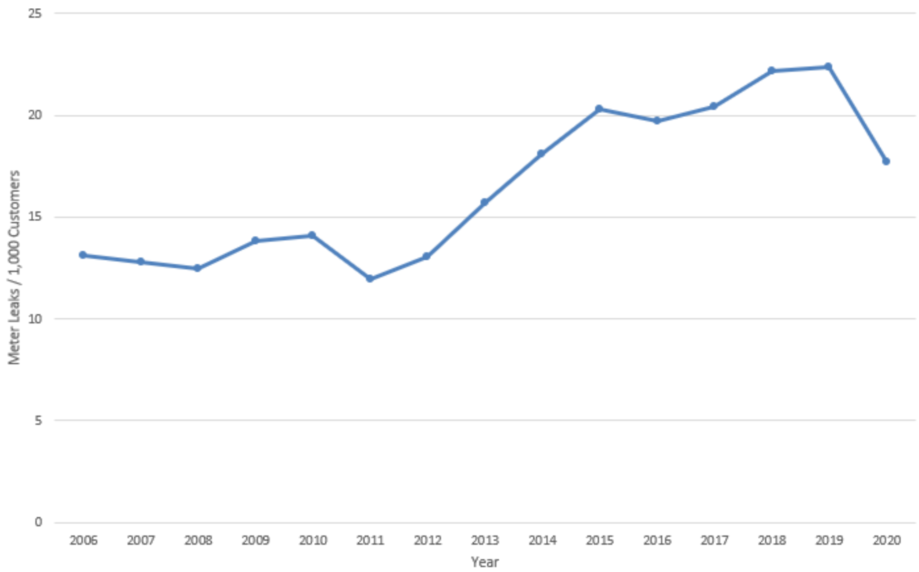
A consumer regulator is a regulator that reduces the gas pressure from the distribution network pressure to a pressure acceptable for entry into a domestic or Industrial & Commercial (I&C) customer's premise.

Our forecast capex for consumer regulators is $14.1 million for the forthcoming access arrangement period. Our proposed consumer regulators program has increased due to the introduction of a proactive replacement program.

Consumer regulator failure can result in gas leaks. These leaks, when combined with an ignition source, can cause significant damage to a customer's property. Even if there is no gas escape, a failure in the closed position results in a customer outage, while failure in the open position may result in higher pressures on the customer's appliances than they are rated to handle.

Historically, due to low volumes of faults, consumer regulators have not been subject to proactive maintenance or replacement and have been replaced when identified as faulty. However, increased leaks on these regulators has led to an increase in risk over time. In 2019 the leakage rate of domestic meters was almost double what it was in 2011. Consumer regulators account for approximately 80%-90% of domestic meter leaks.

Figure 6.9 Meter leaks per 1000 customers (includes consumer regulator)

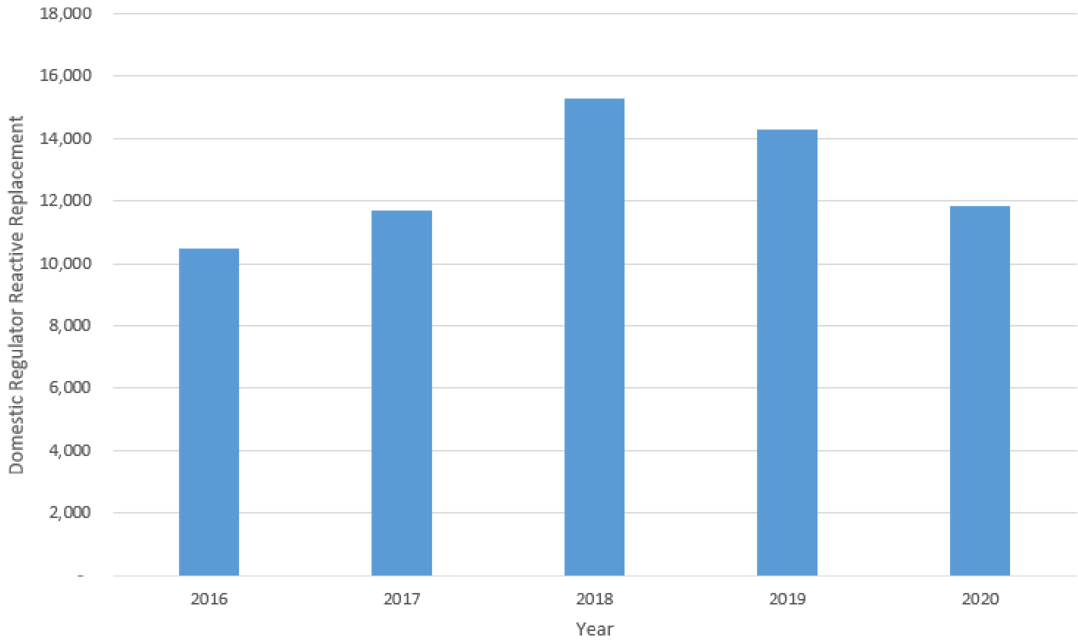


Source: AusNet, AMS 30-53 Consumer Regulators

We are, therefore, proposing to begin pro-active replacement of consumer regulators. Consumer regulators are to be replaced at the same time as a customer's meter is replaced. By conducting both programs concurrently (and not relying on a reactive replacement program) we estimate that installation costs associated with consumer regulator replacement will reduce by 64%.

Based on the customer meter replacement program, 70,000 consumer regulators would be replaced over the 5 year access arrangement period if done in conjunction with meter replacements. This equates to approximately 10% of the consumer regulator based. Therefore, the number of ad-hoc reactive replacements would reduce by approximately 10%. Based on 2016-2020 replacement data (see below), it is estimated that an average of 10,780 units, being 10% less than the 5 year average, will need to be replaced annually as part of reactive works.

Figure 6.10 Consumer regulators replaced due to faults



Source: AusNet, AMS 30-53 Consumer Regulators

6.6.4.1. Consumer regulators expenditure summary

In total, we are proposing capex of $14.1 million for consumer regulators during the forthcoming access arrangement period. A breakdown of the forecast replacement volume and associated expenditure is presented in the table below.

Table 6.7: Consumer regulators ($2023, $m)

Program	Volume	Capex ($m)
Proactive Consumer Regulator replacement	70,370	4.3
Miscellaneous Actuator replacement	10	0.3
Reactive Consumer Regulator replacement	53,935	8.4
Other Faults	250	1.1
Total		14.1

Source: AusNet, AMS 30-53 Consumer Regulators

More information on consumer regulators is available in our AMS 30-53 Consumer Regulators document, which forms part of this proposal.

6.6.5. Customer metering

Our forecast capex for customer metering replacement is $34.2 million over the access arrangement period. This is a decrease of $9.3 million or 21.4% from the current period and reflects the age profile of our meters and the meter families that are due for replacement.

Gas meters are used to measure the volume of gas passing through it. The volume of energy that passes through the meter is dependent on both gas pressure and temperature at the time of measurement.

We have a fleet of meters, with residential meters representing 97.5% and I&C meters comprising the remainder. We must maintain these installations, replace meters when their field life has expired, and provide metering information to retailers for billing and market settlement purposes. Accordingly, we undertake a range of annual meter testing and replacement programs to ensure compliance with our regulatory obligations, including the Gas System Distribution Code of Practice.

We are required to undertake In-Service Compliance Testing and a Time Expired Meter Program to fulfil our obligations under the Gas System Distribution Code of Practice. Specifically, each year, a sample of meters will be tested as part of the In-Service Compliance Testing. Depending on the results of the test, their in service life (which begins at 15 years) may be extended (called Field Life Extension). At the end of a meter's service life, taking into account any field life extension, it must be replaced (Time Expired Meter Replacement).

Based on historical performance, a prediction has been made on which families will pass or fail their in service compliance tests. These assumptions have been used to forecast the number of meters to be replaced in each year, taking into account possible field life extensions.

We are proposing to test around 6,000 meters and replace around 134,100 meters that will reach the end of their in-service lives. We estimate approximately 2% of these replacements will be challenging (called 'no access' replacements) where multiple site visits, additional interactions with customers, extra equipment or out of hours appointments may be required. Where this is necessary, a relatively higher unit rate will be required ($158.64 per meter compared to $137.52 per meter).

Similarly, we expect to replace approximately 3,000 I&C meters on a similar time-based regime.

Despite proactive replacement of consumer meters, we are still expecting thousands of meter faults to be experienced on the network each year. We are therefore proposing a reactive replacement program of approximately 4,100 sites per year to cover domestic, I&C meters and dataloggers (electronic devices which collect gas usage information from a physical gas meter).

A trial of 1,000 digital meters will be conducted to investigate remote and real time reading capabilities. The benefits of digital metering include improvements to the accuracy of data collection, billing accuracy, safety of meter readers, responsiveness to connections and disconnections, and network planning.

6.6.5.1. Customer metering expenditure summary

In total, we are forecasting expenditure of $34.2 million for customer metering over the forthcoming access arrangement period. The various programs that make up our forecast are outlined below.

Table 6.8: Customer metering ($2023, $m)

Program	Volume	Capex
In service compliance testing	6,008	1.2
Time expired meter program	134,100	19.6
'No Access' non-compliant	2,682	0.5
Trial digital meters	1,000	0.5
Domestic meter faults	20,000	4.1
I&C time expired meters	2,921	5.0
I&C turbine meter replacements	19	0.5
Reactive I&C meter replacements	301	1.6
Full meter rebuild	1	0.3
Old inline datalogger or flow corrector sites	90	0.6
Reactive datalogger or flow corrector sites	41	0.3
Total		34.2

Source: AusNet, AMS 30-54 Meter Management Strategy

Note: Total may not add up due to rounding.

More detailed information on meter replacement is available in our AMS 30-54 Meter Management Strategy document, which forms part of this proposal.

6.6.6. Cathodic protection

Our forecast capex for cathodic protection is $2.1 million over the forthcoming access arrangement period.

We use cathodic protection and associated systems to actively defend against corrosion of buried steel assets in our gas transmission and distribution networks. Cathodic protection is sometimes achieved by the introduction of a sacrificial anode. This anode is a piece of metal which sits in the vicinity of a pipe and will corrode in preference to the pipe. In other words, the anode is sacrificed. The networks feature 196 active cathodic protection units that protect 2,683 km of steel pipeline and mains. By preventing corrosion, cathodic protection (among other factors):

- Maximises the useful life of assets, thereby deferring the need for more expensive replacement programs.
- Mitigates the hazards and risks to the safety of the public, and the risk of property damage associated with gas supply.
- Maintains the integrity and reliability of services.

Cathodic protection capex requirements are primarily driven by the electrical voltage found on pipes. If the electrical voltage for a specific area is found to be below the desired level, the pipes in the area will not be sufficiently protected from corrosion. This indicates that the cathodic protection unit may need to be replaced, or additional units may need to be installed. Cathodic protection systems have a variable useful life that is dependent on factors such as the environment in which they are located, the condition of the main they are shielding, and other environmental factors. As such, the existing systems require routine capital investment to ensure their correct function. Some devices, such as sacrificial anodes, are deliberately perishable and are expected to require periodic replacement.

Additional cathodic protection will also be required to help protect new assets that we are using to expand the network due to continued demand for gas (see Chapter 4), further contributing to our forecast capex.

Site by site assessments are performed to determine where new cathodic protection systems are required, or existing systems need to be replaced.

6.6.6.1. Cathodic protection expenditure summary

In total, we are forecasting expenditure of $2.1 million for cathodic protection over the forthcoming access arrangement period. Our proposal is summarised in the table below.

Table 6.9: Cathodic protection ($2023, $m)

Program	Volume	Capex ($m)
Replacements	54 of various items	0.6
New assets	102 of various items	1.5
Total		2.1

Source: AusNet, AMS 30-56 Corrosion Protection

More detailed information on cathodic protection is available in our AMS 30-56 Corrosion Protection document, which forms part of this proposal.

6.6.7. SCADA

Our forecast capex for Supervisory Control and Data Acquisition (SCADA) is $3.3 million over the forthcoming access arrangement period. This is a decrease of $0.2 million or 5.7% from the current period reflecting the relatively consistent nature of the SCADA capex program.

SCADA assets provide 24 hour visibility and control of the gas network by the Customer Energy Operations Team (CEOT), which operates 365 days a year. For example, pressures can be remotely controlled and variables like temperature, flow and water levels can be monitored remotely from a centralised control room. The SCADA assets, therefore, allow us to respond instantaneously to changes on the gas network to minimise safety risks and ensure the ongoing supply of safe and reliable energy supply.

New and replacement SCADA assets are required to respond to the expanding gas network as well as for spares management where suppliers are no longer supporting obsolete models. Old and deteriorated assets must also be replaced to reduce risk of failures.

6.6.7.1. SCADA expenditure summary

We are forecasting expenditure of $3.3 million for SCADA in the forthcoming access arrangement period. This comprises of various programs as follows:

Table 6.10: SCADA ($2023, $m)

Program	Volume	Capex ($m)
Replacements	313	2.9
New assets	30	0.4

Source: AusNet AMS 30-57 SCADA

More detailed information on our SCADA program is available in our AMS 30-57 SCADA document, which forms part of this proposal.

6.6.8. Customer connections

We are forecasting gross expenditure of $237.9 million ($204.4 million net) for customer connections over the forthcoming access arrangement period. This is a decrease of $58.3 million or 19.7% compared to the current access arrangement period.

As a regulated business, we must, upon request and within specified time periods, connect a customer to the distribution network on fair and reasonable terms. The Gas Distribution System Code of Practice specifies the minimum standards for connection and disconnection of customers to our distribution network.

Customers contribute to the cost of works to connect to the network only where the present value of the increased network revenue, resulting from the new connection, is less than the present value of the additional costs of that connection. This means that most residential connections occur without any customer contribution. Where customer contributions are necessary, we reduce the forecast capex by an amount equal to the total forecast customer contributions. This approach ensures that the capital base (Chapter 8) only increases by the amount of capex that we fund.

Currently, residential connections account for the majority of new customer connections expenditure. We are continuing to forecast growth across our network. Our connections modelling shows an average increase of 20,700 new residential customers and 54 Tariff V customers per year over the upcoming access arrangement period. To calculate our forecast customer connections expenditure, we multiply the new connections forecast by a historical unit rate (for present purposes, based on 2018-2020 data). Similarly, forecast expenditure for I&C customers has been derived by multiplying forecast connection by a unit rate derived from 2020 actuals.

6.6.8.1. Customer connection expenditure summary

We are forecasting gross expenditure of $237.9 million ($204.4 million net) for customer connection over the forthcoming access arrangement period.

Table 6.11: Customer connections ($2023, $m)

Program	Volume	Capex ($m)
Residential connections	103,910	202.6
Commercial and Industrial Tariff V connections	270	26.5
Commercial and Industrial Tariff D connections		8.8
Gross customer connections		237.9
Customer contributions		-33.6
Net customer connections		204.4

Source: AusNet, Capex model

6.6.9. Augmentation

We are forecasting expenditure of $23.3 million to meet growth of our network over the forthcoming access arrangement period. This is an increase of $7.1 million or 43.8% from the current period, largely driven by two new city gates in Werribee and Craigieburn.

Under the Gas Distribution System Code of Practice[68], we are required to maintain minimum pressure in the gas distribution network and ensure it remains above prescribed levels to the extent to which it is within our power. One reason for this obligation is to minimise loss of supply to customers on cold winter days (peak demand). To continue to meet this obligation, we must augment the network.

[68] Clause 2.1(b), Gas Distribution System Code of Practice.

We have identified 11 sites across the network that require augmentation in the next access arrangement period to maintain required gas pressures in developing areas of the network. In some cases, this involves reinforcing existing upstream sections of pipe. This is done by adding additional pipes in parallel to the existing network, thereby allowing higher volumes of gas to flow through that pathway. In other cases, augmentation involves the creation of new routes are created from high pressure supply points through to the areas experiencing poor supply.

They address both existing and expected pressure issues. In some cases, large sections of the network are being back fed from alternative routes to relieve the strain on existing sections of the network.

Table 6.12: Proposed augmentation projects

Site	Pipework	Facilities
Macedon Ranges		Field Regulator Upgrade
Point Cook	1 km of 200mm S11	
Bacchus Marsh	650 m of 125mm P10	
Sunbury	5 km of 180mm P10	
Ballan	165 m of 180mm P10	
Craigieburn	2 km of supply main	1 new City Gate
Tarneit	3.2 km of 180mm P10	
Ballarat	1 km of 300mm Transmission Pipe 900 m of 200nn Distribution Pipe	
Bendigo	360 m of 180mm PE 400 m of 63mm PE	
Geelong Bellarine	3.3 km of 180mm PE	
Werribee	5 km of supply main	1 new City Gate 2 City Gate Upgrades

Source: AusNet, AMS 30-17 Network Capacity Strategy

6.6.9.1. Augmentation expenditure summary

We are forecasting expenditure of $23.3 million to meet growth of our network over the forthcoming access arrangement period. This comprises of various programs as outlined in the table below.

Table 6.13: Growth ($2023, $m)

Program	Volume	Capex ($m)
Pipe reinforcement	25 km	15.5
New facility installation	2	6.5
Facility upgrades	4	1.3
Total		23.3

Source: AusNet, AMS 30-17 Network Capacity Strategy

More detailed information on augmentation is available in our AMS 30-17 Network Capacity Strategy document, which forms part of this proposal.

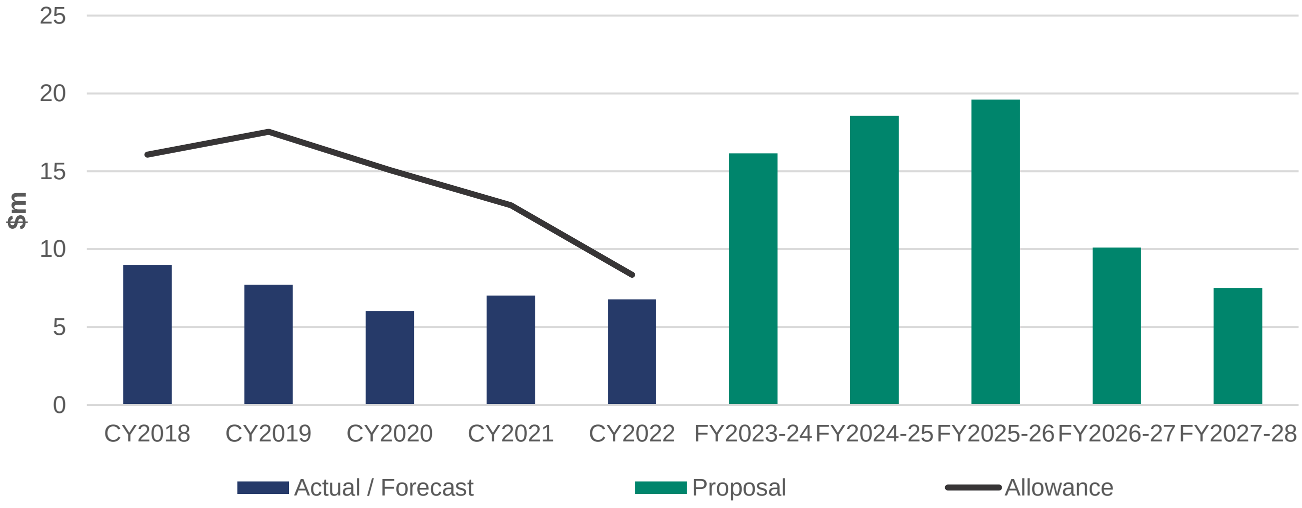
6.6.10. Information and Communication Technology (ICT)

We are proposing expenditure of $73.0 million for ICT expenditure over the next access arrangement period. This is an increase of $32.6 million from the amount of expenditure we expect to incur in the current access arrangement period.

The majority (60%) of our ICT programs are corporate-wide initiatives that were approved by the AER in its final decisions for our electricity distribution network and our transmission network.[69] However, we have also proposed additional expenditure that is specific to our gas business.

The figure below provides a summary of the forecast expenditure in this category compared with the previous access arrangement period. This shows that that ICT expenditure is cyclical, reflecting the timing of major upgrades and the lifecycle replacement of ICT systems. It also confirms that we are entering a period where expenditure is increasing. This is being driven by new cyber security requirements, the more complex ICT environment we are operating in, and the need for lifecycle replacement of systems that are past their useful life and no longer have vendor support.

Figure 6.11: ICT capex



Source: AusNet

Figure 6.11 also shows that we have managed to meet our ICT requirements by spending an amount lower than our allowance. The underspend is largely due to reprioritisation and will benefit our gas customers as the value of the ICT asset base at the start of the access arrangement period will be lower than it otherwise would be the case. This underspend can, therefore, be viewed as a saving to customers.

In developing our ICT proposal, we engaged external technology consultants and internal technology experts familiar with the gas network to assist us to develop a best practice, fit for purpose, IT strategy (see Appendix 9). In preparing our strategy, we had regard to industry trends, regulatory requirements, and our business needs. While we have looked to maintain current service levels and meet new obligations, we have also proposed the use of technology where we expect network and customer benefits can be achieved. Importantly, our ICT strategy maintains the continuation of a cautious approach to technology in a complex and uncertain environment that intends to maintain current service levels and meet new obligations.

6.6.10.1. Key drivers of ICT

The ICT capex forecast is based on the GAAR IT Strategy (Appendix 9) that has been developed for our gas distribution business. This is focused on lifecycle replacement to keep existing systems operating, rather than undertaking significant investment in new capabilities.

Our key drivers for the gas network are:

- **Customer expectations**: based on recent research our customers expect us to 'deliver on the basics', 'keep me posted', 'make it affordable', 'be ready for the future', and 'always (be) safe'.
- **Digital enabled business:** we recognise that digital technology plays an increasing role in gas networks to increase automation, support more evidence-based decisions, and enhance customer outcomes.

[69] See: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ausnet-services-determination-2022%E2%80%9327/final-decision and https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ausnet-services-determination-2021-26/final-decision (accessed 17/05/2022).

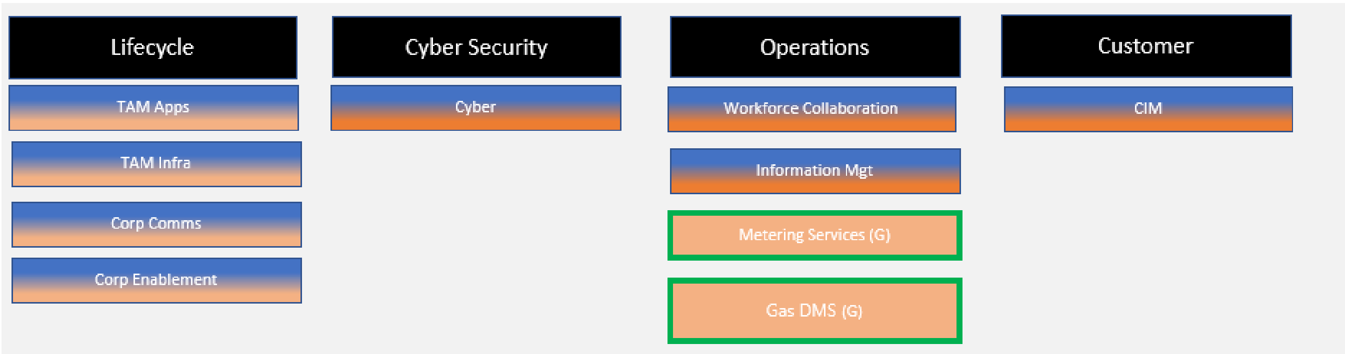
- **Cyber security:** the increased dependence on digital technology requires greater levels of cyber security to mitigate the risk of threats and attacks, and therefore maintain a safe and secure network and working environment, and protect customers' privacy.
- **Business strategy:** we are focused on our core business of continuing to provide the same level of service to our customers, while ensuring that we invest prudently to respond to future industry change.

Investment to replace and maintain our key technology systems and infrastructure are necessary to ensure we maintain our current services and deal with the ongoing complex challenges we face into the next access arrangement period.

6.6.10.2. Programs of work

Our technology programs reflect the minimum requirements necessary to enable us to maintain the services we are currently providing. There are 10 programs of work that address the four workstreams of our Digital portfolio.

Figure 6.12: Technology workstreams



Source: AusNet

Note: The Metering Services and Gas Network Operations programs are specific to Gas while the other programs are shared across our Electricity Distribution and Transmission businesses.

A brief description of each of these workstreams is outlined below:

- **Lifecycle** – Manages risks to the services delivered by core Technology systems by undertaking lifecycle refreshes of our storage, enterprise servers, desktop and laptop fleet, and corporate network and communications control technology.
- **Cyber Security** – Protects the distribution network, and customer and business information and assets, through continued investment in our cyber security capabilities, in line with the requisite compliance, industry standards and benchmarked practices from utilities around the world.
- **Operations** – Enables data and analytics, automation, visualisation, modelling and risk management to continue to efficiently provide reliable gas supply services. Investments in our enterprise systems to maintain safety and meet customer demand for information and communication on our network operations, including extending solutions to the field, and greater integration and collaboration and extending information solutions to the field.
- **Customer** – Manages customer interactions and services.

Our ICT proposal programs are summarised in the table below. Consistent with the AER's assessment guideline, NPV analysis has been conducted for non-recurrent expenditures. Detailed information is contained in the ICT program briefs and the GAAR IT Strategy (Appendix 9) that form part of this proposal.

The costs of the company-wide programs outlined below reflect the allocation to the gas network of expenditure for programs approved by the AER in the EDPR and TRR. However, we have also identified several gas-specific projects that complement the shared projects in some of these programs, and we discuss these in more detail in the section below.

In costing both the company-wide and gas-specific programs we have:

- Considered the views of our customers (see Chapter 5).
- Held discussions with business and technology architects, and (internal) business delivery leads to develop the scope, key objectives, and drivers of our ICT proposal.
- Considered different options to achieve the objectives of each ICT program and analysed the relative costs, benefits and risks of each.
- Undertaken a top-down review and internal challenge to ensure that our ICT proposal represents prudent and efficient expenditure for the next regulatory period.

- Used industry standard labour rates and applied consistent costing methodologies.

Table 6.14: ICT forecast capex ($m, costs)

Program	Categorisation		Description	Total cost	Gas network share of program	Gas network specific cost
	Recurrent	Non-Recurrent				
Technology Asset Management (TAM) - Applications	100%	-	This program ensures the ongoing reliability of critical operations by fixing bugs and performing periodic patching.	$3.0	$3.0	-
TAM - Infrastructure	100%	-	This program maintains IT systems and helps optimise data centre infrastructure assets, including hardware and licenses and enables transitions to the cloud.	$7.6	$7.6	-
Corporate communications	100%	-	This program ensures the lifecycle management of corporate communications including networking devices (i.e., Wi-Fi, routers), internet services provision and data centre interconnectivity.	$5.0	$5.0	
Corporate enablement	70%	30%	This program ensures the ongoing sustainability of core business systems. This includes replacing core business functions such as HR and Payroll systems to meet increasing requirements and enabling an improved partner network across the enterprise. NPV: $1.3 million	$6.3	$4.4	$1.9
Security	45%	55%	This program ensures compliance with regulatory requirements. It protects our assets, information and systems from cyber security threats. NPV: $17 million	$8.7	$8.7	-
Workforce collaboration	70%	30%	This program allows teams to access information regardless of location (such as in the field). It will also facilitate collaboration, through knowledge capture and transfer, and improve the accuracy of planning, budgeting and forecasting. NPV: $0.2 million	$7.1	$7.1	-
Customer information services	-	100%	This program will refresh our customer systems, improving the interactions we have with our customers. It will allow us to meet evolving customer, regulatory and metering data needs.	$3.2	$2.3	$0.9

			NPV: $3.2 million			
Information management	37%	63%	This program allows us to analyse network performance in an increasingly complex environment. Using near real time data we will make better decisions, increase our efficiency and continue to deliver reliability. NPV: $4.3 million	$14.4	$5.4	$9.0
Gas-specific programs						
Metering Services	62%	38%	This program refreshes metering assets to mitigate risks and ensures the ongoing operation of a compliant metering service. NPV: $2.8 million	$3.0	-	$3.0
Gas distribution management system (Gas DMS)	76%	24%	This program refreshes key network management systems and ensures the ongoing operation of the gas distribution systems by reducing operational and safety risks. NPV: $5.6 million	$14.6	-	$14.6
Total				**$73.0**	**$43.5**	**$29.4**

Source: AusNet

Note: Totals may differ due to rounding.

6.6.10.3. Gas-specific projects

As outlined in Table 6.14 (above), we are proposing $29.4 million expenditure for gas-specific ICT capex to replace out-of-date and obsolete systems and applications that are beyond their asset lives and, in some cases, where there is no longer application vendor support.[70] This investment will provide us with a technology stack that will help mitigate the risk of application and systems failure and enable security patching to counter cyber threats.

Outlined below is additional information on the gas specific projects identified above.

Metering services

This $3.0 million project involves investing to meet evolving customer, regulatory and metering data needs. This will benefit vulnerable and life support customers through better engagement and continued compliance of gas life-support customer obligations and billing accuracy. This is explained in more detail in the briefs and GAAR IT Strategy that form part of this proposal.

Gas DMS

This $14.6 million project addresses the risks associated with continuing to use systems that are well beyond their end of life and vendor support. Specifically, we are looking to replace our existing DMS (distribution management system) and OMS (Outage Management System) to enable integration of our geospatial and customer information platforms. This will reduce the risks associated with cyber threats, system failure or errors in our manual processes. For example, investing in a current network operations system will allow us to apply security patches to defend against increased cyber threats, noting that this could not be possible under our current arrangements.

Other projects

This $11.8 million program of work will facilitate better insight into and analysis of data to support investment decisions and the allocation of capital, while not compromising on customer service or network safety. These programs will also benefit vulnerable and life support customers through better engagement and continuing compliance of gas

[70] This $33.0 million captures the gas distribution management system, metering services and additional investments to projects that have previously been considered by the AER as part of the EDPR and the TRR, namely – Information management, Customer information systems and Corporate enablement.

life-support customer obligations and billing accuracy. This is explained in more detail in the briefs and GAAR IT Strategy that form part of this proposal.

6.6.10.4. Transition to cloud

Recognising that the cost, performance, security and availability of externally hosted technology services – both infrastructure and applications – 'in the cloud' has improved substantially over the last five years, we have carefully considered the viability of cloud-based options in preparing our ICT proposal. Specifically, we have considered:

- How we could transition our core systems infrastructure to the cloud.
- The costs and risks of maintaining our current on-premises technology assets relative to a cloud-based option.

Our analysis concluded that we should not retire or replace most of our existing infrastructure and data stores with cloud-based solutions in the short term. Rather, our approach involves taking an orderly transition to cloud. Importantly, when change is required, we consider options, including a move to cloud, to determine if it will deliver the most prudent and effective response. During the forthcoming access arrangement period, where there are benefits for a cloud transition, we have captured the applicable costs in our proposal.

Our transition to cloud has begun to offset some capex relating to technology infrastructure. In these cases, we have captured and reflected that saving in our proposal. However, in most instances the hardware on which these applications operate are used in conjunction with other services. This means that they cannot be decommissioned until a later period. In future access arrangement periods, we expect we will be able to take further advantage of cloud-based services and increasingly move from existing on-premise solutions.

6.6.10.5. Benchmarking and validation

To obtain insight into the key ICT needs, trends and strategic direction of the business, all relevant areas of the business were engaged in preparing our ICT forecasts. We also used external consultants, including Deloitte Consulting, PwC consulting and technology experts, to provide industry benchmarks and budget estimates to validate the efficiency of our proposed technology expenditure.[71] Our internal and external experts have also contributed to the development of our GAAR IT Strategy.

Our approach to ICT gives us assurance that our forecasts are prudent and efficient and are in line with industry best practice.

6.6.10.6. ICT expenditure summary

We are forecasting expenditure of $73.0 million for the forthcoming access arrangement period.

Table 6.15: ICT ($2023, $m)

Program	Capex ($m)
Technology Asset Management - Applications	3.0
Technology Asset Management - Infrastructure	7.6
Corporate Communications	5.0
Corporate Enablement	6.3
Security	8.7
Workforce Collaboration	7.1
Customer Information Services	3.2
Information Management	14.4
Metering Services	3.0
Gas Distribution Management System	14.6
Total	73.0

Source: AusNet

Note: Totals may differ due to rounding.

[71] See, for example, ASG - GAAR - PWC ICT expenditure proposal - 1 July 2022 – PUBLIC.

6.6.11. 'Other' capex

Our forecast 'other' gross capex is $30.6 million ($23.1 million net), which accounts for approximately 5.4% of our capex forecast.

The 'Other capex' category includes all capex that does not fall into the capex driver categorises discussed above (excluding overheads). This includes:

- $16.4 million for major alterations. These are large scale construction projects where a third party, such as the government, request an alteration to a part of our network. There is usually a significant customer contribution amount associated with this category.
- $2.9 million for security fences and CCTV upgrades, which is being driven by new obligations we will become subject to by virtue of recent amendments to the Security of Critical Infrastructure Act 2018 (Cth)[72]. Nine city gate regulator sites have been identified as requiring security fences and an additional four sites require CCTV upgrades. This is a step change from the current access arrangement period.
- $5.9 million for Transmission Line Pigging, which is being driven by aging transmission lines. Pigging is a condition assessment technique where a device is sent though a pipe to monitor pipe thickness and deformities.
- $5.3 million for general capex, which is being driven by the need to ensure buildings and equipment remain fit for purpose.

6.6.11.1. 'Other' expenditure summary

We are forecasting gross expenditure of $30.6 million ($23.1 million net) for the forthcoming access arrangement period.

Table 6.16: Other capex

Program	Capex ($m)
Major alterations	16.4
Security fences and CCTV upgrades	2.9
Transmission line pigging	5.9
General capex	5.3
Gross customer connections	30.6
Customer contributions	-7.5
Net customer connections	23.1

Source: AusNet

Further information on each of these issues can be found in the supporting documents that form part of this submission.

[72] The *Security of Critical Infrastructure Act 2018 (Cth)* was amended in March 2022 to introduce new obligations relating to the security of 'critical infrastructure assets', which includes our gas distribution network. Once these obligations take effect (which we expect will be some time in 2022), we will be required *inter alia* to identify all hazards and minimise or eliminate any material risk of such hazards from occurring. The proposed hazards to be considered include, but are not limited to, physical and personnel hazards. For further information see: https://www.cisc.gov.au/legislative-information-and-reforms/critical-infrastructure.

6.7. Summary of total capex forecast

The table below presents the total gross and net capex forecasts of $563.0 million and $521.9 million, respectively, for the forthcoming access arrangement period.

Table 6.17: Total capex forecast ($2023, $m)

Driver	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Customer connections*	46.3	47.6	49.0	48.0	46.9	237.9
Mains replacement	31.1	28.3	25.6	29.0	20.2	134.1
Regulators	5.6	5.0	4.4	4.5	4.8	24.3
Meters	6.4	7.5	8.1	6.5	5.7	34.2
Cathodic Protection	0.4	0.4	0.4	0.4	0.4	2.1
SCADA	1.3	1.2	0.3	0.3	0.3	3.3
Augmentation	5.0	6.6	3.7	2.2	5.9	23.3
ICT	16.3	18.7	20.3	10.2	7.6	73.0
Other*	5.5	6.8	7.8	5.7	4.9	30.6
Total gross capex	**117.8**	**122.2**	**119.5**	**106.8**	**96.7**	**563.0**
Customer contributions	(8.1)	(8.2)	(8.4)	(8.3)	(8.1)	(41.1)
Total net capex	**109.7**	**113.9**	**111.2**	**98.5**	**88.5**	**521.9**

Source: AusNet

Note: Some components in both the 'Customer connections' and 'Other' categories lead to up-front payments from customers. These are summated into the 'Customer contributions' category in Table 6.17.

6.8. Conforming capex assessment

Part of the adjustment to the capital base at each access arrangement review is to add to the value of the capital base the amount of 'conforming capital expenditure' made, or to be made, during the earlier access arrangement. For the purpose of this adjustment, this section assesses whether the capital expenditure incurred during the current access arrangement period meets the requirements for 'conforming capital expenditure'.

Rule 79(1) of the NGR requires that to be conforming capital expenditure, it must conform with the following criteria:

> *(a) the capital expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services; and*
>
> *(b) the capital expenditure must be justifiable on a ground stated in subrule (2);*
>
> *and*
>
> *(c) the capital expenditure must be for expenditure that is properly allocated in accordance with the requirements of subrule (6).*

Rule 79(2) states that capital expenditure is justifiable if:

> *(a) the overall economic value of the expenditure is positive; or*
>
> *(b) the present value of the expected incremental revenue to be generated as a result of the expenditure exceeds the present value of the capital expenditure; or*
>
> *(c) the capital expenditure is necessary:*
>
> > *(i) to maintain and improve the safety of services; or*

(ii) to maintain the integrity of services; or

(iii) to comply with a regulatory obligation or requirement; or

(iv) to maintain the service provider's capacity to meet levels of demand for services existing at the time the capital expenditure is incurred (as distinct from projected demand that is dependent on an expansion of pipeline capacity); or

(d) the capital expenditure is an aggregate amount divisible into 2 parts, one referable to incremental services and the other referable to a purpose referred to in paragraph (c), and the former is justifiable under paragraph (b) and the latter under paragraph (c).

We consider that the capital expenditure we incurred (or are still yet to incur) in the 2018-23 access arrangement period meets the requirements of conforming capex for the purposes of rule 79 of the NGR.

The Capital Expenditure Efficiency Scheme (CESS) was introduced at the start of the 2018 access arrangement period and is designed to provide an increased and constant incentive to improve the efficiency of our capital expenditure. We forecast that during the current period, we will spend 5.4% less than the net allowance (or 0.2% more than the gross allowance) and consider this to be prima facie evidence that our capital program is efficient and conforms with the requirements of rule 79 of the NGR. We have also met our performance targets under the Asset Performance Indicator (API) component of the CESS, which demonstrates that we have not reduced capex at the expense of the safety and reliability of the network.

In the paragraphs below, we summarise why our expected capex for each major expenditure category is conforming capex.

- New customer connections. In the current period, we expect to incur $296.2 million (gross) or 53% of our capex in connecting new customers. The Gas Distribution Code of Practice required that we use an NPV test in deciding whether to levy a connection charge on a new connecting customer. This NPV test checks whether the present value of the expected incremental revenue to be generated as a result of the expenditure exceeds the present value of the capital expenditure (as required by rule 79(2)(b)). If the NPV of the connection is not positive, then a capital contribution, which is sufficient to make the connection NPV positive is required. This approach to connection charging ensures that our expenditure on connecting new customers is NPV positive and so this expenditure meets the requirements of rule 79(2)(a).
- Mains replacement program. In the current period, we expect to incur $130.5 million or 23% on our mains replacement program. The mains replacement programs are a key safety and reliability program and is critical to maintain and improve the safety of services, as required by rule 79(2)(c)(i)).
- Meter replacement program. In the current period, we expect to incur $43.5 million or 8% on the meter replacement program. Our meter replacement program is required to ensure compliance with our regulatory obligations, including those contained in the Gas System Distribution Code of Practice. As such, this expenditure is required by rule 79(2)(c)(iii). To meet these obligations, we must maintain these installations, replace meters when their field life has expired, and provide metering information to retailers for billing and market settlement purposes.
- Augmentation program. In the current period, we expect to incur $16.2 million or 3% on our augmentation program. This program is required to maintain minimum pressure standards in areas where the usage of the network is increasing, in accordance with rules 79(2)(c)(ii), 79(2)(c)(iii) and 79(2)(c)(iv). Our approach to network planning and the CESS ensure that we seek the lowest cost option for network augmentation and so are prudent and efficient in accordance with clause 79(1)(a).
- SCADA, Regulators and Other programs. In the current period, we expect to incur $36 million (gross) or 6% on the SCADA, Regulators and Other programs. This is required to maintain the integrity of the network as per rule 79(2)(c)(iii).
- ICT program. In the current period, we expect to incur $40.4 million or 7% on the ICT program which is also required to maintain the integrity of the network as per rule 79(2)(c)(iii).

In each case, our capital expenditure is properly allocated in accordance with rule 79(6).

6.9. Supporting documents

In addition to the PTRM and RIN templates submitted with this proposal, we have provided the following key documents in support of our capex proposal:

- ASG – GAAR – Appendix 7 – Asset Management Strategy – 1 July 2022 – PUBLIC
- ASG – GAAR – Appendix 8 – AMS 30-01 – 1 July 2022 – PUBLIC
- ASG – GAAR – Appendix 9 – GAAR IT Strategy – 1 July 2022 – PUBLIC

A significant number of other supporting documents, including planning reports and ICT program briefs also form part of this proposal. [73]

[73] The financial figures in the plant strategies are presented in direct 2021 dollars and will not, therefore, match the amounts in this chapter which are presented in $2023 and include overheads and capital finance charges.

7. Operating expenditure

7.1. Key points

- Operating expenditure (opex) ensures the delivery of critical activities necessary to support the operation and maintenance of our assets, and the continued efficient management of our gas network.
- Our opex forecast has been prepared using the AER's preferred base-step-trend approach and has resulted in a $300.6 million forecast for the 2024-28 access arrangement period. Our forecast opex is 1.1% lower than our current period's approved allowance and 5.6% higher than our current period's forecast spend (real terms).
- In response to feedback from customers and stakeholders, we have removed several step changes and have absorbed $5.6 million of new costs. By absorbing these costs, and taking on the associated risk, we will help address stakeholders' concerns regarding affordability.
- Our benchmarking analysis demonstrates that our base year (CY2021) is efficient and therefore an appropriate input to forecast our opex over the 2024-28 access arrangement period.
- Other key aspects of our opex proposal include:
  - Including a capex to opex transfer of $11.5 million. While this increases our opex forecast, it reduces our capex program, and therefore leads to an overall benefit that is passed onto our customers.
  - Including $4.4 million for a Priority Services Program to support customers in vulnerable circumstances. Our program aligns with the Priority Services Programs proposed by AGN and MGN, and therefore ensures that customers receive consistent access to support and information across Victoria.
  - Removing $5.2 million from our base year opex to reflect our proposed recovery of Energy Safe Victoria's levies (ESV levies) from the control mechanism.
- We are proposing productivity savings of 0.4% per year, consistent with the AER's final decision for the AGN (SA) 2022-26 access arrangement. This is an ambitious target as we are one of the most efficient gas distribution networks in the country, and this is double the 0.2% per year our consultant recommended.

7.2. Chapter structure

The remainder of this chapter is structured:

- Section 7.3 summarises our opex forecast.
- Section 7.4 provides a description of our opex forecasting methodology.
- Section 7.5 provides information on customer feedback and how this has been used in preparing our opex forecasts.
- Section 7.6 explains the derivation of base year opex and the suitability of the base year for forecasting purposes.
- Section 7.7 outlines our proposed rate of change.
- Section 7.8 sets out our proposed step changes.
- Section 7.9 sets out our proposed category specific forecasts.
- Section 7.10 lists the supporting documents for this chapter.

7.3. Summary of our opex forecast

Our forecast of opex is a prudent and efficient forecast that ensures we can continue to operate and maintain the gas network to a standard that ensures:

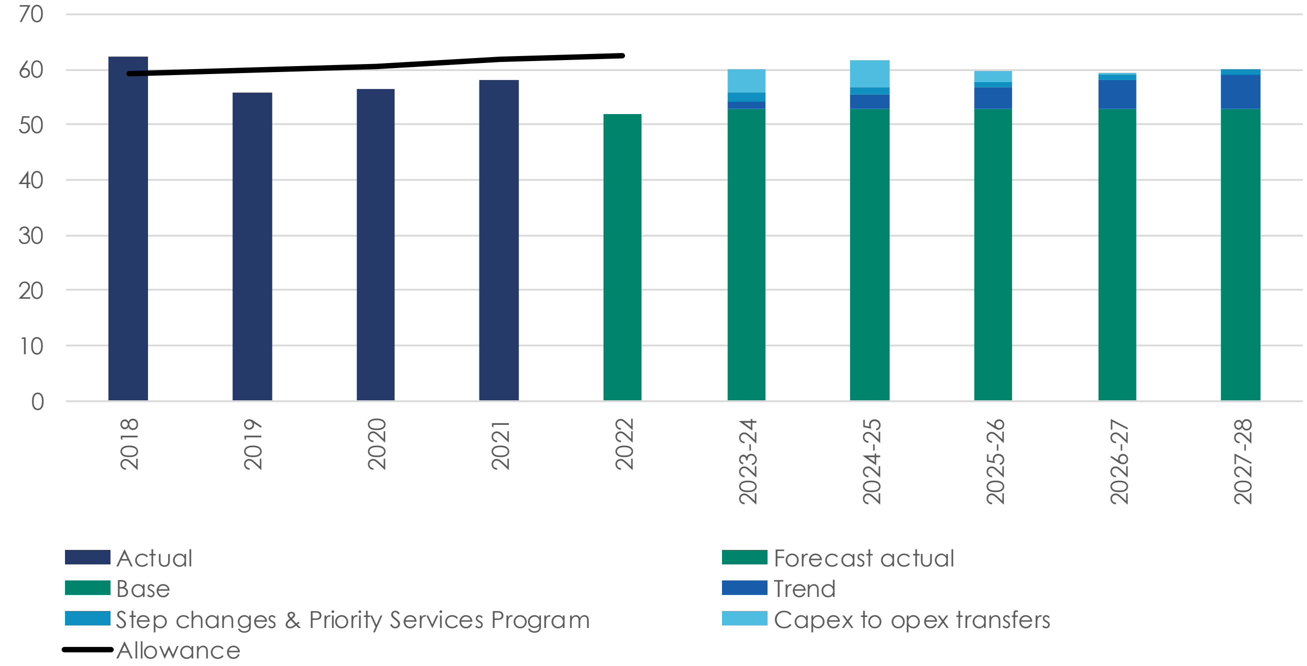
- Customers have access to a safe and reliable gas supply.
- We comply with all regulatory obligations and requirements.

We are forecasting a total opex of $300.6 million over the 2024-2028 access arrangement period which is (in real terms):

- 1.1% less than our current period's approved allowance.
- 5.6% greater than our current period's forecast actual spend.
- 10.7% less than our draft proposal.

Actual, estimated and forecast controllable opex for the current and forthcoming access arrangement periods are shown in the figure below.

Figure 7.1: Summary of operating expenditure forecast excluding debt raising costs ($m, real 2022-23)



Source: AusNet

One of the key differences between our opex proposal ($300.6 million) and that outlined in our draft proposal opex ($336.5 million) is that we are now proposing to use the control mechanism to recover ESV levies rather than have this captured in opex. Recovering these levies as a step change rather than via the control mechanism would increase our total opex to $331.9 million.

We have used the AER's preferred base-step-trend approach to develop a total opex forecast that is prudent and efficient and consistent with the NGR. Importantly, with a strong focus on affordability, we have proposed an opex allowance that minimises price increases to existing and future customers. Our opex forecast also ensures that we maintain the reliability and safety of our network services.

Our approved allowance for the last year of the current period (CY2022) is $62.6 million compared to our proposed forecast for the first year of the next period (2023-24) at $60.0 million. This represents an 4.2% decrease from the last year of the current access arrangement period to the first year of the forthcoming access arrangement period, primarily driven by our proposed recovery of the ESV levies via the control mechanism.

We are using CY2021 as our base year and have demonstrated its efficiency by reference to our benchmarking analysis, which shows we are one of the most efficient gas networks in Australia.

We have proposed a capex to opex transfer (IT cloud and Software as a Service) of $11.5 million. While this increases our 'headline' opex forecast, it also reflects a reduction in our capex requirements.

Our forecast for the Priority Services Program ($4.4 million) to support customers in vulnerable circumstances is a category specific forecast. Category specific forecasts are forecast using a bottoms-up approach.

Following the feedback provided by the VGNSR and RRG, we have agreed to absorb $5.6 million in opex during the 2024-28 access arrangement period. We have been able to absorb these new cost pressures due to a company-wide cost reduction program.

We are also proposing to:

- Escalate labour by Wage Price Index (WPI) consistent with an approach approved by the AER over several recent decisions.[74]
- Apply a productivity saving of 0.4% per year, which the AER approved for AGN (SA).[75] This productivity saving is double the 0.2% per year that our consultant has recommended.[76]

The components of our proposed opex forecast are set out in the table below.

Table 7.1: Summary of operating expenditure forecast ($m, real 2022-23)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Base	52.9	52.9	52.9	52.9	52.9	264.7
Trend	1.2	2.4	3.8	5.0	6.2	18.6
Capex to opex transfers	4.3	5.1	1.8	0.4	(0.1)	11.5
Step changes	0.0	0.4	0.3	0.4	0.3	1.4
Priority Services Program	1.6	0.9	0.6	0.6	0.6	4.4
Total opex excluding debt-raising cost	**60.0**	**61.7**	**59.5**	**59.4**	**60.0**	**300.6**
Debt raising cost	0.9	0.9	0.9	0.9	0.9	4.5
Total opex including debt-raising cost	**60.9**	**62.6**	**60.5**	**60.3**	**60.9**	**305.1**

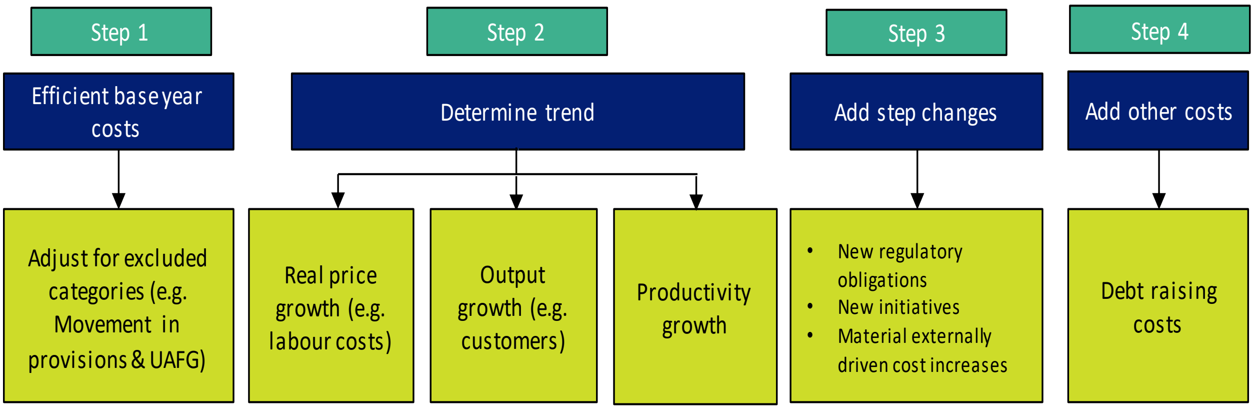
Source: AusNet
Note: Excludes ESV levies as we have proposed its recovery via the control mechanism.

7.4. Opex forecasting methodology

We have adopted the AER's preferred base-step-trend approach to forecast our opex for the 2024-28 access arrangement period. This involves building up the forecast from an efficient base year, trending forward the base year opex for changes in inputs, outputs and productivity, and then adding expected step changes in costs that have not been captured in the base or trend parameters. We then add category-specific forecasts, such as debt raising costs, to complete the opex forecast. This approach is illustrated in the figure below.

[74] AER 2021, Australian Gas Networks (SA) Access Arrangement 2021 to 2026, Attachment 6 Operating expenditure, Final Decision, April, p. 17. AER 2022, AusNet Services Transmission Determination 2022 to 2027, Attachment 6 operating expenditure, Final Decision, January, pp. 6 - 18.
[75] AER 2021, Australian Gas Networks (SA) Access Arrangement 2021 to 2026, Attachment 6 Operating expenditure, Final Decision, April, p. 16.
[76] ACIL Allen 2022, Opex partial productivity study 2022, Report to Australian Gas Networks (VIC and Albury), Multinet and AusNet, June, pp. 45–7.

Figure 7.2: Opex forecasting methodology



Source: AusNet

We have used the AER's preferred revealed cost method to establish the efficient base year opex. We have selected CY2021 as our efficient base year because it is the latest year for which audited data is available.

The revealed cost method and base-step-trend approach recognises that the Efficiency Benefit Sharing Scheme (EBSS) provides strong incentives for network businesses to deliver efficient opex outcomes. The AER verifies the efficiency of the base year opex through benchmarking analysis. Section 7.6 demonstrates that our actual expenditure for CY2021 is efficient and therefore appropriate for the purpose of forecasting opex over the 2024-28 access arrangement period.

7.5. Customer expectations and preferences

We have completed significant customer research to support our proposal which has been complemented by the insights and feedback provided by the VGNSR and RRG.

The stakeholder engagement process is not a substitute for detailed analysis and modelling. Rather, it provides valuable insights into stakeholders' expectations and priorities which supplements our analysis. A detailed description of the stakeholder engagement process that we have undertaken is provided in Chapter 5. However, in the context of this chapter, it is worth noting the information outlined below.

Table 7.2: Customer feedback and our response

Draft proposal	What we heard	How we have responded
Total opex forecast of $336 million excluding debt raising cost and ancillary reference services	Beyond the future of gas, customers told us that maintaining a safe and affordable network is highly important to them. As are maintaining reliability, providing quality customer service, innovating to better meet key needs and educating customers on key gas matters.	We have reviewed our opex forecast and reduced it where we can. Our opex forecast has reduced from $336.5 million to $331.9 million (if we recover the ESV levies as a step change rather than via the control mechanism) partly as a result of agreeing to absorb $5.6 million in new costs and updating the Priority Services Program and IT cloud and Software as a Service (SaaS) costs to reflect the latest information.
Productivity growth of 0.4% per annum	Stakeholders questioned whether the 0.4% productivity per annum is sufficiently ambitious, and whether AGN's SA network is a good comparison. They asked us to provide more evidence to justify the productivity rate we proposed.	Our proposed productivity growth of 0.4% per annum is sufficiently ambitious (section 7.7.3). In response to stakeholder feedback, we engaged an external consultant (ACIL Allen) to develop a productivity forecast for us. Its best estimate is 0.2% per annum, significantly less than

Draft proposal	What we heard	How we have responded
		the 0.4% per annum we have proposed.
Bushfire insurance premiums step change of $3.6 million	There was limited feedback received on the bushfire premiums increase. One stakeholder questioned whether this step change was fair, given higher premiums for bushfire insurance are likely driven by risk on our electricity network (and not the gas network), and the step change might mean gas customers are paying more than their fair share.	In response to feedback, we have removed the bushfire insurance premiums step change. We will carry the risk of any increased premiums over the 2024-28 access arrangement period.
Priority Services Program (PSP) step change of $5.0 million	The concept of a PSP was well-received by customers and other stakeholders. End-use residential customers were broadly supportive of AusNet establishing a PSP, so long as it did not compromise affordability. Feedback on the PSP included: • A strong preference from social service organisations for a consistent program across the state. • Some sentiment that AusNet should assume the whole cost of the program / roll into BAU. • A need to continue conversations about design and implementation in the lead-up to the program being established if it is approved by the AER. • That AusNet should fund all overheads for the program. • Concern that the funds were allocated and the program was costed prior to designing the program. One stakeholder raised concern that introducing the PSP would see us 'expanding operations' during uncertainty (inference that we should be winding down). Other stakeholders considered that such a program would become more important to protect vulnerable customers during the transition.	Following further consultation with customers, we have included a PSP in our proposal, albeit with some updates. We plan on introducing some initiatives at no extra cost. That is, these initiatives will be introduced even if the AER rejects the PSP. Based on strong feedback on the need for consistency, we have fully aligned our PSP inclusions with AGN & MGN's programs. Program inclusions have been developed with community organisations' input. Costs have been revised down to reflect new information ($4.4 million), and we have not included overheads in our cost build up. We will also continue working with stakeholders and customers on the detailed design and implementation of the program (outside this process).
Engineering initiatives and new state tax and levies step change	Stakeholders gave feedback that these step changes are very small. They questioned whether proposing them as step changes was justified,	In response to feedback, we have removed these step changes and will fund these new costs via our base opex. We will also assume the risk of these costs increasing over the 2024-

Draft proposal	What we heard	How we have responded
	and whether they should be rolled into the base spend. There was very limited discussion or feedback on the detail of these step changes.	28 access arrangement period via our base opex.
IT cloud and Software as a Service (SaaS) cost	We heard strong feedback from stakeholders to minimise discretionary IT spend. Stakeholders do not have a particularly strong understanding of IT programs and we received limited detailed feedback on IT-related aspects of our proposal. Stakeholders told us that they find it hard to engage meaningfully on this topic and acknowledged that the business does need IT to operate, but stressed they want us to spend conservatively, and do not feel we need state-of-the-art IT systems. We were asked to ensure that our proposed IT program did not include items that had already been approved in our electricity distribution or transmission price resets.	In response to feedback, we have reassessed our IT step change and reduced it from \$17.9 million to \$11.5 million.

Source: AusNet

7.6. Base year opex

To ensure the AER's preferred base-step-trend forecasting approach produces a prudent and efficient opex forecast, an efficient level of base year opex must be selected.

We have nominated the 2021 calendar year as the base year for forecasting opex because:

- It is the latest year for which audited data is available.
- Our internal benchmarking and analysis demonstrate that it is efficient – since 2007, we have been continually ranked as one of the most efficient gas businesses amongst our peers.
- Our assessment is that COVID-19 has not affected our opex costs.
- The revealed cost is efficient, given its incentives and interaction with the EBSS.

Notwithstanding identifying CY2021 as an efficient base year for the 2024-28 access arrangement period, we have made several adjustments to our actual CY2021 expenditure to ensure it is representative of efficient and recurrent costs. The negative adjustments are set out below:

- ESV levies because we have proposed its cost recovery via the control mechanism (explained in section 7.6.1 below).
- Movements in provisions in accordance with the AER's preferred approach.
- UAFG because it reflects the transfer from AusNet to retailers (retailers to AusNet) for gas losses above (below) the ESC's benchmark, and therefore the efficient level is deemed to be zero (i.e., when the UAFG on our network is in line with the ESC's benchmark).
- Non-reference services because it is not within the scope of reference services.

- Ancillary reference services (ARS) because this is consistent with the AER's template whereby the forecast for ARS is separately built up and identified.
- Debt raising costs because a more appropriate treatment is to forecast it on a category-specific basis.

On the other hand, we have made a positive adjustment to account for a change in our capitalisation approach for corporate overheads (see section 7.6.2 below).

Table 7.3 (below) sets outs the process for adjusting our CY2021 actual expenditure to derive the base year opex. This recurrent cost base includes shared corporate costs allocated to the gas network in accordance with our cost allocation method. We have not identified any non-recurrent costs in CY2021 that should be removed for forecasting purposes.

The base year is 14% lower than the base year used for the current access arrangement period, reflecting the benefit from efficiencies flowing to customers (real terms).

Table 7.3: Derivation of base year opex ($m)

	Base year opex
Total opex in CY2021 (nominal)	56.5
Less Movement in provisions	-1.2
Less Unaccounted for Gas (UAFG)	0.0
Less Non-reference services	4.3
Less Ancillary reference services (ARS)	1.9
Less Debt-raising costs (DRC)	0.0
Base year opex (nominal)	**51.5**
Plus Escalation and trend	6.3
Less ESV levies	5.7[77]
Plus capitalised corporate overhead	0.8
Base year opex (real 2022-23)	**52.9**

Source: AusNet

7.6.1. ESV levies

Section 8 of the *Electricity Safety Act 1998* (Vic) (ESA) requires us to make annual payments to the ESV in respect of its reasonable costs and expenses as determined by the relevant Minister (via a Levy Scheme). The ESV levies is an annual levy that is determined exogenously. We have experienced unexpected and substantial increases in the ESV levies over recent years (see the table below).

[77] Real 2022-23 dollars, or $5.2 million in real 2021 dollars.

Table 7.4: ESV levies ($m, nominal)

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
ESV levies	3.1	3.3	3.5	3.7	4.4	4.8	5.5	5.6
% Increase		**5.5**	**5.8**	**5.9**	**20.0**	**10.4**	**13.2**	**2.8**

Source: AusNet
Note: ESV levies in 2022-23 are forecasts.

To ensure we only recover the prudent and efficient cost of the ESV levies, we are proposing to recover these levies via the control mechanism. This approach means customers will only pay for the exact levied amount – no more and no less.

To implement this approach, we are proposing to remove the ESV levies from our base year opex. Removing this from the base year is:

- Consistent with the treatment of ESV levies in the electricity distribution sector where the exact levies are recovered as a jurisdictional scheme amount in the control mechanisms formula. [78]
- Consistent with the AER's Draft Decision for AusNet's 2013-17 access arrangement, where it noted:

  … the AER proposes that gas distribution businesses include an additional element in the annual tariff variation mechanism that will recover the incremental amount of the ESV levy – that is, the amount above their proposed ESV levy related opex forecasts.[79]

Given new information on the level of the proposed increases, the AER's Final Decision approved a step change in lieu of the annual tariff variation mechanism. [80]

If the AER does not agree with our proposed use of the control mechanism to recover these costs, there should be no adjustment to our proposed base year and a new step change will be required. Where this is the case, we propose an ESV levies step change of $0.8 million to be included in our opex forecast (see Table 7.5 below).

We have calculated the step change ($0.8 million) by escalating our 2021-22 actual invoice by 2.8% to arrive at our 2022-23 forecast, and then adopting a 5% year-on-year increase for the period from 2023-24 to 2027-28. The 2.8% escalation is based on the ESV's 'Levies Determination' letter to us stating that the increase from 2021-22 to 2022-23 will be 2.8%. The 5% year-on-year escalation is the average of the actual growth rates from 2016-17 to 2018-19 and 2022-23. We have sought, but at the time of submitting this proposal had not received, the ESV's view on our calculation.

Table 7.5: ESV levies step change ($m, real 2022-23)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
ESV levies	0.1	0.1	0.1	0.2	0.2	0.8

Source: AusNet

This step change is not required if our control mechanism proposal is accepted. Recovery via the control mechanism is a superior approach to a step change because:

- It avoids the need to forecast these levies.
- Customers pay for the exact amount – no more and no less.
- It avoids the need for us to continually propose a step change for large increases in the ESV levies as seen in recent years.

7.6.2. Capitalised corporate overheads

Corporate overheads are costs related to corporate functions that are necessary to perform day-to-day tasks and activities. Our current practice is to capitalise a portion of corporate overheads that provide support to capital activities. However, we are proposing a change to the way we treat our capitalised corporate overheads because:

- While a transfer from capex to opex increases prices in the short term, it lowers prices in the longer term. Importantly, lower future prices are key to assisting the gas network to remain competitive if we transition to a hydrogen network or, where the gas network needs to be wound down, it assists in keeping keep prices lower for

[78] AER 2021, AusNet Services Distribution Determination 2021 to 2026, Attachment 6 operating expenditure, Final Decision, April, p. 35.
[79] AER 2012, Access arrangement draft decision SPI Networks (Gas) Pty Ltd 2013-17, Part 1, September, p. 223.
[80] AER 2013, Access arrangement final decision SPI Networks (Gas) Pty Ltd 2013-17, Part 1, March, p. 45.

remaining customers as demand reduces across the network. See Chapter 3 (The future of gas) for more information on our transition.

- It will deliver longer term benefits for customers as these costs will not increase the asset base and therefore incur a return on and return of capital.

While this will cause our statutory and regulatory accounts to be out of alignment, it can be explained as a difference in treatment between statutory and regulatory accounts. We note that there is no requirement for statutory and regulatory accounts to be consistent.

7.6.3. Demonstrating the efficiency of our base year

We have used CY2021's revealed expenditure to forecast our efficient base year opex for the 2024-28 access arrangement period.

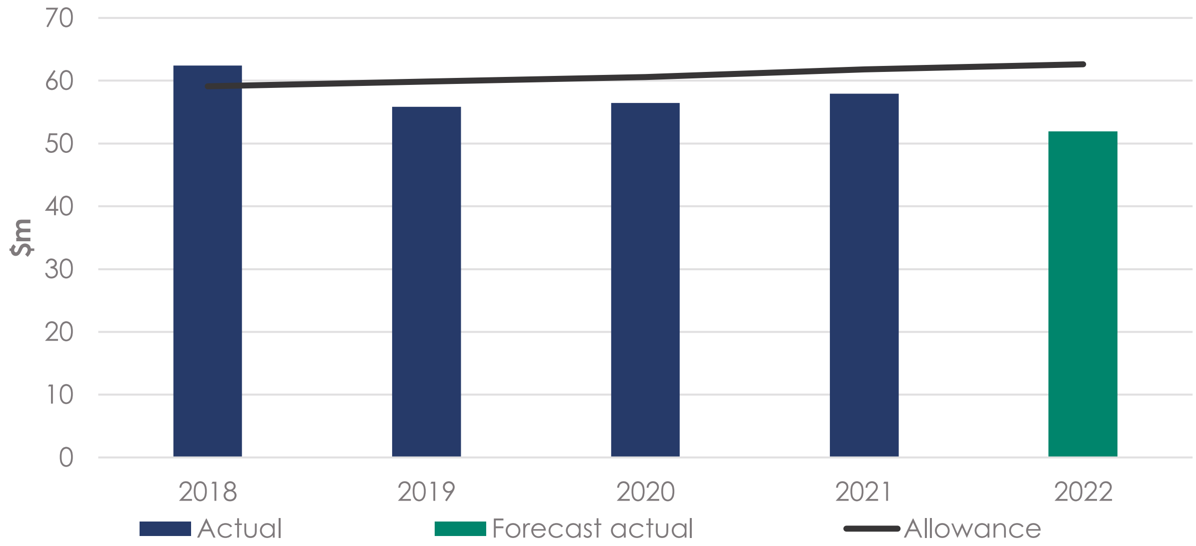
This is appropriate as:

- Our actual opex for 2021 was below the regulatory allowance for that year, demonstrating that we continue to respond positively to the incentive properties of the EBSS (see Figure 7.3 below).
- Our positive response to the EBSS is evidence that our actual opex is efficient.
- Rule 71(1) of the NGR states:

  In determining whether capital or opex is efficient and complies with other criteria prescribed by these rules, the AER may, without embarking on a detailed investigation, infer compliance from the operation of an incentive mechanism or on any other basis the AER considers appropriate.

The figure below shows our actual and forecast opex compared to the AER's allowance.

Figure 7.3: Actual/estimated opex versus benchmark allowance ($m, real 2022-23)



Source: AusNet
Note: Actuals/Estimated costs exclude debt raising costs, movement in provisions, UAFG, non-reference services and ancillary reference services.

In addition to examining our historical opex performance compared to the AER's allowance, we have undertaken benchmarking analysis to assess the efficiency of our base year opex, as explained in the next section.

7.6.4. Benchmarking

Benchmarking analysis is useful to gain an understanding of the relative efficiency between different businesses. Due to a conflict of interest that prevents the consultant that we have typically relied on for benchmarking, we have prepared our own benchmarking report to support the efficiency of our base year cost. Our report draws heavily on publicly available data taken from Economic Insight's analysis for the AGN (SA) 2021-26 determination, which is the latest benchmarking report for an Australian gas distribution business.[81]

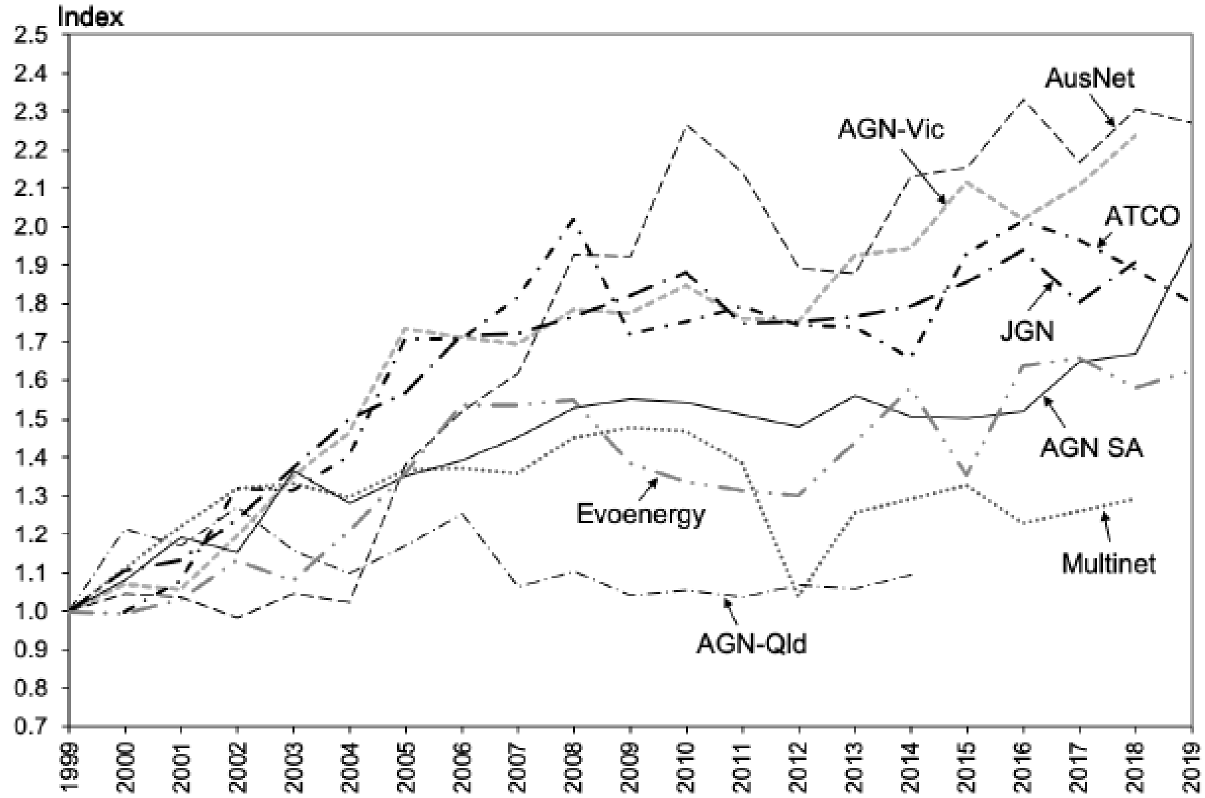
[81] Due to a conflict of interest, Economic Insights was unable to undertake this exercise for us. We have previously used (as have other gas businesses) this independent consultant to undertake benchmarking analysis to support proposals submitted to the AER.

While Appendix 11 provides a full description of our benchmarking exercise, the discussion and figures below summarise the key outcomes.

7.6.4.1. Opex partial factor productivity

Our opex partial factor productivity (opex PFP) growth has been particularly strong since 2007 relative to other gas distribution networks in Australia (see Figure 7.4 below). Specifically, our opex PFP is the strongest/highest of the businesses considered and has been for several years.

Figure 7.4: Opex partial factor productivity comparisons (1999-2019)



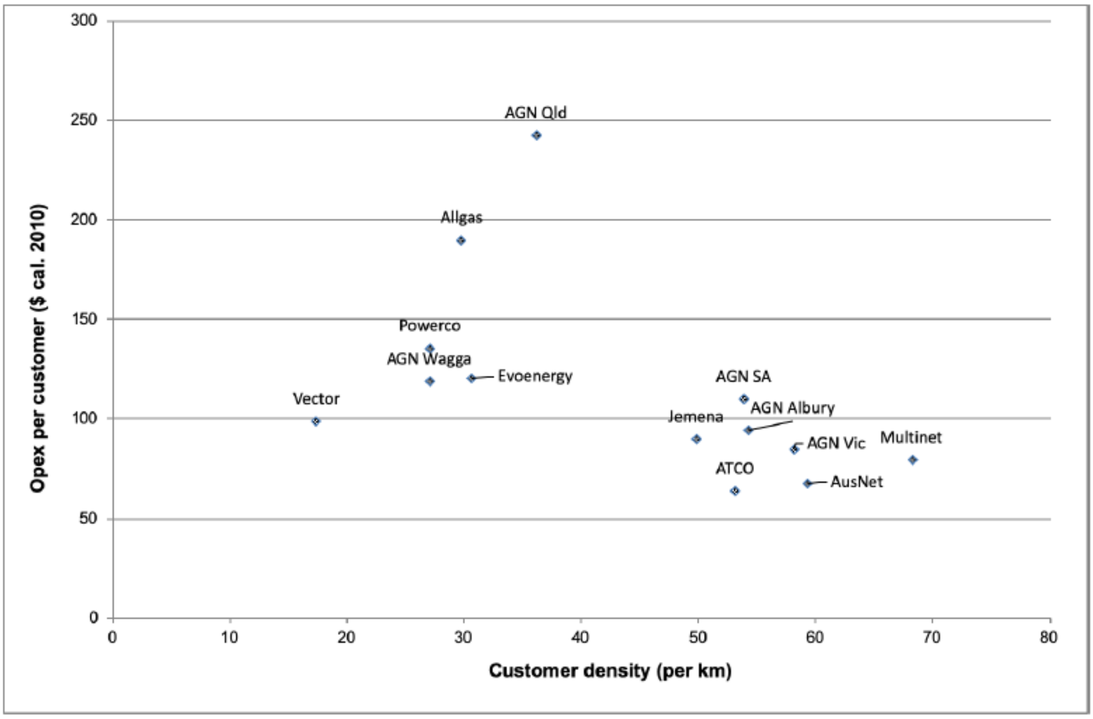
Source: Economic Insight 2021, The Productivity Performance of Australian Gas Network's South Australian Gas Distribution System, Report prepared for Australian Gas Networks (AGN), 15 June, Figure 3.5

Partial productivity indicators present information on the inputs per customer of Gas Distribution Businesses (GDBs) and inputs per mains km compared to their network customer densities. This is useful because by expressing inputs in per customer or per km values and plotting them against customer density, there is a form of control for differences in the size and customer densities of the GDBs. As such, partial productivity indicators play an important role in establishing the efficiency of the GDBs.

Economic Insight's partial performance indicators show that we compare well relative to other gas businesses:

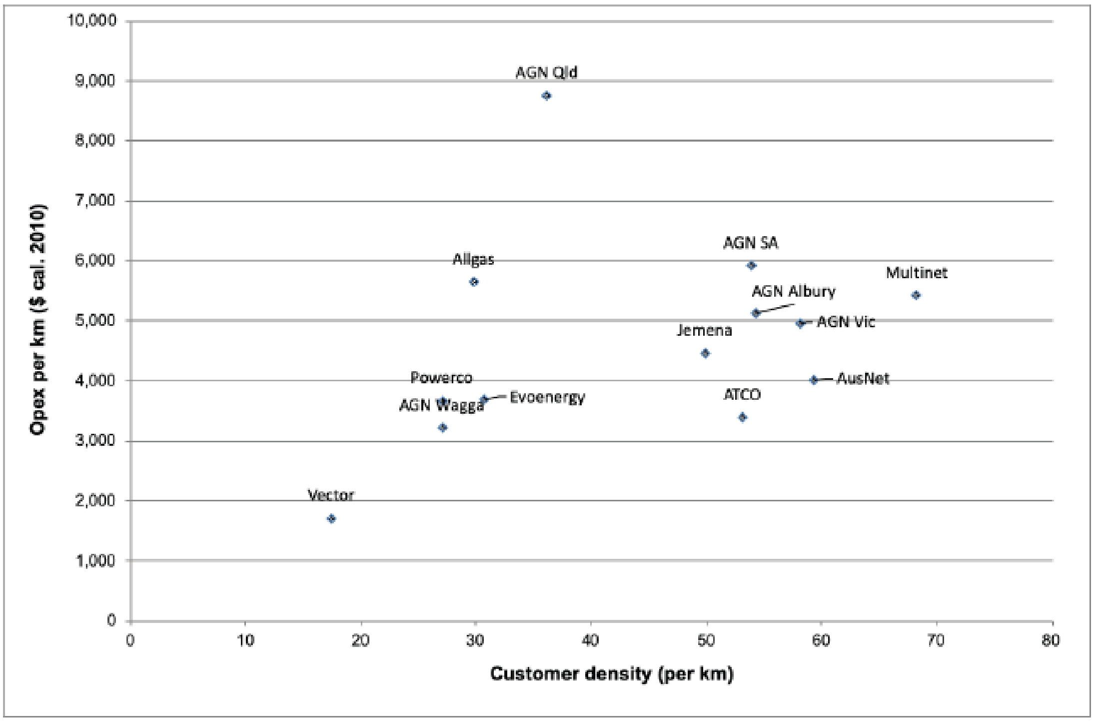
- Our average opex per customer (in $2010) over the latest five-year period (2015 to 2019) was $68, which is well below the average among the seven GDBs with similar and higher customer densities ($84) – see Figure 7.5.
- Our opex per km of mains was $4,020 over the latest five-year period, which is below the average of all GDBs in the sample ($4,614), and below the average of GDBs with similar and higher customer densities ($4,756) – see Figure 7.6.
- Our normalised real opex per customer is below the sample average under both methods used by Economic Insights – see Figure 7.7 and Figure 7.8.

Figure 7.5: Opex per customer relative to customer density (1999-2019)



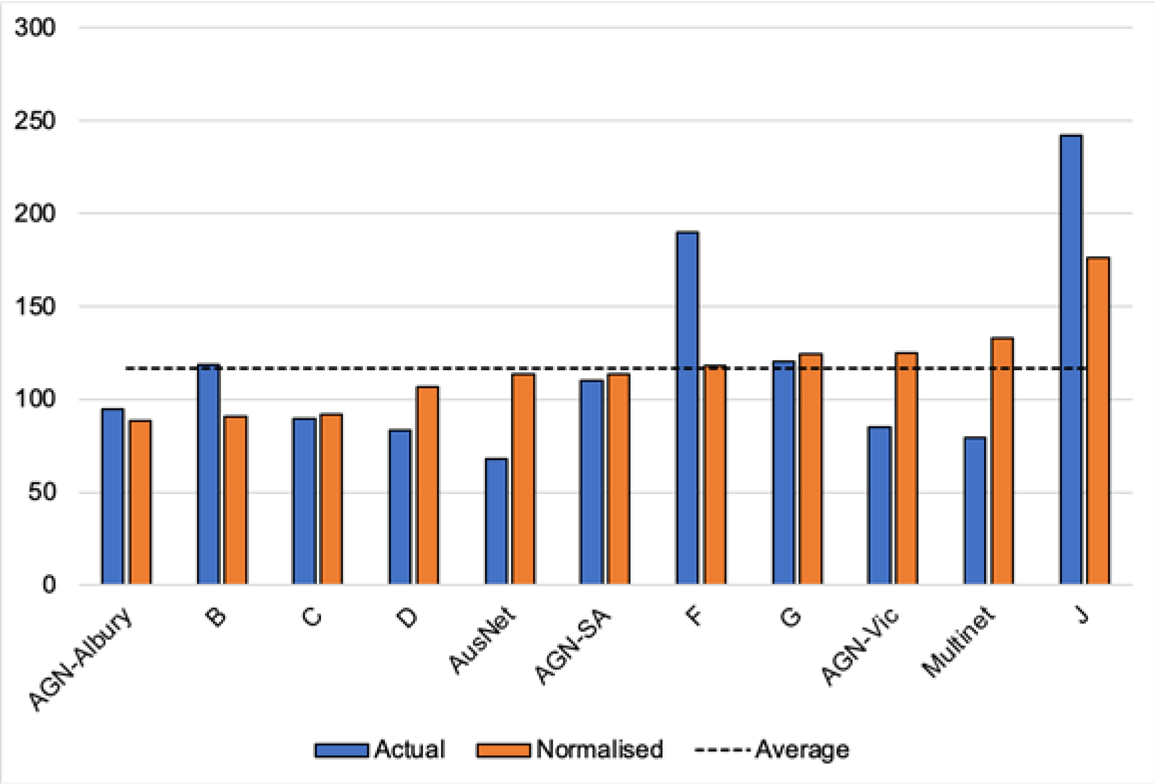
Source: Economic Insight 2021, Benchmarking Operating and Capital Costs of Australian Gas Network's South Australian Network Using Partial Productivity Indicators, Report prepared for Australian Gas Networks, 15 June, Figure 3.1

Figure 7.6: Opex per mains km relative to customer density (1999-2019)



Source: Economic Insight 2021, Benchmarking Operating and Capital Costs of Australian Gas Network's South Australian Network Using Partial Productivity Indicators, Report prepared for Australian Gas Networks, 15 June, Figure 3.2

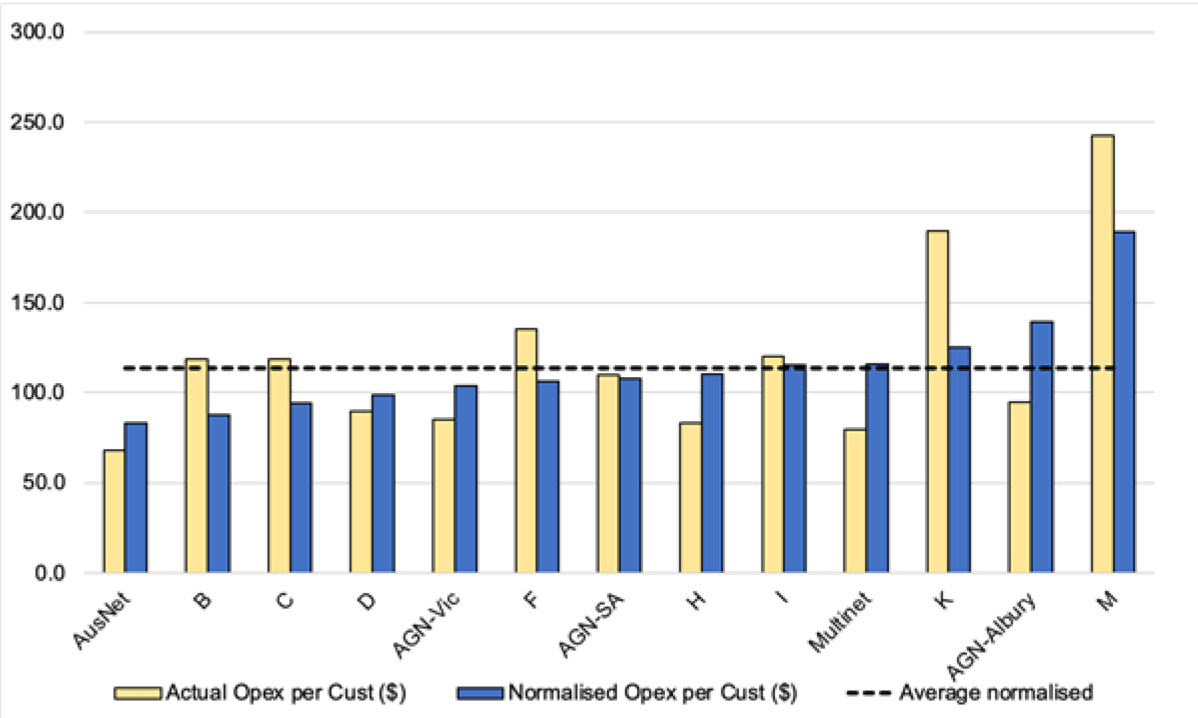
Figure 7.7: Normalised opex per customer (2015-2019) – 1st method



Source: Email from Economic Insights, 24 May 2022

Note: We engaged Economic Insights to reproduce Figure 3.8 (from its benchmarking report) albeit with the network businesses owned by AusNet and AGIG identified.

Figure 7.8: Normalised opex per customer (2015-2019) – 2nd method



Source: Email from Economic Insights, 24 May 2022

Note: We engaged Economic Insights to reproduce Figure 3.9 (from its benchmarking report) albeit with the network businesses owned by AusNet and AGIG identified.

In summary, these results demonstrate that we are an efficient business. By extension, our CY2021 revealed costs are, therefore, efficient and provide an appropriate base year for the purpose of forecasting our opex over the 2024-28 access arrangement period.

7.7. Rate of change

The AER's Expenditure Assessment Forecast Guideline explains that efficient opex in the forecast period may differ from the base year opex due to:

- **Real price growth**: changes in the prices paid for labour, materials and contractors;
- **Output growth**: changes in the scale of the network or demand for network services can affect the expenditure required to service customers and the network; and
- **Productivity growth**: changes in expenditure required to deliver the same level of services to customers may be driven by economies of scale, technical changes or efficiency improvements.[82]

As a result, and in line with the AER's Guideline, we have applied a rate of change to the base year opex that has been calculated using the following formula:

Rate of change = Output growth + Real price growth – Productivity growth

We have developed a forecast for each of the elements above and applied these to develop the 'trend' component of our opex forecast. Table 7.6 (below) provides an overview of our rate of change, while the following sections provide a discussion of each element.

However, we will revisit and update these parameters as appropriate for the Revised Proposal.

Table 7.6: Rate of change (%)

	2023-24	2024-25	2025-26	2026-27	2027-28
Output growth	2.2%	2.2%	2.2%	2.2%	2.1%
Real price growth	0.4%	0.6%	0.6%	0.4%	0.3%
Productivity growth	0.4%	0.4%	0.4%	0.4%	0.4%
Rate of change (YoY)	**2.2%**	**2.4%**	**2.4%**	**2.1%**	**2.0%**

Source: AusNet

7.7.1. Output growth

In its Explanatory Statement to the Expenditure Forecast Assessment Guideline, the AER states that:

> *Increased demand for NSPs' outputs may require them to expand their networks. It is reasonable that an efficient NSP will require more inputs, and thus greater opex, to deliver more output. We therefore include forecast output growth in the rate of change formula.*[83]

We agree that the rate of change should account for the impact of increased outputs on opex over the forthcoming access arrangement period.

We have, therefore, proposed output growth that is based on forecast changes in customer growth and mains length – this is different to the current access arrangement that is based on customer growth and gas throughput. We have amended our approach (including with respect to weighting) to ensure better alignment with the AER's more recent determinations for:

- AGN (SA) 2022-26 access arrangement.[84]
- Evoenergy 2022-26 access arrangement.[85]
- Jemena 2021-25 access arrangement.[86]

[82] AER 2013, Expenditure Forecast Assessment Guideline, Explanatory Statement, Better Regulation, November, pp. 67-8.
[83] AER 2013, Expenditure Forecast Assessment Guideline, Explanatory Statement, Better Regulation, November, p. 68.
[84] AER 2020, Australian Gas Networks (SA) Access Arrangement 2021 to 2026, Attachment 6 operating expenditure, Draft Decision, November, p. 27.
[85] AER 2020, Evoenergy Access Arrangement 2021 to 2026, Attachment 6 operating expenditure, Draft Decision, November, p .27.
[86] AER 2019, Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Attachment 6 operating expenditure, Draft Decision, November, p. 22.

- Multinet Gas 2018-22 access arrangement.[87]

Importantly our output growth parameters are consistent with the output growth parameters of ACIL Allen's productivity estimate. We also note that ACIL Allen's report suggests that customers and mains length exhibit a stronger relationship with opex than customers and energy throughput.[88, 89]

Table 7.7 below provides a summary of our output growth, where it is based on customer and mains length weightings of 45% and 55% respectively.

Table 7.7: Output growth rates (%)

	2023-24	2024-25	2025-26	2026-27	2027-28
Customer	2.2%	2.2%	2.2%	2.1%	2.0%
Mains length	2.2%	2.2%	2.2%	2.2%	2.2%
YoY growth	**2.2%**	**2.2%**	**2.2%**	**2.2%**	**2.1%**

Source: AusNet

7.7.1.1. Customer growth

We engaged CIE to develop an independent view of forecasts for customer growth in our network for the forthcoming access arrangement period.

Our customer base is forecast to grow by approximately 2.1% per annum over the course of the next access arrangement period. This is driven by strong household growth and strong levels of gas connections for new dwellings.

The forecast of household growth is sourced from the Victorian Government's 2019 Victoria in Future (ViF) planning document. The 2019 ViF growth rates for each LGA were used by CIE to grow the number of customers within each postcode. The penetration rate[90] established for each LGA by CIE was then applied to the household growth rate to forecast the number of new gas customers. The result is a customer number forecast at the postcode level, which can be used to forecast the number of customers in each of our pricing zones.

See Chapter 4 for more information on demand forecasting.

Table 7.8 (below) provides a summary of CIE's customer growth forecasts split by residential and commercial customers.

Table 7.8: Customer growth

	2023-24	2024-25	2025-26	2026-27	2027-28
Residential	779,829	797,292	815,283	832,736	849,632
Commercial	16,754	16,808	16,864	16,918	16,970
Total	796,583	814,100	832,147	849,654	866,602
YoY growth %	**2.2%**	**2.2%**	**2.2%**	**2.1%**	**2.0%**

Source: CIE

[87] AER 2017, Multinet Gas Access Arrangement 2018 to 2022, Attachment 7 operating expenditure, Draft Decision, July, pp. 7-23
[88] ACIL Allen 2022, Opex partial productivity study 2022, Report to Australian Gas Networks (VIC and Albury), Multinet and AusNet, June, pp. 42–7.
[89] ACIL Allen developed their productivity forecast based on customers/energy throughput and customers/mains length. The coefficients for mains length were 0.59 and 0.22 for FGLS and SFA respectively (table 8.2), whereas the coefficients for energy were 0.14 and 0.03 for FGLS and SFA respectively (from table 8.1).
[90] The proportion of dwellings that connect to gas.

7.7.1.2. Mains length growth

Our mains length forecast is based on historical data, trended forward by 2.2% per annum, which is the average growth rate over the past 10 years.

Table 7.9: Mains length growth

	2023-24	2024-25	2025-26	2026-27	2027-28
Mains length	13,004	13,299	13,601	13,910	14,226
YoY growth %	**2.2%**	**2.2%**	**2.2%**	**2.2%**	**2.2%**

Source: AusNet

7.7.2. Real price growth

The real price change component of the rate of change reflects expected changes in real input prices over the forthcoming access arrangement period. That such changes in real prices may occur is recognised by the AER in its Explanatory Statement to the Expenditure Forecast Assessment Guideline:

> *It is reasonable to assume that the cost of inputs for an efficient firm to produce the same level of output may change at a rate different to CPI. Consequently it is reasonable to account for real cost changes in inputs.*[91]

We agree with the AER and consider that the rate of change should account for the impact of increased input costs on opex over the forthcoming access arrangement period. For instance, our historical growth in labour costs has been higher than CPI, and this trend is expected to continue over the forthcoming access arrangement period.

Labour costs and materials costs are the two components that determine the real price impact on opex. The forecasting method we have adopted for these two components are:

- Labour costs: An average of forecast changes in the Victorian Wage Price Index (WPI) for electricity, gas, water and waste services, using forecasts from consultants Deloitte Access Economics (DAE) and BIS Oxford Economics.
- Materials costs: We assume that materials will grow in line with the CPI.

Table 7.10 (below) provides a summary of our output growth, where it is based on labour and materials weightings of 62% and 38% respectively. We have adopted these weights because it is consistent with our current 2018-22 Access Arrangement, and similar to the AER's recent decisions for AGN (SA)'s 2021-26 Access Arrangement, Evoenergy's 2021-26 Access Arrangement, and AusNet's 2022-26 EDPR.

Table 7.10: Input price growth

	2023-24	2024-25	2025-26	2026-27	2027-28
Labour	0.6%	0.9%	1.0%	0.6%	0.5%
Materials	0.0%	0.0%	0.0%	0.0%	0.0%
YoY growth (%)	**0.4%**	**0.6%**	**0.6%**	**0.4%**	**0.3%**

Source: CIE and AusNet

7.7.2.1. Labour costs

In line with historical trends, the costs of labour are expected to increase at a rate higher than CPI over the forthcoming access arrangement period. We have relied on expert independent advice (BIS Oxford Economics) to build up a rigorous forecast of expected labour price growth in the Electricity, Gas, Water and Waste Services (EGWWS) sector in Victoria based on expected macroeconomic and state specific factors. This consultant's report can be found in Appendix 10.

[91] AER 2013, Expenditure Forecast Assessment Guideline, Explanatory Statement, Better Regulation, November, p. 70.

This analysis shows that the National and Victorian utilities wages are forecast to increase by more than the national and state all industries averages due to:

- The electricity, gas and water sector being a largely capital intensive industry whose employees have higher skill, productivity and commensurately higher wage levels than most other sectors.
- Strong union presence in the utilities sector that will ensure outcomes for collective agreements, which cover 65% of the workforce, remain above the wage increases for the national 'all industry' average. In addition, with the higher proportion of employees on EBAs, compared to the national average (38%), and EBAs wage rises normally higher than individual agreements, this means higher overall wage rises in the EGWWS sector.
- Increases in individual agreements (or non-EBA wages) are expected to strengthen from the current subdued pace as the labour market tightens, especially from mid-2022 when the unemployment rate is expected to fall and remain below 4%.
- Demand for skilled labour picking up and strengthening with the high levels of utilities investment from FY22 to FY28, with overall utilities investment levels expected to remain elevated over the next seven years. This will also be a key driver of wages going forward.
- The overall national average tending to be dragged down by the lower wage and lower skilled sectors such as the Retail Trade, Wholesale Trade, Accommodation, Cafés and Restaurants, and, in some periods, also Manufacturing and Construction. These sectors tend to be highly cyclical, with weaker employment suffered during downturns impacting wages growth (such as what occurred in the wake of COVID-19). The EGWWS sector is not impacted in the same way due to its obligation to provide essential services and thus retain skilled labour.

The EGWWS index has been applied to labour because the broad mix of occupations it comprises are reasonably reflective of the composition of our labour mix.

We propose to adopt an average of the forecasts provided by the AER's consultant (typically DAE) and BIS Oxford Economics for labour costs. This averaging approach is consistent with the AER's recent determinations in AusNet's 2023-27 Transmission Revenue Reset (TRR) and 2022-26 Electricity Distribution Price Review (EDPR).

Table 7.11 (below) shows BIS Oxford Economics' forecast of real changes in Victoria's WPI for the EGWWS industry over the 2024-28 access arrangement period. We have adopted DAE's forecasts from the AER's Final Determination for AusNet's 2023-27 TRR as placeholder values (also in Table 7.11). An average of the two forecasts is also presented.

An update to BIS Oxford Economics' forecast below will be sought for the Revised Proposal.

Table 7.11: WPI forecasts

	2023-24	2024-25	2025-26	2026-27	2027-28
DAE	0.2%	0.4%	0.5%	0.3%	0.3%
BISOE	1.0%	1.4%	1.5%	0.9%	0.7%
Average	**0.6%**	**0.9%**	**1.0%**	**0.6%**	**0.5%**

Source: : DAE, BIS Oxford Economics and AusNet

7.7.2.2. Materials costs

We have applied a real cost escalation of 0% for materials, consistent with the AER's final determinations several recent decisions.[92]

7.7.3. Productivity growth

We are proposing to apply a productivity growth of 0.40% per year over the forthcoming access arrangement period. This is consistent with the AER's Final Decision for the AGN (SA) 2021-26 access arrangement.

In our draft proposal, we proposed productivity growth of 0.4% per annum and stakeholders questioned whether it is sufficiently ambitious, and whether the AGN (SA) example is a good comparison. Based on this feedback, we engaged an independent consultant (ACIL Allen) to review our proposed productivity rate. ACIL Allen

[92] AGN (SA) 2022-26 access arrangement, Evoenergy 2022-26 access arrangement, Jemena (NSW) 2021-25 access arrangement, TasNetworks 2021-24 access arrangement, Victorian 2022-26 electricity distribution price reviews, AusNet 2023-27 transmission revenue reset and Powerlink 2023-27 transmission revenue reset. We have used the AER's Draft Decision for Powerlink's 2023-27 transmission revenue reset because the Final Decision is not yet available.

recommended the use of productivity growth factor of 0.2% per annum.[93] This is significantly lower than the productivity growth we have proposed (0.4% per annum) and demonstrates the ambitious nature of our proposal.

Table 7.12: Productivity growth

	2023-24	2024-25	2025-26	2026-27	2027-28
Productivity	0.4%	0.4%	0.4%	0.4%	0.4%

Source: AusNet

7.7.3.1. Consistency with the AER's latest decision

A productivity growth of 0.4% per year is consistent with the AER's latest decision in the gas distribution sector i.e., the AGN (SA) 2021-26 access arrangement. [94]

7.7.3.2. Above ACIL Allen's productivity estimate

ACIL Allen's productivity estimate for AusNet and AGIG is 0.20% per year (an average of its four estimates that ranged from 0.14% to 0.24% per year).[95] This suggests that our proposed productivity growth of 0.4% is ambitious because:

- It is double the recommended productivity growth for AusNet and AGIG.
- It is above the upper limit estimate for AusNet and AGIG i.e., 0.24% per year.

7.7.3.3. Outlook

A productivity growth of 0.4% per year is ambitious because gas outputs are forecast to fall under some likely future scenarios, which means the opportunity for efficiency improvement becomes very limited, if not reversed (like they did in electricity).

7.8. Step changes

We have proposed two step changes to reflect changes in costs that have not been captured in the base or trend parameters.

These two step changes reflect expenditure required by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.

IT cloud and Software as a Service (SaaS) is by far the larger of the two amounts, where it is a capex to opex transfer to ensure that we maintain the necessary functionalities to operate our network.

Table 7.14 (below) provides a summary of our step changes, while the following sections provide further discussion. We have also provided a brief discussion and explanation of the step changes that we have agreed to absorb via the base opex.

The *Security of Critical Infrastructure Act* (the SOCI Act) is changing the way we operate, and we are currently investigating how this might impact our opex forecast – we will communicate the outcome to the AER as soon as practicable.

[93] ACIL Allen 2022, Opex partial productivity study 2022, Report to Australian Gas Networks (VIC and Albury), Multinet and AusNet, June, pp. 45–7.
[94] AER 2021, Australian Gas Networks (SA) Access Arrangement 2021 to 2026, Attachment 6 Operating expenditure, Final Decision, April, p. 16.
[95] ACIL Allen 2022, Opex partial productivity study 2022, Report to Australian Gas Networks (VIC and Albury), Multinet and AusNet, June, pp. 45–7.

Table 7.13: Opex step changes ($m, real 2022-23)

Step change	Driver	Total
IT cloud and SaaS	Capex to opex transfer	11.5
Environmental Protection Act (EPA)	New regulatory obligation	1.4
Total		**13.0**

Source: AusNet

7.8.1. IT cloud and SaaS

This step change is made up of three interrelated components:

- **IT cloud implementation cost** that enables AusNet to move from the current on-premise solution to the cloud.
- **Software as a service (SaaS) implementation cost** that is a transfer from capex to opex, due to an accounting rule change that provided specific guidance on the treatment of implementation and customisation costs for cloud solutions.
- **IT cloud run cost** that is the day to day running cost to support our IT cloud environment.

We have discussed each component in the following sections – see table below for a summary of step change cost.

Table 7.14: IT cloud and SaaS cost ($m, real 2022-23)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
IT cloud implementation	1.5	1.0	2.7	1.6	1.6	8.5
SaaS	0.8	2.1	-2.8	-3.2	-3.6	-6.6
IT cloud run	2.0	2.0	1.9	1.9	1.9	9.7
Total	**4.3**	**5.1**	**1.8**	**0.4**	**-0.1**	**11.5**

Source: AusNet

7.8.1.1. IT cloud implementation

Software is increasingly moving to the cloud instead of the traditional capex approach where we purchase and maintain our own IT equipment and services (on-premise solutions). This trend is gaining momentum both within AusNet and internationally. Consequently, we require a step change to reflect this, noting that that this will place downward pressure on our capex requirements in the medium to long term.

Being the owner and operator of three different networks (electricity distribution, electricity transmission and gas distribution) we have shared services across functions, such as HR, finance and IT, whereby the corporate level expenditures are allocated to the individual networks based on our Cost Allocation Method (CAM).

There are five programs of IT investment (listed below) focussing on functions that are set to be migrated from an on-premise environment to the cloud environment, where the cost of the migration is not fully captured in the base or trend parameters. These functionalities are shared across all three network businesses where each network is allocated a percentage amount:

- Workforce collaboration.
- Corporate enablement.
- Information management.
- Corporate communications.
- Customer information systems.

In calculating the **shared services component**, we have adopted the same forecasting approach and assumptions as that for EDPR and TRR, including the assumption that the gas network will be allocated 21% of the shared IT costs.

This approach was accepted by the AER.[96] Then there are **gas specific** costs that are fully allocated to the gas network because it is the only user of the software.

The table below summarises our IT cloud implementation cost.

Table 7.15: IT cloud implementation ($m, real 2022-23)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Gas component of shared services	0.5	0.5	0.5	0.5	0.5	2.6
Gas specific	1.2	0.7	2.4	1.3	1.3	6.9
Sub-total	1.7	1.2	2.9	1.8	1.8	9.4
Subtract actual + trend	0.2	0.2	0.2	0.2	0.2	0.9
Step change	**1.5**	**1.0**	**2.7**	**1.6**	**1.6**	**8.5**

Source: AusNet

7.8.1.2. Software as a service implementation

Previously, the Australian Accounting Standards Board (AASB) 138 document on Intangible Assets did not provide guidance on the treatment of implementation and customisation costs for cloud arrangements. Historically, we treated our SaaS subscription costs as opex, but capitalised the implementation and customisation costs.

A recent Agenda Decision (April 2021) by the International Accounting Standards Board (IASB) has provided explicit guidance (that was previously absent) that all implementation, customisation and subscription costs must be treated as opex.

As a result of the IASB decision, we have reviewed our SaaS projects and have subsequently reclassified an amount from capex to opex over the 2024-28 access arrangement period (see table below). As explained earlier, the net impact on our total expenditure is zero.

The table below summarises our SaaS implementation cost, where we have netted off our CY2021 actual spend (including trend) to develop the negative step change.

Table 7.16: Software as a service implementation cost ($m, real 2022-23)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Software as a service	4.3	5.7	0.9	0.5	0.2	11.6
Subtract actual + trend	3.5	3.6	3.6	3.7	3.8	18.2
Step change	**0.8**	**2.1**	**-2.8**	**-3.2**	**-3.6**	**-6.6**

Source: AusNet

7.8.1.3. IT cloud run cost

IT cloud run cost are the daily cost to operate our IT cloud solutions once they have been implemented. These include the costs to host and maintain the cloud environment. The table below summarises our IT cloud run cost.

[96] AER 2021, AusNet Services Transmission Determination 2022 to 2027, Attachment 6 operating expenditure, Draft Decision, June, p. 27. AER 2021, AusNet Services Distribution Determination 2021 to 2026, Attachment 6 operating expenditure, Final Decision, April, p. 49.

Table 7.17: IT cloud run cost ($m, real 2022-23)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
IT cloud run cost	5.8	6.1	6.3	6.6	6.8	31.6
Subtract actual + trend	3.9	4.1	4.4	4.6	4.9	21.9
Step change	**2.0**	**2.0**	**1.9**	**1.9**	**1.9**	**9.7**

Source: AusNet

7.8.2. Environmental Protection Act

The amendments made to the *Environmental Protection Act 2017* (Vic) by the Environment Protection Amendment Act 2018 came into effect on 1 July 2021. The new legislation is a proactive regulatory approach focusing on preventing harm. In practical terms, we must now take positive steps to assess and manage the inherent and residual risks to human health and/or the environment if we have reasonable grounds for believing there may be contamination. This exposes us to an additional class of potential costs that we have not previously been exposed to. The approach required under the amended Act represents a departure from the prior regime, which focused on how to respond to an imminent threat to human health or the environment, or to manage pollution once it has occurred. The change in approach necessarily requires that we change the way we manage our environmental obligations going forward.

Our step change amount is based on several factors, including undertaking soil and groundwater testing at selected sites. Appendix 13 provides for more information including our bottoms-up calculation.

Table 7.18: EPA ($m, real 2022-23)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
EPA	0.0	0.4	0.3	0.4	0.3	1.4

Source: AusNet
Note: 2023-24 is showing zero due to rounding to the nearest decimal place.

7.8.3. Step changes that we have absorbed

In response to stakeholder feedback, we have agreed to absorb $5.6 million of new costs via our base opex. We are therefore exposed to the risks of these costs – including material increases above expectation – which are externally imposed or not within our control. These costs are:

- **Bushfire insurance premiums ($3.6 million)**: Due to bushfires and other climate related changes, we have seen a hardening in the insurance market where premiums have been rapidly increasing while cover has been decreasing – some players have exited the market entirely. As a result, our bushfire insurance premiums have been increasing at both the corporate level and network level because we purchase at the corporate level and then allocate to the individual network businesses.
- **Upgrading custody transfer meters ($1.5 million)**: APA recently undertook a review of AusNet's metering facilities as a part of their 5-yearly CTM metering strategy and identified three high priority sites requiring upgrades (three city gate sites in Werribee). Our contractual agreement with APA means they have the right to amend the relevant connection agreements and pass through the cost of the upgrade works to us.
- **New state tax and levies ($0.3 million)**: The Victorian Budget 2021-22 announced increases to land tax from 2022, and the introduction of a new Mental health and wellbeing levy that will take effect on 1 January 2022.
- **Transmission pipeline inline inspections ($0.1 million)**: Our pipelines are getting older and unforeseen integrity issues are becoming more apparent. To maintain the security of supply and public safety, we need to inspect our pipelines using an intelligent tool called a pipeline inspection gauge.
- **Digital meter trial program ($0.1 million)**: A program to roll out 1,000 digital meters, to inform us of the market shift to digital meters, and to support the future of gas.

7.8.4. Summary of step changes

Table 7.19: Summary of step changes ($m, real 2022-23)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
IT cloud and SaaS	4.3	5.1	1.8	0.4	-0.1	11.5
EPA	0.0	0.4	0.3	0.4	0.3	1.4
Total	**4.3**	**5.3**	**2.1**	**0.7**	**0.2**	**13.0**

Source: AusNet

7.9. Category specific forecasts

7.9.1. Priority Services Program

The business case for the PSP can be found at Appendix 12.

7.9.1.1. Need for the Priority Service Program

The lives of our customers can change when they least expect them to. At any point in time, they can face circumstances that affect their use of, or access to, essential services. The impacts of COVID-19 and the increasing frequency of severe weather events highlights this observation.

A key pillar of our strategy is 'Customer Passion'. We believe no customers should have to choose between food on the table or paying gas bills, and that customers who experience extra barriers to accessing or engaging with their gas service should receive fit-for-purpose support. While support for customers in vulnerable circumstances has typically been the remit of energy retailers who manage the financial relationship with end customers, our customers and stakeholders have clearly told us that as the managers of the physical gas assets, we also have a role to play.

7.9.1.2. Stakeholder support and services to be introduced as BAU

The feedback provided throughout our customer workshops showed that 81% of customers supported the development of a PSP.

Through engagement we recognised that there are several initiatives that will be important for all customers. We are planning to introduce these at no extra cost to customers and no increase in operating expenditure allowance. They include:

- Additional training for front line staff to engage with empathy and sensitivity, and refer priority service customers to:
  - Our PSP.
  - The appropriate dedicated support services where required.
  - Their energy retailers' dedicated support programs.
- Additional 24-hour translation services for any service that we offer over the phone, including our key interactions: planned and unplanned outages, new connections, life support customers, and claims and complaints. This increases our ability to connect with customers with limited or no English language proficiency (access to over 160 different languages).
- Additional advice on efficient usage of gas or referrals to energy efficiency advice available through trusted organisations.

We will also continue to offer the services currently available to support customers in vulnerable circumstances, including:

- Management of life support customers, with tailored communications for key interactions.
- Field staff door knocking and talking to customers before disconnecting a gas supply.

7.9.1.3. Options analysis

We have considered the following options to implement the PSP and deliver benefits to customers in vulnerable circumstances. These are:

- Option 1 – Do not implement any additional measures to support customers.
- Option 2 – Implement all PSP initiatives at the mid-point on the scale of delivery.
- Option 3 – Implement all PSP initiatives at the full point on the scale of delivery.

Options 2 and 3 will deliver all prioritised initiatives, where the difference between them relates to manual/low technology changes and high technology/automated options (see figure below).

Figure 7.9: Scale of delivery for Priority Services Program Initiatives

Source: AusNet

7.9.1.4. Benefits

There are considerable risks associated with not providing support or recognising the circumstances of customers (option 1). As highlighted in the CPRC report for the AER on Exploring regulatory approaches to consumer vulnerability "essential service providers can exacerbate harm if they do not respond in an informed, sensitive way to the personal circumstances of their customers".

Customers require support at multiple stages of the customer journey. Focussing on debt and payment difficulty, while valuable, constrains the definition of vulnerability and those who may require other services e.g., CALD customers. This means whole cohorts of customers will continue to connect in with distributors, seeking additional help and support, but we are unable to service them efficiently and systematically.

Option 1 (no initiatives are delivered) is risky particularly during periods of uncertainty. We have heard consistent customer and stakeholder feedback about the need to look after customers experiencing vulnerability on our network, and that this increases in importance during periods of uncertainty and high costs of living. They are often also the least able to change how they interact with their gas service due to being renters, the high costs of changing or upgrading appliances, and the capacity and drive to engage with their energy services.

The key benefits of options 2 and 3 (implementing the PSP) will flow directly to customers:

- Removing any potential stigma and feelings of anxiety for customers in accessing additional support services and sharing their story with us. Customers will only have to tell their story once, without the burden of proof, or need to navigate a complex sign up process.
- Setting up a dedicated team of specialists who understand the nuanced experiences of customers in vulnerable and disadvantaged circumstances. The team's expertise will enable them to deliver more focussed and personalised customer service. This will result in faster and more sensitive case management of complaints and enquiries and allow them to identify opportunities to continuously improve the program. In addition, they will develop key referral programs that will enhance customers' access to a wider range of support.
- Reducing the financial barriers that some customers in vulnerable or disadvantaged circumstances face in terms of utilising gas more efficiently or ensuring their appliances are operating in a safe and reliable manner.
- Reducing anxiety and improving the feeling of safety and autonomy by assisting customers to read their own meter so that meter readers no longer need to physically visit their property.
- Improving the accessibility of both digital and printed communications that all AusNet customers interact with and rely on, specifically uplifting the experience of CALD customers who will have access to tailored, easy English communications in their native language. Customers will be better able to understand the key information being shared about their essential service.
- Providing additional support for customers who are experiencing an interruption to their gas supply. Rather than go without heating, hot showers or a warm meal, they can access these services at no cost to them.

7.9.1.5. Recommended option

Option 2 is the recommended option for our PSP as it delivers the highest value to customers, at the lowest cost. The initiatives involved in the program include:

- Establishing a Priority Services Register that allows customers to sign up easily online or be referred by third parties.
- Establishing a dedicated customer support team, consisting of 1 senior Priority Services (PSP) Team Lead and 1 mid-level Customer Service agent. They will be responsible for managing the program, developing referral programs for use by our customer service teams, implementing the new services identified and providing rapid and sensitive case management for customers on the program.
- Providing check-ins for Priority Services customers during outages, by proactively reaching out to those without gas and providing them with access to additional support services e.g., accommodation, temporary heating and cooking facilities.
- Enabling customers to read their own meters so that meter readers do not need to access their property.
- Improving communications with CALD customers, making key information available in multiple languages and easy English.
- Providing funding to support free gas appliance safety checks and emergency gas appliance repairs.

The table below outlines the forecast cost to deliver Option 2 (excluding overhead). This is equivalent to approximately $1.05 per customer per year, which is below the $1.30 spend that customers told us they were comfortable with.

The relevance of the PSP will be monitored and if the future of gas becomes clearer and we identify opportunities to adapt the program to our customers' changing needs, then we will seek to do this as quickly as practicable.

Table 7.20: Priority Services Program ($m, real 2022-23)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Priority Services Program – Option 2	1.6	0.9	0.6	0.6	0.6	4.4

Source: AusNet

7.9.2. Debt raising costs

Debt raising costs are the transaction costs incurred each time debt is raised or refinanced. These may include legal and banking fees, arrangement fees, company credit rating fees and other transaction costs.

We propose to forecast debt raising costs by applying 8.0 basis points per annum to the debt raised, in accordance with the AER's recent determination for AusNet's 2023-27 TRR.[97]

Table 7.21: Debt-raising cost ($m, real 2022-23)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Debt raising costs	0.9	0.9	0.9	0.9	0.9	4.5

Source: AusNet

7.10. Supporting documents

In additional to the PTRM and relevant parts of the RIN templates submitted as part of this proposal, the following documents are provided in support of this chapter:

- ASG – GAAR 2024-28 – Opex Model – 1 July 2022
- ASG – GAAR Appendix 10 – BIS Oxford Economics' WPI forecast – March 2022 – PUBLIC
- ASG – GAAR Appendix 11 – Internal benchmarking report – 1 July 2022 – PUBLIC

[97] AER 2022, AusNet Services Transmission Determination 2022 to 2027, Attachment 3 rate of return, Final Decision, January, p. 3-9.

- ASG – GAAR Appendix 12 – Priority Services Program business case – 1 July 2022 – PUBLIC
- ASG – GAAR Appendix 13 – Environmental Protection Act step change – 1 July 2022 – PUBLIC
- ASG – GAAR Appendix 13 – Environmental Protection Act step change – 1 July 2022 – CONFIDENTIAL
- ASG – GAAR 2024-28 – EPA cost build up – 1 July 2022 – CONFIDENTIAL
- ASG – GAAR Appendix 25 – Acil Allen Opex partial productivity study – 1 July 2022 – PUBLIC

8. Capital base

8.1. Key points

The capital base has been calculated in accordance with the Rules provisions and the AER's Roll Forward Model (RFM) and Post Tax Revenue Model (version 4) (PTRM).

Our opening capital base for the forthcoming regulatory period includes a transfer of a portion of transmission pipelines, distribution pipelines, service pipes and cathodic protection assets from existing asset classes to a new asset class 'Accelerated Depreciation - Asset Lives' including recalculated remaining lives.

8.2. Chapter structure

The remainder of this chapter is structured:

- Section 8.3 explains the opening capital base as at 1 July 2023;
- Section 8.4 outlines our proposed final year asset adjustments in the RFM;
- Section 8.5 presents information on asset lives and depreciation methodology; and
- Section 8.6 provides information on our proposed forecast depreciation and projected capital base.
- Section 8.7 lists the relevant supporting documents for this chapter.

8.3. Opening capital base as at 1July 2023

In October 2020, the National Energy Legislation Amendment Act 2020 (Vic) was enacted to change the timing of Victorian gas distribution access arrangement periods. The effect of the Act is that the 2018-22 access arrangement period was extended by six months to 30 June 2023. Consequently, we are required to roll forward both the capital base and Tax Asset Base (TAB) by a further six months to 30 June 2023.

Our opening capital base has been calculated in accordance with the AER's standard regulatory approach.

The calculation of the opening capital base as at 1 July 2023, being the start of the forthcoming access arrangement period, involves the following steps:

- Adopt the AER's current determination for the opening capital base, which is $1,562.7 million ($ nominal) as at 1 January 2018;
- Add actual and forecast conforming capital expenditure (net of disposals and customer contributions) for the 2018-23 period;
- Deduct the annual nominal depreciation allowance for the 2018-23 period;
- Apply actual CPI (1 year lagged) so that the opening capital base is expressed in June 2023 prices;
- Adjust for differences between estimated and actual 2017 capital expenditure; and
- Reflect the final year asset adjustments in the RFM, which are explained in section 8.4:

In accordance with the calculations described above, the opening capital base under our proposal as at 1 July 2023 is $1,858.6 million as shown in Table 8.1 below.

Table 8.1: Regulatory Asset Base roll forward to 1 July 2023 ($m nominal)

Regulatory year	2018	2019	2020	2021	2022	Jan – Jun 2023
Opening capital base	1,562.7	1,611.6	1,671.8	1,717.4	1,732.1	1,799.7
Actual / Forecast net capex	98.1	97.0	93.2	97.9	85.1	56.1
Forecast straight line depreciation	-79.4	-70.3	-74.3	-77.2	-84.0	-42.0
Inflation on opening capital base	30.2	33.5	26.6	-6.0	66.6	37.9
Closing capital base	**1,611.6**	**1,671.8**	**1,717.4**	**1,732.1**	**1,799.7**	**1,851.6**
Difference between actual & forecast 2017 net capex						-1.4
Return on difference - Net capex						-0.4
Final year adjustments						8.8
Closing capital base 30 June 2023						**1,858.6**

Source: ASG Roll Forward Model 2018-23

In the sections that follow we outline the process applied to determine the closing capital base as at 30 June 2023.

8.3.1. Actual and forecast net capex, 1 January 2018 to 30 June 2023

The capital base roll forward calculation requires a combination of actual and forecast conforming capital expenditure (net of contributions and disposals), as shown in Table 8.2 below. Our net capex for 2022 and the 6 months to June 2023 are forecasts and we anticipate these placeholders will be updated with actuals in the AER's final determination.

Table 8.2: Net capex, 1 January 2018 to 30 June 2023 ($m nominal)

Regulatory year	2018	2019	2020	2021	2022	Jan – Jun 2023
Gross capex	102.1	102.5	98.7	110.2	102.5	60.4
Less disposals	0.6	-	0.0	0.0	-	-
Less customer contributions	5.9	8.1	7.7	13.7	20.2	5.0
Net capex	95.6	94.4	91.0	96.5	82.3	55.4
Net capex recognised in the capital base[98]	**98.1**	**97.0**	**93.2**	**97.9**	**85.1**	**56.1**

Source: ASG Roll Forward Model 2018-23

Note: Actual expenditure and disposals information reconcile with the nominal values reported in the Annual Regulatory Accounts for regulatory years 2018-21.

8.3.2. Regulatory depreciation, 1 January 2018 to 30 June 2023

Economic depreciation is calculated by determining the nominal depreciation and offsetting the CPI indexation for each asset class. The calculation of each of these elements is set out below.

[98] Net capex recognised in the capital base includes a half-nominal WACC allowance.

8.3.2.1. Forecast straight line depreciation, 1 January 2018 to 30 June 2023

We have sourced the real $2017 straight line depreciation forecasts by asset class from the most recent determination for the current access arrangement period, including annual return on debt updates published by the AER in the 2018-22 PTRM model. These forecasts are input into the AER's standard RFM and adjusted for actual (outturn) inflation. Of note, forecast straight line depreciation in Table 8.3 below reflects the approved standard lives for forecast net capex over the 2018-22 access arrangement period together with straight line depreciation of the opening 2018 capital base. HY2023 forecast straight line depreciation is sourced from our HY2023 Proposal PTRM.[99] The table below shows the calculation.

Table 8.3: Nominal depreciation, 1 January 2018 to 30 June 2023 ($m nominal)

Regulatory year	2018	2019	2020	2021	2022	Jan – Jun 2023
Forecast straight line depreciation ($real 2017)	77.9	67.5	70.3	73.3	76.8	37.6
Actual / Forecast inflation	1.5	2.7	4.0	3.9	7.2	4.4
Nominal depreciation	**79.4**	**70.3**	**74.3**	**77.2**	**84.0**	**42.0**

Source: ASG Roll Forward Model 2018-23

8.3.2.2. Actual and forecast indexation, 1 January 2018 to 30 June 2023

We have applied the definition of CPI outlined below to escalate the capital base for the current access arrangement:

> *CPI is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities from the June quarter in Calendar year t–2 to the June quarter in Calendar year t–1, calculated using the following method:*
>
> *The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the June quarter in Calendar year t–1*
>
> *divided by*
>
> *the ABS CPI All Groups, Weighted Average of Eight Capital Cities for the June quarter in Calendar year t–2*
>
> *minus 1.*[100]

Table 8.4: Actual and forecast inflation, 1 January 2018 to 30 June 2023

Regulatory year	2018	2019	2020	2021	2022	Jan – Jun 2023
1 Year lagged actual CPI	1.93%	2.08%	1.59%	(0.35%)	3.85%	2.10%*

Source: ASG Roll Forward Model 2018-23

** 1 year lagged actual inflation for 6 months to June 2023based on ABS inflation data for the period June 2021 to December 2021.*

For roll forward purposes we have applied the 'all-lagged' inflation approach for both opening capital base indexation and converting real $2017 to $Nominal values for straight line depreciation and net capital expenditures. This is consistent with the roll forward method used in previous access arrangement periods for our distribution capital base.

99 ASG - GAAR HY2023 Distribution PTRM - Public (Updated 31.05.22)
100 AER - Approved AA - AusNet Services 2018-22 - Part B - Reference tariffs & reference policy - final decision revisions marked - November 2017, p. 10.

Table 8.5: Opening capital base indexation, 1 January 2018 to 30 June 2023

Regulatory year	2018	2019	2020	2021	2022	Jan – Jun 2023
Capital base indexation	30.2	33.5	26.6	-6.0	66.6	37.9

Source: ASG Roll Forward Model 2018-23

8.3.2.3. Regulatory depreciation, 1 January 2018 to 30 June 2023

The calculation of economic depreciation (nominal straight line depreciation net of capital base indexation) for the current access arrangement period is shown in the table below.

Table 8.6: Nominal depreciation, 1 January 2018 to 30 June 2023 ($m nominal)

Regulatory year	2018	2019	2020	2021	2022	Jan – Jun 2023
Nominal depreciation	79.4	70.3	74.3	77.2	84.0	42.0
Capital base indexation	-30.2	-33.5	-26.6	6.0	-66.6	-37.9
Regulatory depreciation	**49.2**	**36.8**	**47.6**	**83.2**	**17.4**	**4.2**

Source: ASG Roll Forward Model 2018-23

8.4. Final year asset adjustments

We propose several end of period adjustments in the capital base, most of which relate to our proposed accelerated depreciation as outlined in Chapter 9 (section 9.6). These adjustments involve transferring estimated capital base values from existing asset classes to new asset classes. The adjustments can be summarised as follows;

- Transfer $10.8 million out of 'Transmission pipelines' into a new asset class 'Transmission pipelines – post 1998'.
- Transfer $677.6 million out of 'Distribution pipelines' into a new asset class 'Distribution pipelines – post 1998'.
- Transfer $637.9 million out of 'Service pipes' into a new asset class 'Service pipes – post 1998'.
- Transfer $5.2 million out of 'Cathodic protection' into a new asset class 'Cathodic protection – post 1998'.
- Transfer $61.4 million out of 'Transmission pipelines – post 1998', 'Distribution pipelines – post 1998', 'Service pipes – post 1998' and 'Cathodic protection – post 1998' into a new asset class 'Accelerated depreciation – Long life assets'.
- Transfer $72.7 million out of 'Distribution pipelines – post 1998' and 'Service pipes – post 1998' into a new asset class 'Accelerated depreciation – Future of Gas'.
- Consistent with AASB 16 (Australian Accounting Standard Board) – Leases, starting from 1 April 2019 we have capitalised our existing property leases and included these under a new asset category 'Capitalised Leases – 1 July 2023'. We calculated the nominal closing values as at 30 June 2023 of $8.9 million (and $4.8 million in the TAB) together with their average remaining lives. These calculations are contained in the 'Leases' worksheet of our proposal 2018-23 RFM.

Our proposed end of period adjustments are also summarised in the table below.

Table 8.7 Proposed final year asset adjustments 30 June 2023 ($June 2023)

Asset class	Proposed capital base adjustments ($m)	Remaining life of adjustments (Years)
Transmission pipelines	-10.9	56.9
Distribution pipelines	-677.6	49.5
Service pipes	-637.9	50.4
Cathodic protection	-5.2	50.7
Capitalised leases - 1 July 2023	8.8	6.1
Transmission pipelines - post 1998	10.6	46.9
Distribution pipelines - post 1998	602.8	39.8
Service pipes - post 1998	579.0	40.4
Cathodic protection - post 1998	5.1	40.7
Accelerated depreciation - Long life assets	61.4	5.0
Accelerated depreciation - Future of gas	72.7	5.0
Total	**8.8**	**n/a**

Source: ASG Roll Forward Model (2018-23)

Note: The value transferred out of one asset class and into the corresponding 'post 1998' asset class will not match. The difference between these values reflects adjustments made to reflect the incoming assets shorter asset lives. Further information on this adjustment is explained in Chapter 9 (section 9.6.1).

The consequential adjustments to the opening TAB are outlined in Chapter 11 (section 11.5.1).

8.5. Forecast depreciation and projected asset base

This section discusses the determination of straight line depreciation in the context of setting the regulatory depreciation allowance for the next access arrangement period.

8.5.1. Straight line depreciation

The AER's current approach is to depreciate each new investment equally over the expected life of the asset, typically over 60 years. The straight line approach has the advantage of being easily understood, transparent and capable of being replicated on an ongoing basis. The straight line approach has been applied in previous access arrangement periods on the basis that the economic benefits from the assets will be realised equally over the useful/remaining life of those assets.

However, the rapidly evolving energy market environment has created a high level of uncertainty about the future of the gas network (see Chapter 3) and poses a significant challenge to the current approach to depreciation. It is much less certain that customers in 50 or more years from now will be willing to pay for the costs of today's investments. This uncertainty raises important questions regarding inter-generational cost recovery and whether the current regulatory approach is sustainable. Specifically, there is merit in considering increasing the rate at which capital is recovered from customers by applying accelerated depreciation to assets.

We are proposing to continue to apply the straight line depreciation method over the next access arrangement period. However, as explained in Chapter 3, recognising the uncertainty associated with the future of gas, we are proposing $150 million of accelerated depreciation over the 2024–28 access arrangement period. We have applied this accelerated depreciation without altering the underlying straight line depreciation approach, by doing the following:

- A component of our accelerated depreciation case is achieved by better reflecting the economic lives of several different asset classes – transmission pipelines, distribution pipelines, service pipes and cathodic protection. For those assets that were added to the capital base between 1998 to June 2023, we are proposing to reduce their remaining lives as at 1 July 2023 based on standard lives of 50 years (reduced from 60 years). This translates to accelerated depreciation of $86.3 million over the forthcoming access arrangement period and $24.9 million respectively in the following two access arrangement periods.
- To maintain our total accelerated depreciation proposal at $150 million, we have netted the $86.3 million associated with the shortening of some asset lives off our $150 million, resulting in a further $63.7 million accelerated depreciation to better align the capital recovery profile with the uncertain future of the gas network.

Our proposed approach is a prudent response to the uncertainty that we face, but altering the depreciation profile away from the straight line method would be another option for addressing these issues.

Our proposed accelerated depreciation of the opening capital case is outlined in section 9.6 of Chapter 9.

8.5.2. Projected capital base

The projected capital base for the forthcoming access arrangement period is set out in the table below. The table shows the calculation of the opening asset base and forecast depreciation as described in Chapter 9. In addition, it includes forecast conforming capital expenditure and customer contributions over the forthcoming access arrangement period as described in Chapter 6.

Table 8.8: Projected capital base ($m nominal)

Regulatory year	2023-24	2024-25	2025-26	2026-27	2027-28
Opening capital base	1,858.6	1,919.6	1,987.0	2,047.1	2,083.2
Net capex	117.0	124.0	124.7	109.9	104.1
Straight line depreciation	-110.8	-113.1	-123.2	-134.1	-142.8
Inflation on Opening capital base	54.8	56.6	58.6	60.3	61.4
Closing capital base	**1,919.6**	**1,987.0**	**2,047.1**	**2,083.2**	**2,106.0**

Source: ASG Proposal PTRM (2024-28)

Note: We have forecast zero asset disposals over the 2024 to 2028 access arrangement period.

8.6. Supporting documents

The following documents are provided in support of this chapter:

- ASG – GAAR 2024-28 – Proposal PTRM - 1 July 2022 – PUBLIC
- ASG – GAAR 2024-28 – Roll Forward Model –1 July 2022 – PUBLIC

9. Depreciation

9.1. Key points

- Consistent with the approach used for the current access arrangement, our proposed opening capital base has been depreciated using the year-by-year tracking method.
- Depreciation, including accelerated depreciation, plays a key role in ensuring:
  - Prices for our gas customers remain acceptable in the short and long term.
  - A transition to hydrogen remains viable for the gas network.
  - We have a reasonable opportunity to recover our efficient investment.
- Recognising the uncertainty associated with the future of gas, we are proposing $150 million of accelerated depreciation over the 2024–28 access arrangement period. In coming to this view, we modelled several scenarios before concluding that this amount is reasonable. The rationale for this is discussed in Chapter 3.
- A component of our accelerated depreciation case is achieved by better reflecting the economic lives of several different asset classes – transmission pipelines, distribution pipelines, service pipes and cathodic protection. For those assets that were added to the capital base between 1998 and June 2023, we are proposing to reduce their remaining lives as at 1 July 2023 based on standard lives of 50 years (reduced from 60 years). This translates to accelerated depreciation of $86.3 million over the forthcoming access arrangement period.
- To maintain our total accelerated depreciation proposal at $150 million, we have netted the $86.3 million associated with the shortening of some asset lives off our $150 million, resulting in a further $63.7 million accelerated depreciation to better align the capital recovery profile with the uncertain future of the gas network.

9.2. Chapter structure

The remainder of this chapter is structured as follows:

- Section 9.3 briefly discusses our depreciation methodology.
- Section 9.4 presents our proposed opening capital base depreciation over the 2024-28 access arrangement period.
- Section 9.5 sets out our standard asset lives in the regulatory asset base for the 2024-28 access arrangement period, including our proposed depreciation of forecast capex (as set out in Chapter 6).
- Section 9.6 explains our proposed accelerated depreciation. This covers the two adjustments we have made to the depreciation schedules.
- Section 9.7 presents our proposed depreciation allowance for the 2024-28 access arrangement.
- Section 9.8 lists the supporting documents for this chapter.

9.3. Depreciation methodology

Our proposed methodology for the 2024-28 access arrangement period is consistent with the AER's determination for our current access arrangement period. Our approach can be briefly summarised as:

- Applying straight-line depreciation to assets contained in the opening capital base using the year-by-year tracking approach.
- Apply straight-line depreciation to new assets that will be added to the capital base over the 2024–28 access arrangement period according to their proposed standard lives.

In addition, we are proposing accelerated depreciation of:

- $82.9 million due to the shortening of some asset lives to better reflect their economic life (see section 9.6.1).
- $67.1 million to better align the capital recovery profile with the uncertain future of the gas network established and tested through our future of gas modelling (see section 9.6.2).

Importantly, our accelerated depreciation proposal was tested with our stakeholders and we feel confident that they understand the usefulness of accelerated depreciation as a tool to help control long-term prices and asset stranding risk. While stakeholders have mixed views as to whether using accelerated depreciation is appropriate and who should bear stranding risk, they see value in us maintaining affordability and price stability over the short and long term.[101]

9.4. Opening capital base

Straight-line depreciation of the opening capital base is calculated using the AER year-by-year standard tracking model to calculate depreciation charges for the forthcoming access arrangement period. The depreciation model sets out the values, inputs and calculations used to determine forecast depreciation of the opening capital base at 1 July 2023. The outputs from this model are included as inputs to the Post Tax Revenue Model (Version 2) (PTRM), which is submitted alongside this proposal.

Table 9.1 below contains our proposed straight-line depreciation values for the opening capital base as reflected in the PTRM model. This includes our proposed accelerated depreciation of selected assets in the opening capital base which is discussed in section 9.6 below.

Table 9.9: Proposed opening capital base depreciation 2024-28 ($m June 2023)

Regulatory year	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Opening capital base depreciation	107.7	100.5	99.9	99.2	98.5	**505.8**

Source: ASG Proposal PTRM (2024-28)

9.5. Standard asset lives

Our proposed standard asset lives for new additions in the forthcoming access arrangement period are presented in the table (below). The standard life for equity raising costs reflects the weighted average life of the total capex forecast for the 2024-28 access arrangement period.

Table 9.10: Proposed standard asset lives for new additions to the capital base

Asset class	Standard life (Years)
Supply regulators / Valve stations	50.0
Meters	15.0
SCADA and remote control	15.0
Buildings	40.0
Other - IT	5.0
Other - non IT	5.0

[101] Further information on the future of gas and customer engagement is available in Chapter 3 and Chapter 5 respectively.

Land	n/a
Equity raising costs	37.6

Source: AusNet Services' Roll Forward Model (2018-23)

We are also proposing to change the standard life for long life assets (transmission pipelines, distribution pipelines, service pipes, cathodic protection) from 60 years to 50 years. As part of our proposed forecast final year asset adjustments in the roll forward model, we have, therefore, created six additional asset classes in the PTRM. The rationale for this change is explained in section 9.61 below.

Table 9.11: Additional asset classes

Asset class	Standard life (Years)
Transmission pipelines – post 1998	50.0
Distribution pipelines – post 1998	50.0
Service pipes – post 1998	50.0
Cathodic protection – post 1998	50.0
Accelerated depreciation – Long life assets	5.0
Accelerated depreciation – Future of gas	5.0

Source: AusNet Services' Roll Forward Model (2018-23)

Table 9.4 below sets out the proposed straight-line depreciation for new additions to the capital base in the 2024-28 access arrangement period. These new additions reflect our proposed forecast capex as contained in Chapter 6 of this proposal.

Table 9.12: Proposed depreciation of new assets 2024-28 ($m June 2023)

Regulatory year	2023-24	2024-25	2025-26	2026-27	2027-28	Total
New assets	-	6.3	13.1	20.2	25.1	**64.6**

Source: ASG Services PTRM (2024-28)

9.6. Accelerated depreciation

We are proposing accelerated depreciation of $150 million over the forthcoming access arrangement period. Our proposal was developed in response to:

- The risks demonstrated by modelling we undertook as part of the Future of Gas scenario analysis.
- The likely economic impacts of those scenarios on both our network business and our customers.
- Stakeholder pessimism around the future of our networks and the difficulty of maintaining reasonable prices if networks were to close and customers left the network in significant numbers.
- Strong customer feedback on the importance of maintaining stable and affordable prices over time, particularly for those who cannot readily change their appliances.[102]

[102] A range of price paths reflecting different accelerated depreciation profiles were tested with residential and small business customers, most of whom indicated a preference for price stability over time (rather than lower near-term prices at the expense of higher medium- to long-term prices). Chapter 5 has further information on our customer engagement,

The methodology that we applied to reach $150 million is described in Chapter 3. Based on this work, the accelerated depreciation proposal presented in this proposal is consistent with the depreciation criteria set out in Rule 89 of the NGR, the NGO[103] and the Revenue and Pricing Principles[104].

We are proposing to recover this $150 million of accelerated deprecation through two adjustments to the depreciation schedules:

- $86.3 million of depreciation from shortened asset lives. An engineering review of the technical lives of our assets and asset classes lives revealed that a number of asset classes had been assigned technical lives longer than these assets are remaining in service. This depreciation adjustment is a necessary adjustment to align the economic asset lives with the technical lives. Having economic asset lives that are longer than the technical lives poses an unacceptable risk, as it delays the recovery of the value of assets that are no longer in service. It is important to adjust the depreciation profile for the shorter economic lives of these assets in the next access arrangement period, both to ensure the depreciation schedule complies with the NGR but also to help mitigate the uncertainty about the future of the gas network in Victoria. We also note that this aligns lives with our Victorian peers. The engineering analysis justifying this accelerated depreciation is set out in Appendix 24.
- A financial adjustment of $63.7 million to better align our depreciation schedule with the economic and policy objectives of the regulatory framework, as they are reflected in the depreciation criteria, the NGO and the revenue and pricing principles. Our Future of Gas scenario development and modelling demonstrate that our accelerated depreciation proposal is a prudent strategy for the forthcoming access arrangement period, regardless of the future that faces gas network businesses.

Our proposal was developed after carefully considering several depreciation scenarios and assessing how each one would impact our customers over the short and long term. The scenarios we considered were:

- No accelerated depreciation.
- $130 million accelerated depreciation (consistent with the draft proposal).
- $150 million accelerated depreciation (our proposal).
- $200 million (initial modelling runs).
- Maximum depreciation (approximately $430 million but varying depending on the Future of Gas scenario being modelled).

We consider that $150 million of accelerated depreciation over the forthcoming access arrangement period best balances the long- and short-term price impacts on our customers and the balance between affordability and increasing capital recovery risk for our investors. In doing so, our proposal best contributes to the achievement of the NGO.

The following two subsections set out the specifics of each component of our accelerated depreciation proposal.

9.6.1. Accelerated depreciation of long life assets 1998 to 2023 historical capex capital base

We propose accelerating the depreciation of existing 60 year long life assets (Transmission pipelines, Distribution pipelines, Service pipes, Cathodic protection) from 1998 to 2023 in the opening capital base by reducing the standard life from 60 years to 50 years. Our proposal seeks to transfer the calculated opening value of Long life assets that were added to the capital base between 1998 and 2023 into new asset classes from 1 July 2023 and depreciate them over their shortened remaining lives on average by 10 years. This shorter life is consistent with lives already approved and utilised by MGN in Victoria. We have chosen not to shorten the asset lives of the 1998 opening capital base for two reasons:

1. The 1998 opening capital base for our pipeline and cathodic protection asset classes have a remining life of 13.5 years, so there is limited risk of those assets being stranded; and
2. Given the 13.5 years remaining life, to reduce the asset lives by 10 years would lead to the entire 1998 opening asset base of $322 million being depreciated over 3.5 years which would have resulted in a significant increase in customer prices from 1 July 2023.

Our proposed approach is consistent with clause 89(1)(b) of the NGR, which requires that a depreciation schedule should be designed "so that each asset or group of assets is depreciated over the economic life of that asset or group of assets".

[103] Section 23, NGL.
[104] Section 24, NGL.

The methodology we have used to calculate the accelerated depreciation is a two step process:

1. As outlined in Chapter 8, we propose to transfer an estimated opening total capital base value of $1,331.6 million ($June 2023) out of the existing long-life asset classes into four new asset classes including:
   - 'Transmission pipelines – post 1998'.
   - 'Distribution pipelines – post 1998'.
   - 'Service pipes – post 1998'.
   - 'Cathodic protection – post 1998'.

   Each of these new classes have a standard life of 50 years since we propose to allocate new additions to these classes from 1 July 2023, as reflected in our Proposal PTRM (2024-28). Net of offsets to existing asset classes, this results in an additional $86.3 million of accelerated depreciation over the 2024-28 access arrangement period.

2. An additional asset class was created, 'Accelerated depreciation – Long life assets', into which we transferred the unrecovered depreciation amount for these asset categories, $61.4 million, compared to if they had been depreciated over a 50 year standard life commencing from 1998 through to June 2023. Our model contains the supporting calculations for the opening capital base values and the forgone straight line depreciation of $61.4 million that we propose to recover over the 2024-28 access arrangement period.

The table below shows the proposed straight-line depreciation profile of these assets over the 2024–28 access arrangement period.

Table 9.13: Proposed long life assets accelerated depreciation 2024-28 ($m June 2023)

Regulatory year	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Transmission pipelines – post 1998	0.2	0.2	0.2	0.2	0.2	**1.1**
Distribution pipelines – post 1998	16.1	16.1	16.1	16.1	16.1	**80.7**
Service pipes – post 1998	15.1	15.1	15.1	15.1	15.1	**75.7**
Cathodic protection – post 1998	0.1	0.1	0.1	0.1	0.1	**0.6**
Accelerated depreciation – Long life assets	12.3	12.3	12.3	12.3	12.3	**61.4**
Total	**43.9**	**43.9**	**43.9**	**43.9**	**43.9**	**219.6**
Existing asset classes offset	-26.7	-26.7	-26.7	-26.7	-26.7	**-133.3**
Net accelerated depreciation	**17.3**	**17.3**	**17.3**	**17.3**	**17.3**	**86.3**

Source: ASG Proposal PTRM (2024-28)

The above offsetting depreciation adjustments are contained in our opening capital base depreciation tracking model (up to 30 June 2023).

9.6.2. Accelerated depreciation for the future of gas

As outlined in Chapter 3, $150 million of accelerated depreciation strikes the appropriate balance between ensuring stable prices for our customers and the stranding risks we face given the uncertain future of gas.

As set out in section 9.6.1 above, we are seeking to recover $86.3 million of this through an adjustment to asset lives. As such, we are proposing a net amount of $63.7 million is recovered through this separate adjustment. For clarity, if the amount approved for the asset life varies (or that adjustment is not approved), then this adjustment should be varied by the same amount.

For information on how this approach complies with our obligations under the rules, please refer to section 9.6.3 (below)

Table 9.6: Proposed long Future of Gas accelerated depreciation 2024-287 ($m June 2023)

Regulatory year	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Accelerated depreciation - Future of gas	14.5	14.5	14.5	14.5	14.5	**72.7**
Existing asset classes offset	-1.8	-1.8	-1.8	-1.8	-1.8	**-9.1**
Net accelerated depreciation	**12.7**	**12.7**	**12.7**	**12.7**	**12.7**	**63.7**

Source: ASG Proposal PTRM (2024-28)

9.6.3. How our proposal complies with the NGL and NGR

The NGR require that our proposed depreciation schedule must be consistent with the criteria in Rule 89 of the NGR, which states[105]:

(1) The depreciation schedule should be designed:

(a) so that reference tariffs will vary, over time, in a way that promotes efficient growth in the market for reference services; and

(b) so that each asset or group of assets is depreciated over the economic life of that asset or group of assets; and

(c) so as to allow, as far as reasonably practicable, for adjustment reflecting changes in the expected economic life of a particular asset, or a particular group of assets; and

(d) so that (subject to the rules about capital redundancy), an asset is depreciated only once (i.e. that the amount by which the asset is depreciated over its economic life does not exceed the value of the asset at the time of its inclusion in the capital base (adjusted, if the accounting method approved by the AER permits, for inflation)); and

(e) so as to allow for the service provider's reasonable needs for cash flow to meet financing, non-capital and other costs.

For the reasons explained below, we consider our proposal for accelerated depreciation and the depreciation schedule that gives effect to it are consistent with the depreciation criteria and the revenue and pricing principles, and are in the long-term interests of consumers.

9.6.3.1. Rule 89(1)(a)

Rule 89(1)(a) states that a depreciation schedule should be designed so that reference tariffs will vary, over the time, in a way that promotes efficient growth in the market for reference services. The NGR leaves it to service providers to design and propose the schedules that it considers is consistent with this objective and the remaining depreciation criteria. Rule 89(2) clarifies that financial deferral of an amount of depreciation that would otherwise be expected under standard assumptions may be compliant with subrule (1)(a).

These subrules indicate that the NGR expressly contemplates situations arising which warrant varying the depreciation profile due to the market circumstances. Rule 89(2) assures the service provider that it is not bound to mechanistically apply a depreciation schedule if doing so would prevent it from achieving economies of scale because the tariffs are too high and/or there are insufficient customers to meet the cost of the depreciation in the early years of the network. The subrule explicitly acknowledges that deferring depreciation until a time that network usage is better able to match the depreciation costs increases the likelihood that the market for reference services will grow, and thus better achieves the first depreciation criterion. Although subrule (2) is limited to deferred depreciation, it follows that there may be a range of depreciation profiles that achieve compliance with Rule 89(1)(a).

In the case of this access arrangement proposal, Rule 89(1)(a) is of limited relevance because it is directed to setting reference tariffs in a way that grows a market, rather than offering guidance about how depreciation should be

[105] NGR 89.

managed where the network is in decline (or there is a material risk that it will begin to decline). In the absence of any specific instructions in the NGR, we have been guided in the development of our depreciation proposal and design of the schedule by the NGO and the revenue and pricing principles.

If a network enters run-down mode, the number of connected customers begins to decline and ultimately approaches zero. Consequently, the average cost borne by those customers remain who increases, unless the service provider reduces its operating expenditure and/or its capital base (which when faced with high fixed costs is not possible). The magnitude and steepness of these price impacts can be moderated if the service provider aligns the depreciation trajectory and network usage by setting depreciation at higher level while the network has many customers and reducing it as customers leave. This manages the cost impost on the remaining customers and provides the service provider with a reasonable opportunity to recover its network investment.

Our proposal for $150 million of accelerated depreciation in the forthcoming access arrangement period is the inverse of the scenario expressly contemplated by Rule 89(2), in that it aligns depreciation with the risk that network usage may start to decline during the period or near future. In calculating this figure and the trajectory, we have considered which depreciation schedule best promotes the efficient operation of our network and the short-term and long-term price impacts on our customers.[106] We have also had regard to the principle that a service provider should be provided with a reasonable opportunity to recover at least the efficient costs it incurs in providing reference services, which includes investment in network assets.[107]

Our depreciation proposal also promotes economic efficiency in that it enables reference tariffs to be set at levels that continue to provide a commercial return commensurate with the risks of continuing to operate at a time when the future of gas is uncertain.[108] Relatedly, it provides appropriate incentives to guard against under-investment is a network whose value is declining.[109]

9.6.3.2. Rule 89(1)(b)

In accordance with rule 89(1)(b), the depreciation schedule should be designed so that each asset or group of assets is depreciated over the economic life of that asset or group of assets.

We conducted a review of our asset lives that shows few assets older than 60 years and a large drop off in the number of assets aged over 50 years. As demonstrated in Appendix 24, a standard life of 60 years is in excess of how long our assets actually last and this shows that we continue to have depreciation of assets that no longer remain in service on our network. In accordance with Rule 89(1)(b) we are proposing a corresponding adjustment to the economic lives of these assets and this represents an $82.9 million of accelerated depreciation.

It may at this time also be possible to argue that the economic lives of our assets are even shorter than this technical life of 50 years and that a further adjustment is warranted. If for example, the network was to be fully decommissioned by 2060, then an even shorter economic life for new assets of 38 years would be justified. However, our view is that a further adjustment to asset lives is not the best course of action at this time. Presently, the economic lives of all network assets are uncertain, and we expect this to persist in the medium term until the future of gas networks is resolved. If the gas networks successfully transition to a hydrogen future and the majority of pipelines remain in service, then 50 years would remain an accurate estimate of economic life. It is equally possible that the economic life of our assets is significantly curtailed if parts (or the totality) of our network is decommissioned. We consider that making an explicit adjustment to economic lives at this time (other than to reflect revised technical lives) risks embedding an assumption into the AER's decision that subsequently proves to be erroneous.[110]

The better approach, and the approach that best achieves the NGO, is to make a financial adjustment to accelerate depreciation of a portion of the asset base but leave the economic asset lives of the assets unchanged (beyond accommodating the reduced technical life). This maximises the likelihood that our assets and groups of assets are depreciated over the actual economic life, as required by Rule 89(1)(b).

106 NGO, section 23, NGL.
107 Section 24(2), NGL.
108 Section 24(5), NGL.
109 Section 24(6), NGL.
110 However, if the AER does not accept that our proposed approach is appropriate to account for the uncertain future, then we would likely propose shortening asset lives further our revised proposal.

9.6.3.3. Rule 89(1)(c)

In the preceding section we outlined how our technical review resulted in a corresponding change to the economic lives of certain assets and asset classes. Rule 89(1)(c) encourages depreciation schedules to be designed to allow such changes to be accommodated, as far as reasonably practicable.

We have designed our proposed depreciation schedule to give effect to the changes in economic asset lives from the start of the new access arrangement period. This approach is most appropriate because it we have used the opportunities that our stakeholder and customer consultation processes have provided to obtain feedback on our proposal. Further, it is less complex to apply new asset lives from the start of a new access arrangement period than to seek to do it in mid-way through a period.

Our Future of Gas modelling demonstrates that if we delay implementing accelerated depreciation we may lose the opportunity to mitigate future price impacts on our customers. As such, we do not think the ability to make mid-period adjustments to the depreciation schedules justifies delaying action. Nevertheless, our proposed schedule does allow for mid-period adjustment in the event of further changes in economic asset lives, as required by Rule 89(1)(c).

9.6.3.4. Rule 89(1)(d)

Under Rule 89(1)(d), a depreciation schedule should be designed so that an asset is depreciated only once. This requires that the amount by which the asset is depreciated over its economic life does not exceed the value of the asset at the time of its inclusion in the capital base.

We have modelled the accelerated depreciation as an adjustment within the AER's standard depreciation model. Using this model ensures that our proposed adjustment is properly calculated and our accelerated depreciation proposal does not allow us to over-recover. Consequently, any revenue we receive in the forthcoming regulatory period as a result of this aspect of our proposal is forgone in future access arrangement periods.

9.6.3.5. Rule 89(1)(e)

The final depreciation criterion (Rule 89(1)(e)) requires that the depreciation schedule should be designed so as to allow for the service provider's reasonable needs for cash flow to meet financing, non-capital and other costs.

We acknowledge a concern raised by stakeholders that a gas distributions business, which depreciates its capital base well below the value dictated by the economic lives of its assets, risks creating a mismatch between its cash flow and expenditure needs. This could result in more assets being due for replacement than the revenue being provided from a depleted capital base, leading to a cashflow shortage for the business. While we acknowledge this is a theoretical concern, we do not consider it a material issue at this time, because:

- A significant portion ($86.3 million) of our proposal relates to ensuring better aligning between the economic life of our assets with their technical life. This is reducing a capital base that is actually higher than warranted, as opposed to artificially reducing it.
- We are proposing this accelerated depreciation because the uncertainty of the gas network. Specifically, a substantial number of assets may need to be decommissioned in the future, which means the capital base would be unmatched to the asset base and too high. If we wait until we have certainty before we begin to apply accelerated depreciation, there is likely to be a significant mismatch between the capital base and the asset base and this would exacerbate the adverse price impacts for customers. It is more prudent to begin a strategy of accelerated depreciation now to minimise any future mismatch.
- Our proposal will see our capital base decline on a per customer basis, but in nominal terms it will rise from $1,861.3 million to $2,103.3 million over the forthcoming access arrangement period. Our proposal for accelerated depreciation represents less than 8% of the existing capital base and does not leave our capital base at an unreasonably low level. The capital base will provide a return on and return of capital of ~$825 million over the 2024-28 access arrangement period, which is significant cash flow from which to fund necessary capital expenditure. Significant future reductions in the capital base would be necessary to cause cashflow problems for our business.

9.7. Forecast depreciation allowance

Based on the depreciation methodology described above, our total forecast economic depreciation for the forthcoming access arrangement period is $303.1 million ($June 2023l). Depreciation amounts are presented in the table below.

Table 9.7: Long life assets accelerated depreciation 2024-28 ($m June 2023)

Regulatory year	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Existing assets	77.7	70.5	69.9	69.2	68.5	**355.8**
Accelerated depreciation – Asset lives	17.3	17.3	17.3	17.3	17.3	**86.3**
Accelerated depreciation - FoG	12.7	12.7	12.7	12.7	12.7	**63.7**
New assets	-	6.3	13.1	20.2	25.1	**64.6**
Less indexation on opening capital base	-53.2	-53.4	-53.7	-53.6	-53.1	**-267.1**
Net depreciation allowance	**54.4**	**53.4**	**59.3**	**65.8**	**70.5**	**303.4**

Source: AusNet Services PTRM Model (2024-28)

9.8. Supporting documents

The following documents are provided in support of this chapter:

- ASG – GAAR 2024-28 – Depreciation tracking Model – 1 July 2022 – PUBLIC
- ASG – GAAR 2024-28 Accelerated Depreciation Calculation Model – 1 July 2022 – PUBLIC
- ASG – GAAR - Appendix 24 – Analysis of Standard Asset Lives for Accelerated Depreciation – 1 July 2022 – CONFIDENTIAL

The Future of Gas Models (as detailed in Chapter 3) are also relevant for this chapter.

10. Rate of return

10.1. Key points

- In December 2018, the AER published its Rate of Return Instrument[111] and an accompanying explanatory statement[112], which sets out the key parameter values and the method that should be applied in estimating the rate of return. The AER is currently updating the 2018 Rate of Return Instrument, and expects to publish the 2022 Rate of Return Instrument in December 2022.
- The 2022 Rate of Return Instrument will apply to this access arrangement period. For the purpose of this proposal, however, we have adopted the 2018 Rate of Return Instrument to determine placeholder values. These placeholder values will be updated during the AER's review process to reflect the requirements of the 2022 Rate of Return Instrument.
- In addition, we have applied the AER's proposed interim measures to address the implementation issues arising from the 6 month extension to the current access arrangement period. This comprises the application of the 2018 Rate of Return Instrument and a modification to the trailing average cost of debt.
- Our debt and equity raising costs have been estimated in accordance with the AER's current practice.
- A gamma value of 0.585 has been adopted in accordance with the 2018 Rate of Return instrument.
- Our placeholder inflation forecast is 2.95% for the access arrangement period commencing 1 July 2023 based on the AER's approach to estimating forecast inflation.

10.2. Chapter structure

The structure of the remainder of this chapter is:

- Section 10.3 provides a brief commentary on the AER's Rate of Return Instrument.
- Sections 10.4 and 10.5 set out our allowed cost of equity and debt for the 2024–28 access arrangement period.
- Section 10.6 outlines our proposed approach to gearing.
- Section 10.7 summarises our estimated weighted average cost of capital (WACC).
- Section 10.8 explains our estimated equity raising and debt raising costs.
- Section 10.9 recaps the role of imputation credits under the post-tax revenue model, and notes the value of gamma adopted for the 2024–28 access arrangement period.
- Section 10.10 explains our forecast inflation.
- Section 10.11 lists the supporting documents for this chapter.

10.3. Rate of Return Instrument

The AER published its Rate of Return Instrument and an accompanying explanatory statement in December 2018.[113] In accordance with the Rules, the 2018 Rate of Return Instrument is currently being reviewed by the AER and will be replaced with the 2022 Rate of Return Instrument, which will apply to the forthcoming access arrangement period.

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[111] AER, Rate of return instrument, December 2018, available at: https://www.aer.gov.au/system/files/2018%20Rate%20of%20Return%20Instrument%20%28Version%201.02%29_1.pdf (accessed 26/05/2022).
[112] AER, Rate of return instrument – Explanatory Statement, December 2018, available at: https://www.aer.gov.au/system/files/Rate%20of%20Return%20Instrument%20-%20Explanatory%20Statement.pdf (accessed 26/05/2022).
[113] Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rate-of-return-instrument-2018 (accessed 26/05/2022).

The 2018 Rate of Return Instrument is referred to in the remainder of this chapter to establish placeholder values that will be updated once the 2022 Rate of Return Instrument is finalised in December 2022.

The AER's 2018 Rate of Return Instrument maintains its long-standing regulatory approach of determining a nominal vanilla weighted average return on equity and debt, weighted by the gearing ratio.[114] The AER's Rate of Return Instrument therefore defines the allowed rate of return as follows:

- $kt = (1\text{-G}) \text{ x } ke + \text{ktd x G}$

Where:

- kt is the rate of return in regulatory year t;
- ke is the allowed return on equity for the regulatory period and is calculated in accordance with clause 4 of the instrument;
- ktd is the allowed return on debt for the regulatory year t, and is calculated in accordance with clause 9 of the instrument; and
- G is the gearing ratio and is set at a value of 0.6.

This chapter applies this formula to calculate the allowed rate of return for each regulatory year of the 2024–28 access arrangement period.

10.4. Return on equity

The AER's 2018 explanatory statement adopts the Sharpe-Lintner CAPM (SLCAPM) to calculate the return on equity. Within the SLCAPM formula, the AER sets fixed values for the market risk premium and equity beta and establishes a formula for calculating the risk free rate. Clause 4 of the AER's Rate of Return Instrument defines the return on equity as follows:

- ke = kf + β x MRP

Where:

- kf is the allowed risk free rate of return expressed as an effective annual rate;
- β is the allowed equity beta and is set to a value of 0.6; and
- MRP is the allowed market risk premium and is set to a value of 6.1% per annum.

As the values of the equity beta and market risk premium have been set by the AER's 2018 Rate of Return Instrument, we have adopted these values for the purpose of this proposal in accordance with the requirements of the Rules.

The 2018 Rate of Return Instrument requires us to estimate the risk free rate using a formula based on yields on 10-year Commonwealth Government Securities (CGS). The formula requires the risk free rate averaging period to be:

- over a period of between 20 and 60 business days;
- start no earlier than 7 months prior to the commencement of the regulatory period; and
- finish no later than 3 months prior to the commencement of the regulatory period.[115]

In accordance with the 2018 Rate of Return Instrument, we have nominated an averaging period in a confidential letter to the AER. For the purpose of this proposal, it is only possible to provide an estimate of the risk free rate that will apply. The AER will update the risk free rate and the resulting cost of equity in its draft and final decisions. In this proposal, as a placeholder value, we have adopted a risk free rate estimate of 2.79% as shown in Table 10.1 below.

In accordance with the AER's 2018 Rate of Return Instrument, our estimated cost of equity for the purpose of this proposal is 6.45%, as presented in the table below. As already noted, these values will be updated to reflect the requirements of the 2022 Rate of Return Instrument and the agreed averaging period for the risk free rate.

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[114] Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rate-of-return-instrument-2018 (accessed 26/05/2022).
[115] AER, Rate of Return Instrument, clause 8.

Table 10.14 Proposed cost of equity parameters

Asset class	Proposed value	Basis of parameter value
Risk fee rate (nominal)	2.79%	This is a placeholder value reflecting the yield on ten year Australian Commonwealth bonds (sourced from early April 2022 RBA data[116]) that we expect will be updated by the AER. The risk free rate for the AER's final determination will be measured over the nominated periods selected in accordance with clause 8 of the AER's 2018 Rate of Return Instrument.
Equity beta	0.6	This value is consistent with clause 4(b) of the AER's 2018 Rate of Return Instrument.
Market risk premium	6.1%	This value is consistent with clause 4(c) of the AER's 2018 Rate of Return Instrument.
Cost of equity	6.45%	The cost of equity is estimated in accordance with the SLCAPM, as specified in clause 4 of the AER's 2018 Rate of Return Instrument.

Source: ASG Proposal PTRM 2024-28

10.5. Cost of debt

The AER approach to estimating the cost of debt comprises the following key elements:

- A benchmarking approach, based on debt yield data from third party data providers and benchmarks for term of debt and credit rating.
- A 10-year trailing average approach with an annual update.
- A 10-year transition to the 10-year trailing average approach, noting that where a transition has commenced in a previous determination, the AER will continue that transition.

In the AER's final decision for our 2018-22 period, the AER adopted an 'on-the-day' approach for the first regulatory year and commenced a 10-year transition to a trailing average approach, which operates as follows:

- For 2018, the estimated cost of debt reflected the prevailing market rates near the commencement of the 2018–22 regulatory period.
- For each subsequent year, 10% of the return on debt is updated to reflect the prevailing market conditions in that year.

In accordance with the AER's 2018 Rate of Return Instrument, this transitional approach has been maintained for the forthcoming access arrangement period. The only complicating factor relates to the six month extension to the current access arrangement period, which affects the operation of the transition to the trailing average. Following discussions with the AER, we have adopted a simple adjustment to the transitional approach to accommodate the six month extension.

For the purpose of this proposal, the average placeholder portfolio cost of debt is 4.01% over the 2024-28 access arrangement period, incorporating a prevailing cost of debt placeholder of 4.11%. The prevailing cost of debt placeholder of 4.11% reflects the outcome for the six month extension period (1 Jan to 30 June 2023). The return on debt for the 2024-28 access arrangement period will be updated in accordance with AER's 2022 Rate of Return Instrument.

The table below shows the estimated cost of debt over the 2024-28 access arrangement period, in accordance with the AER's trailing average approach.

[116] https://www.rba.gov.au/chart-pack/interest-rates.html#6 (accessed 06/04/2022).

Table 10.15: Estimated benchmark cost of debt

Regulatory year	2023-24	2024-25	2025-26	2026-27	2027-28
Nominal pre-tax return on debt	4.20%	4.10%	4.01%	3.92%	3.83%

Source: ASG Proposal PTRM 2024-28

10.6. Gearing

The benchmark gearing (or capital structure) is used to weight the allowed return on debt and equity to derive the overall allowed rate of return.

In its regulatory determinations for gas and electricity networks, the AER has consistently applied a benchmark efficient level of gearing of 60%. For the purpose of this proposal, we have also adopted a benchmark gearing level of 60%.

10.7. Nominal vanilla WACC

The table below summarises the calculation of the nominal vanilla WACC or the 'allowed rate of return', in accordance with clause 3 of the AER's 2018 Rate of Return Instrument. The table shows that the application of the AER's approach would result in a WACC of 5.10% for 2023-24, reducing to 4.88% by 2027-28.

Table 10.16: Estimated nominal vanilla WACC

Regulatory year	2023-24	2024-25	2025-26	2026-27	2027-28
Return on equity	6.45%	6.45%	6.45%	6.45%	6.45%
Nominal pre-tax return on debt	4.20%	4.10%	4.01%	3.92%	3.83%
Gearing	60%	60%	60%	60%	60%
Nominal vanilla WACC	**5.10%**	**5.04%**	**4.99%**	**4.93%**	**4.88%**

Source: ASG Proposal PTRM 2024-28

The allowed rate of return will be updated in the AER's draft and final decisions and then annually to reflect movements in the cost of debt, in accordance with the 2022 Rate of Return Instrument.

10.8. Debt and Equity raising costs

Debt raising costs form part of our opex allowance and are explained in Chapter 7 of this proposal.

Equity raising costs are the transaction costs incurred when network service providers raise new equity in order to fund capital investment. Accordingly, the AER provides a benchmark allowance to reflect the efficient costs of raising equity, if equity raising is required to maintain the benchmark gearing of 60%.

Our equity raising costs are derived from the PTRM and the AER's benchmarking approach, which includes a distribution rate of 0.9, consistent with the Rate of Return Instrument. Our modelling indicates that under the AER's approach no external equity injection is required to maintain the benchmark capital structure over the 2024-28 regulatory period.

10.9. Imputation credit value (Gamma)

Under the Australian imputation tax system, investors receive imputation credits for tax paid at the company level. For eligible shareholders, imputation credits offset their Australian income tax liabilities. The AER takes account of the value of imputation credits (known as gamma or 'γ') to recognise that imputation credits benefit equity holders, in addition to any dividends or capital gains they receive.

As the regulatory framework applies a post-tax WACC, the value of imputation credits is not a WACC parameter. Instead, the value of imputation credits is a direct input into the calculation of a network service provider's benchmark tax allowance. In accordance with the AER's 2018 Rate of Return Instrument, we have adopted a placeholder value for imputation credits of 0.585.

The calculation of our benchmark tax allowance for the 2024-28 access arrangement period is provided in Chapter 11.

10.10. Forecast inflation

Our forecast inflation is 2.95% for the 2024-28 access arrangement period, which will be updated in the AER's draft and final decisions. This forecast is based on the AER's approach to estimating the average annual rate of inflation expected over a five year period, which reflects:

- A target inflation horizon from that matches the access arrangement period, which is five years.
- Applying a linear glide-path from the RBA's forecasts of inflation for years 1 and 2 to the mid-point of the inflation target band (2.5 per cent) in year 5.

We expect our forecast inflation to be updated during the review process to account for new information provided in the RBA's latest Statement of Monetary Policy.

10.11. Supporting documents

The following document is provided in support of this chapter:

- ASG – GAAR – Appendix 14 – Rate of Return Averaging periods – 1 July 2022 – CONFIDENTIAL

11. Corporate tax allowance

11.1. Key points

- This chapter explains the key changes which affect the final calculation of the tax allowance building block post 30 June 2023.
- We have maintained the weighted average remaining life approach for depreciation of the opening Tax Asset Base (TAB) commencing from 1 January 2023.
- As per the AER's revised tax approach, we explain the basis of our forecast of immediately deductible expenditure for the period 1 July 2023 to 30 June 2028.

11.2. Chapter structure

The remainder of this chapter is structured as follows:

- Section 11.3 discusses the AER's Final Report on its review of its regulatory approach to setting the tax allowance.
- Section 11.4 explains the method for calculating the tax allowance.
- Section 11.5 calculates the opening TAB as at 1 July 2023.
- Section 11.6 presents the standard tax lives and remaining lives which are used to calculate tax depreciation.
- Section 11.7 presents our forecast of immediately deductible expenditure for the 2024–28 access arrangement period.
- Section 11.8 sets out the proposed tax allowance.

11.3. AER review of the tax allowance

The corporate income tax allowance is an input into our revenue requirement, allowing us to recover an estimate of the corporate tax liability an efficient distributor would incur as a result of the provision of reference services.

The AER has undertaken a review of the approach for assessing the regulatory tax allowance for service providers following consultation with the ATO on actual tax payments made by businesses and the reasons for some of the differences.

The AER published Version 1 of the Gas Distribution Post Tax Revenue Model (PTRM) in April 2020 which implements the relevant findings from the regulatory tax review undertaken in 2018[117]. Specifically, the AER made two changes which affect the calculation of tax depreciation in the PTRM:

- Immediate expensing of capex – allows for inputs of certain capex to be immediately expensed when estimating the benchmark tax expense.
- Diminishing value depreciation method – applies diminishing value method for tax depreciation purposes to all new depreciable assets except for capex associated with in-house software, equity raising costs and buildings.

The above changes take effect from 1 July 2023 for the Victorian Gas Distribution businesses. We have populated the latest version of the PTRM (Version 2[118]) with the data presented in this access arrangement proposal.

[117] AER, Final report: Review of regulatory tax approach, December 2018, p. 20.
[118] Version 2 (published in April 2021) applies the AER's inflation review final position for calculation of expected inflation.

11.4. Methodology

11.4.1. Overview

The AER's PTRM calculates a DNSP's tax allowance (or the tax building block) by:

1. Deducting tax expenses (opex, interest payments on debt and total tax depreciation for all assets) from required revenue (including income from customer contributions) to arrive at the DNSP's taxable income; and
2. Multiplying taxable income by the corporate income tax rate, then multiplying the result by one minus the utilisation of imputation credits (gamma).

This calculation is represented by the following equation contained in rule 87A(1) of the NGR:

$ETC_t = (ETI_t \times r_t)\ (1 - \gamma)$

where:

- ETI_t is an estimate of the taxable income for that regulatory year that would be earned by a benchmark efficient entity as a result of the provision of reference services if such an entity, rather than the service provider, operated the business of the service provider;
- r_t is the expected statutory income tax rate for that regulatory year as determined by the AER; and
- γ is the value of imputation credits.

11.4.2. Inputs to the calculation of the tax allowance

The method for calculating our tax allowance for the 2024-28 access arrangement period requires the following inputs:

- Opening TAB as at 1 July 2023.
- Remaining tax lives.
- Standard tax lives.
- The company income tax rate.
- The value of gamma.
- Any accumulated tax losses as at 1 July 2023.
- A forecast of immediate expensed (for tax purposes) capex for the 2024–28 access arrangement period.

Each of these inputs is discussed in the following sections.

11.5. Opening TAB as at 1 July 2023

The following table shows the roll forward of the TAB using actual and forecast gross capex (net of asset disposals) and tax depreciation. Our capex for 2022 and the 6 months to June 2023 are forecasts and will be updated with actual where available.

Table 11.1: TAB roll forward 1 July 2023 ($m nominal)

Regulatory year	2018	2019	2020	2021	2022	Jan – Jun 2023
Opening TAB	707.3	763.5	815.6	868.7	941.0	1,000.7
Gross capex less asset disposals	101.5	102.5	98.7	110.2	102.4	63.6
Less tax depreciation	-45.4	-50.3	-45.7	-37.9	-42.7	-22.5
Final year asset adjustments						4.8
Closing TAB 30 June 2023	**763.5**	**815.6**	**868.7**	**941.0**	**1,000.7**	**1,046.6**

Source: ASG Roll Forward Model (2018-23)

For the TAB roll forward from 1 July 2023, we have continued using the WARL approach for the opening TAB and consequently the straight-line depreciation calculations are based on the remaining lives contained in the PTRM opening TAB inputs (and as detailed below in section 11.5.3).

11.5.1. Final year asset adjustments

Our final year asset adjustments in the TAB comprise two elements including:

- Transfer of total opening TAB value of $894.9 million from existing asset classes to new asset classes that represents the residual value of post January 1998 tax assets and their remaining tax lives as at 1 July 2023. Related adjustments to the capital case are described in Chapter 8, section 8.4. The opening TAB values transferred to each new asset class includes our forecast tax capex for 2022 and the 6 months to June 2023.
- Establish the opening tax value of capitalised leases and their average remaining tax lives based on a tax asset roll forward calculation.

Our proposed TAB adjustments are shown in the table below.

Table 11.2: Proposed final year TAB adjustments

Asset class	Proposed TAB adjustments ($m)	Remaining life of adjustments to TAB (Years)
Capitalised leases – 1 July 2023	4.8	6.2
Transmission Pipelines	-20.94	
Distribution Pipelines	-451.12	
Service Pipes	-416.56	
Cathodic Protection	-6.29	
Transmission pipelines - post 1998	20.94	26.3
Distribution pipelines - post 1998	451.12	33.6
Service pipes - post 1998	416.56	36.7
Cathodic protection - post 1998	6.29	20.7
Total	**4.8**	**n/a**

Source: ASG Roll Forward Model (2018-23)

11.5.2. Remaining tax lives

The remaining lives for assets contained in the 1 July 2023 opening TAB, including final year asset adjustments (outlined above), are presented below.

Table 11.3: Remaining tax lives

Asset class	Remaining life (Years)
Transmission pipelines	26.3
Distribution pipelines	33.6
Service pipes	36.7
Cathodic protection	20.7
Supply regulators/Valve stations	30.9
Meters	12.0
SCADA and remote control	8.0
Other - IT	2.9
Other - non IT	3.4
Buildings	12.2
Capitalised leases – 1 July 2023	6.2
Transmission pipelines – post 1998	26.3
Distribution pipelines – post 1998	33.6
Service pipes – post 1998	36.7
Cathodic protection – post 1998	20.7
Equity raising costs	3.8

Source: ASG Roll Forward Model (2018-23)

11.6. Standard tax lives

At the commencement of the 2018–22 access arrangement period we adopted the standard tax lives set out in ATO Tax Ruling 2015-2 (TR 2015/2) to assign standard lives to each tax asset class. The AER approved the standard tax lives as part of our transition away from maintaining tax depreciation schedules that used ESC tax categories and a combination of the diminishing value approach up until 2012 and straight line tax depreciation for the 2013-17 access arrangement period. This process resulted in the standard tax lives shown in the table below.

Table 11.4: Standard tax lives for 2018–22 access arrangement period

Asset class	Standard tax life (Years)
Transmission pipelines	50.0
Distribution pipelines	50.0

Service pipes	50.0
Cathodic protection	50.0
Supply regulators/Valve stations	40.0
Meters	15.0
SCADA and remote control	10.0
Other - IT	4.0
Other - non IT	4.0
Buildings	35.0
Land	n/a

Source: ASG Roll Forward Model (2018-23)

11.6.1. Proposed standard lives

For the forthcoming access arrangement period, we have adopted the same standard tax lives set out in Table 11.4 above with the exception of a 20 year standard tax life that is applied to the following asset classes as part of our proposal:

- 'Supply regulators / Valve stations'.
- 'Transmission pipelines – post 1998'.
- 'Distribution pipelines – post 1998'.
- 'Service pipes – post 1998'.
- 'Cathodic protection – post 1998'.

The AER foreshadowed the adoption of a 20 year standard tax life commencing from 1 July 2023 for our three pipeline asset classes and the 'Cathodic protection' asset class as part of implementing its findings from the 2018 tax review. We have therefore applied the 20 year tax life to our proposed new asset classes (shown in Table 11.5 below) that are associated with our final year adjustments in the capital base (as outlined in section 8.4 of Chapter 8) and existing class 'Supply regulators / Valve stations'. Our proposed standard tax lives for new additions in the forthcoming access arrangement period are presented in Table 11.5 below, including the diminishing value rates that will apply.

Table 11.5: Proposed standard tax lives for new additions to the capital base for the 2024–28 access arrangement

Asset class	Standard tax life (Years)	DV Rate (200%)
Supply regulators / Valve stations	20.0	10.0%
Meters	15.0	13.3%
SCADA and remote control	10.0	20.0%
Buildings	35.0	5.7%
Other - IT	4.0	50.0%
Other - non IT	4.0	50.0%
Land	n/a	n/a
Transmission pipelines – post 1998	20.0	10.0%
Distribution pipelines – post 1998	20.0	10.0%

Service pipes – post 1998	20.0	10.0%
Cathodic protection – post 1998	20.0	10.0%

Source: ASG PTRM (2022-28)

11.7. Forecast of immediately deductable expenditure

The table below contains our forecast of immediate deductible capital expenditure for the 2024–28 access arrangement period as provided in the PTRM that is submitted as part of this proposal. For tax purposes, all capitalised overheads, including both labour and non-labour components, are treated as immediately deductible capital expenditure. There is no capital replacement included in our forecast of immediately deductible capital expenditure in Table 11.6 below, consistent with our historical income tax returns for the gas distribution business.

Table 11.6: Forecast immediately deductible expenditure 1 July 2023 to 30 June 2028 ($m Jun $2023)

Regulatory year	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Supply regulators / Valve stations	0.2	0.2	0.1	0.1	0.2	**0.9**
Meters	0.4	0.4	0.5	0.4	0.4	**2.2**
SCADA and remote control	0.0	0.0	0.0	0.0	0.0	**0.1**
Other - IT	0.4	0.4	0.4	0.4	0.4	**1.9**
Other - non IT	0.0	0.0	0.0	0.0	0.0	**0.1**
Transmission pipelines – post 1998	0.0	0.0	0.1	0.0	0.0	**0.2**
Distribution pipelines – post 1998	0.9	0.8	0.7	0.8	0.8	**4.0**
Service pipes – post 1998	1.1	1.1	1.1	1.1	1.1	**5.5**
Cathodic protection – post 1998	0.0	0.0	0.0	0.0	0.0	**0.1**
Total	**3.0**	**3.0**	**3.0**	**3.0**	**2.9**	**14.9**

Source: ASG Proposal PTRM 2024-28

We confirm that we do not intend to change our current tax policy of immediately expensing capital expenditure for our gas distribution business.

11.8. Proposed tax allowance

The table below presents our forecast TAB roll forward for the forthcoming access arrangement period. We observe that the tax depreciation charge increases substantially compared to the current period, mainly due to immediately deductible expenditure and diminishing value approach applied to new additions.

Table 11.7: Tax Asset Base roll forward to 30 June 2028 ($m nominal)

Regulatory year	2023-24	2024-25	2025-26	2026-27	2027-28
Opening TAB	1,046.6	1,124.3	1,189.2	1,239.3	1,271.5
Plus capex, net of disposals	113.9	120.7	121.3	110.7	102.4
Plus capital contributions	8.3	8.7	9.1	9.3	9.4
Less tax depreciation	-44.6	-64.5	-80.3	-87.8	-92.2
Closing TAB	**1,124.3**	**1,189.2**	**1,239.3**	**1,271.5**	**1,291.1**

Source: ASG Proposal PTRM 2024-28

We have assumed a company income tax rate of 30% for the 2024–28. As already noted, we have used 58.5% for the value of gamma in accordance with the AER's 2018 rate of return instrument.

Consistent with information contained in the current period decision PTRM (2018-22), our submitted HY2023 PTRM[119] and our 2024-28 Proposal PTRM, we confirm that there are no accumulated tax losses as at 1 July 2023 nor any expected carried forward losses as at 30 June 2028. Our forecast of the tax allowance for the 2024–28 access arrangement period is outlined in the table below.

Table 11.8: Proposed tax allowance 1 July 2024 to 30 June 2028 ($m nominal)

Regulatory year	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Tax payable	23.2	17.2	15.4	16.5	18.0	**90.3**
Imputation credits	-13.6	-10.1	-9.0	-9.6	-10.5	**-52.8**
Tax allowance	**9.6**	**7.2**	**6.4**	**6.8**	**7.5**	**37.5**

Source: ASG Proposal PTRM 2024-28

[119] ASG - GAAR HY2023 Distribution PTRM - Public (Updated 31.05.22).

12. Total revenue

12.1. Key points

- We are the cheapest gas distribution network in Australia and for more than two decades our prices have trended below inflation. We are immensely proud that we have been able to deliver this outcome for our customers over such an extended period.
- Notwithstanding the challenges gas networks are facing (Chapter 3), we are looking to ensure affordable prices continue. In the next access arrangement period, we are proposing to deliver:
  - A first year price decrease of 10.83% (not taking into account the recovery of ESV levies which are recovered through a different mechanism). Once the ESV levies are incorporated, the first year price decrease is 8.2% compared with the current access arrangement period on a like for like basis. This is a significant initial saving for our customers.
  - In subsequent years, we are proposing that prices will increase by 2.35% per annum above inflation.
- The proposed revenue requirement is $1,191.3 million in unsmoothed nominal dollar terms. In real, smoothed dollar terms, the proposed revenue requirement is $1,089.9 million ($2023), or an average of $218 million, which is 2% below the expected revenue in the current access arrangement period.
- Average bills over the next access arrangement period will be 12.4% lower than the current access arrangement period, or 9.9% lower on a like for like basis including ESV levies. This decrease will be experienced by all customer segments – residential customers and small/large industrial and commercial customers.
- Our revenue proposal delivers real benefits to our customers in the short term, while also assisting us in effectively managing the uncertain future facing our network.

12.2. Chapter structure

The remainder of this chapter is structured:

- Section 12.3 provides information on the building block approach to determining total revenue.
- Section 12.4 sets out the unsmoothed and smoothed revenue for the forthcoming access arrangement period.
- Section 12.5 presents the revenue allocation to Ancillary Reference Services.

12.3. Building block approach to total revenue

The Rules require total revenue to be determined for each year of the access arrangement period using the building block approach, in which the building blocks are:

- A return on the projected capital base.
- Depreciation on the projected capital base.
- The estimated cost of corporate income tax.
- Increments or decrements resulting from the operation of an incentive mechanism to encourage gains in efficiency.
- A forecast of operating expenditure.

Each of these building block components is explained in other chapters of this proposal. Those chapters and the referenced supporting documents demonstrate that the building block proposal complies with the requirements of the NGR and the NGL, including the revenue and pricing principles and the NGO. Furthermore, our consumer engagement process (Chapter 5) has resulted in several aspects of our draft proposal being removed or changed to address concerns raised by customers, including with respect to affordability. While our customers have mixed views on the various elements of this proposal, they have indicated a preference for stable prices and our proposal does that, as well as allowing the regulatory compact on capital recovery (Chapter 3) to be fulfilled.

12.4. Total Revenue Requirements – Unsmoothed and Smoothed

12.4.1. Building block components of the revenue requirement (unsmoothed)

Our revenue requirement is $1,191.3 million (unsmoothed, nominal). The various revenue components are set out by year in the table below.

Table 12.1: Total building block revenue requirement ($m, nominal, unsmoothed)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Return on Capital	94.9	96.8	99.0	100.8	101.5	**493.0**
Return of Capital	56.0	56.6	64.7	73.9	81.5	**332.7**
Operating Expenditure[120]	62.7	66.4	66.0	67.7	70.4	**333.1**
Revenue Adjustments	-15.8	5.4	1.6	1.8	2.0	**-5.0**
Net Tax Allowance	9.6	7.2	6.4	6.8	7.5	**37.5**
Unsmoothed Revenue Requirement	**207.4**	**232.3**	**237.7**	**250.9**	**262.8**	**1,191.3**

Source: AusNet Services PTRM (2024-28). Excluding Ancillary Reference Services

Further information on each of these components is available in earlier chapters of this proposal.[121]

12.4.2. Smoothed revenue requirement

We have smoothed the revenue requirement to deliver a stable annual revenue profile over the forthcoming access arrangement period. In accordance with the requirements of rule 92(2), the revenues defined by the smoothed profile return the same NPV as the unsmoothed revenue shown in the table above.

Our smoothed revenue requirement is set out in the table below.

[120] Excluding Ancillary Reference Services
[121] The proposed return on capital is explained in Chapter 10. The proposed return of capital is explained in Chapter 9. Operating expenditure forecasts are set out in Chapter 7. The operation of the EBSS in relation to the current access arrangement period is detailed in Chapter 14. The benchmark tax liability is explained in Chapter 11.

Table 12.2: Total smoothed revenue requirement ($m, $June 2023)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Total revenue required	201.5	208.8	217.1	226.4	236.2	**1,089.9**
Price change (% real)	-10.83%	2.35%	2.35%	2.35%	2.35%	

Source: AusNet Services PTRM (2024-28)

In real terms, the changes in revenue are a decrease of 10.83% in year one, with increases of 2.35% in each subsequent year.

For the reasons set out in this access arrangement proposal, our revenue proposal is consistent with the NGR and NGL, including the revenue and pricing principles and the NGO.

12.4.3. Affordability

We have developed network plans with affordability in mind and over the last decade our network charges have consistently been the lowest in Victoria. We recognise that gas is a fuel of choice and that customers can choose to disconnect if charges are too high.

We take a long-term view on our gas charges and we want to ensure they remain stable as we know that is important to our customers. In developing this proposal, we have considered how best to future-proof prices, regardless of which decarbonisation pathway occurs (see Chapter 3).

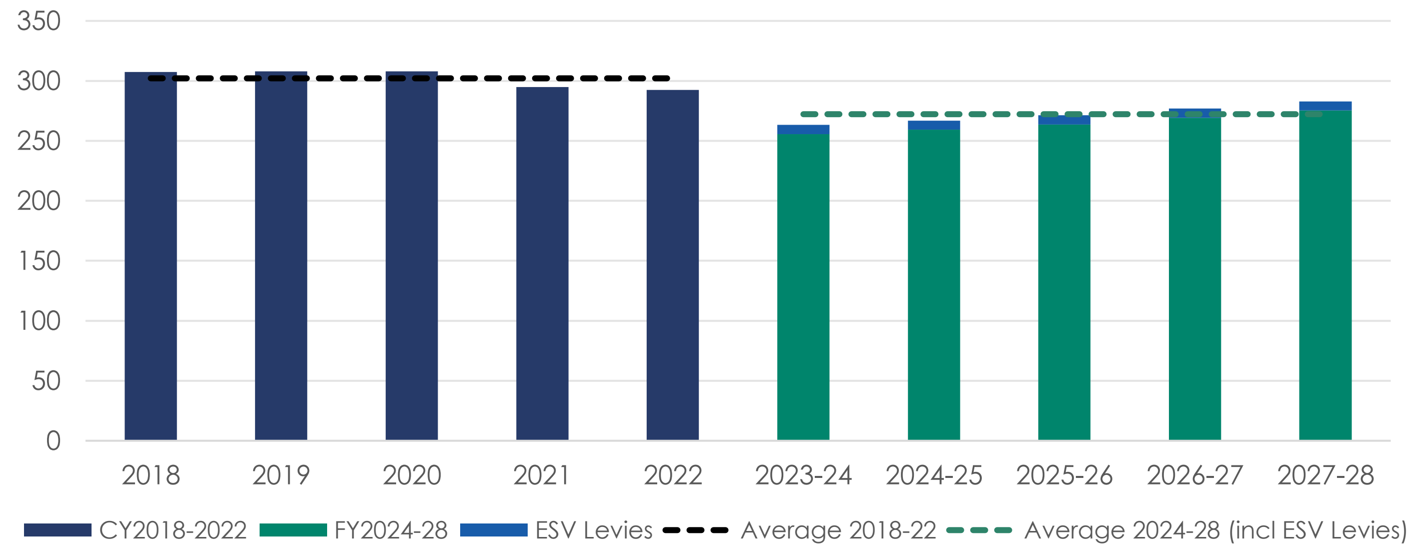
A key driver of this affordability has been ongoing strong customer growth which we have forecast to continue into this next access arrangement period (see Chapter 4). We may need to materially adjust the tariff outcomes of our proposal if Government policies which slow our connections growth are enacted.

A typical residential customers can expect to pay an average of $1,080 for their gas bill in FY24 of which the distribution component is approximately 25% (although this share will fall significantly if wholesale gas prices remain elevated). Conversely, business customers pay vastly different amounts for gas compared to residential consumers, as this is highly dependent on how much they consume or what capacity they require.

Despite our accelerated depreciation proposal, average distribution bill in the next access arrangement period will fall by approximately 12.4% in real terms compared to the 2018-22 period, or 9.9% if ESV Levies are included. Importantly, this proposal means that price shocks will be minimised in the medium to long term as we work to future-proof the network. If we held off on our proposal to accelerate depreciation, in the future, our customers will face less stable and significantly higher prices.

The figure below shows the average smoothed revenue per customer and how, relative to the current access arrangement period it is falling.

Figure 12.1: Average smoothed revenue per customer ($ June 2023)



Source: AusNet

The table below shows the average bill expected per customer in nominal dollars.

Table 12.3: Average bill by customer type ($nominal)

Customer Type	Volume	2022-23 (Current)	2023-24 (Year 1)	2024-25	2025-26	2026-27	2027-28
Small residential (GJ)	15	$187	$172	$181	$191	$201	$212
Medium residential (GJ)	40	$255	$234	$247	$260	$274	$289
Large residential (GJ)	70	$337	$309	$326	$343	$362	$381
Small commercial (GJ)	15	$194	$178	$187	$197	$208	$219
Medium commercial (GJ)	75	$377	$346	$365	$384	$405	$427
Large commercial (GJ)	700	$2,291	$2,104	$2,217	$2,333	$2,461	$2,593
Small industrial (MHQ)	5	$1,600	$1,469	$1,548	$1,629	$1,718	$1,811
Medium industrial (MHQ)	20	$6,247	$5,735	$6,043	$6,361	$6,710	$7,070
Large industrial (MHQ)	80	$19,828	$18,203	$19,181	$20,190	$21,296	$22,440

Source: AusNet

12.5. Revenue allocation to Ancillary Reference Services

Ancillary Reference Services comprise:

- Disconnection Services.
- Meter and Gas installation test.
- Reconnection Services.
- Special Meter Reading Services.
- Meter Fix or Reinstallation.
- Meter and Service Removal.
- Minor Meter Alter.

The table below shows the annual nominal revenue allocated to Ancillary Reference Services (in accordance with the requirements of rule 93) each year.

Table 12.4: Ancillary Reference Services – revenue requirements ($m, nominal)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Ancillary Service Revenue	7.5	7.8	8.1	8.4	8.7	**40.5**

Source: AusNet PTRM 2024-28

As noted above, the annual percentage change in revenue for Ancillary Reference Services is the same as the annual changes for total smoothed revenue.

In addition to Haulage Reference Services and Ancillary Reference Services, it should be noted that there is a small annual cost associated with the provision of Non-Reference Services. These services are charged on a recoverable works basis to the particular customers requesting the services.

13. Cost pass throughs

13.1. Key points

A cost pass through framework is an efficient low cost mechanism of managing unpredictable, high cost events that are beyond our control. This mechanism ensures that costs are only recovered from customers if pre-defined events occur and are responded to efficiently.

We are proposing eight nominated cost pass through events for inclusion in the 2023-27 access arrangement. These are:

- A Change in Taxes Event.
- An Insurer Credit Risk Event.
- An Insurance Coverage Event.
- A Natural Disaster Event.
- A Regulatory Change Event.
- A Retailer Insolvency Event.
- A Service Standard Event.
- A Terrorism Event.

While all our proposed cost pass throughs are part of the current access arrangement, we have proposed changes to several pass through event definitions to align those definitions with the definitions accepted by the AER in more recent regulatory decisions.

We have in place efficient and prudent risk mitigation measures to manage risk during the access arrangement period, which we utilise instead of relying on the pass-through mechanism. Through effective risk management, we ensure the safety, reliability, and security of supply to our customers as far as practicable.

13.2. Chapter structure

The remainder of this chapter is structured:

- Section 13.3 provides an overview of the cost pass through framework.
- Section 13.4 outlies the existing pass through definitions that we intend to keep unchanged.
- Section 13.5 summarises our proposed amendments to existing pass through event definitions and the rationale for those changes.
- Section 13.6 provides details of where additional information on issues raised in this chapter can be found.

13.3. Overview of the cost pass through framework

The NGR recognises that a service provider may experience an event during an access arrangement period which increases the costs of providing services beyond the level allowed for in the service provider's approved expenditure forecasts.[122] In broad terms, the cost pass through arrangements allow the service provider to recover the difference between its regulatory allowance and its actual costs.

[122] See Rule 97(1).

Cost pass through arrangements are designed to apply in respect of unpredictable, high cost events. The arrangements serve to maintain prices at least cost by excluding these unpredictable costs from the service provider's regulatory allowance (and therefore from tariffs) unless and until a pass through event occurs. This approach delivers efficient outcomes, which are clearly preferable to the alternative approach of including ex ante allowances in the building blocks to compensate distributors for the speculative costs of unpredictable events. Having a separate cost recovery mechanism for these low probability, high cost events ensures services are provided at the lowest sustainable cost, which is thus in the long-term interests of consumers.[123]

Consistent with the AER's preference to develop a consistent approach across electricity and gas networks, we have assessed the current pass through event definitions against equivalent definitions and have proposed some changes to promote consistency. While most of these changes are minor, more significant amendments were required for the Insurance Cap Event, which we renamed (consistent with recent AER decisions) the Insurance Coverage Event.[124]

We reserve the right to propose new pass through events or make further amendments to its existing Relevant Pass Through Events in our revised access arrangement proposal to promote consistency between the Victorian gas distribution businesses, or in response to other industry or market changes.

13.4. Unchanged nominated cost pass through events

We do not propose to make any changes to the following event definitions:

- Change in Taxes Event.
- Regulatory Change Event.
- Retailer Insolvency Event.

Our review of these definitions reveal they are consistent with the definitions accepted by the AER in other regulatory determinations and/or used in the National Electricity Rules, and continue to promote the achievement of the NGO.

13.5. Amendments to existing nominated cost pass through events

This section sets out the amendments we propose to make to certain Relevant Pass Through Event definitions in our current access arrangement. In each case, proposed deletions are shown in strikethrough text ~~like this~~, and proposed insertions in red font like this. We have also provided a clean version of the definitions in Appendix 15.

13.5.1. Insurer credit risk event

13.5.1.1. Proposed definition

The proposed definition of an Insurer Credit Risk Event is:

> **Insurer Credit Risk Event** means if an insurer of the Service Provider becomes insolvent and, as a result in respect of an existing or potential claim for a risk that was insured by the insolvent~~'s~~ insurer, ~~experiences an Insolvency Event, as a result of which~~ the Service Provider:
>
> (a) ~~in respect of a claim for a risk that was insured by the Service Provider's insurer,~~ is subject to a materially higher or materially lower claim limit or a materially higher or materially lower deductible than would have otherwise ~~was~~ apply~~ied~~ under ~~that~~ the insolvent insurer's policy; or
>
> (b) incurs material additional costs associated with funding an insurance claim which would have otherwise been covered by the insolvent insurer.

[123] See NGR.
[124] AER, Final Decision, AusNet Services Distribution Determination 2021-26, Attachment 15: Pass through events, April 2021, pp. 15-9, AER, Final Decision, SA Power Networks Distribution Determination 2020–25, Attachment 14 Pass through events, June 2020, pp. 13–14; AER, Final Decision, Ergon Energy Distribution Determination 2020–25, Attachment 14 Pass through events, June 2020, pp. 9–10; AER, Final Decision, Energex Distribution Determination 2020–25, Attachment 14 Pass through events, June 2020, pp. 9–10.

Note: In assessing ~~making its decision to approve or reject a proposed reference tariff variation arising from~~ an Insurer Credit Risk Event, the Regulator will have regard to, amongst other things:

(c) the Service Provider's attempts to mitigate and prevent the event from occurring by reviewing and considering the insurer's track record, size, credit rating and reputation; and~~.~~

(d) in the event that a claim would have been covered by the insolvent insurer's policy ~~made after the insurer became insolvent~~, whether the Service Provider had reasonable opportunity to insure the risk with a different insurer.

13.5.1.2. Rationale

The cost impacts to us of one of our insurers becoming insolvent are potentially significant. By being forced to insure with another provider, we could be forced to accept higher premiums, or a lower claim limit or higher deductible. Our insurance coverage is significant and hence an insurer being unable to pay a claim, or part of a claim, could materially affect our ability to provide services to our customers.

13.5.1.3. Risk mitigation

We set minimum requirements and consider several risk management factors when assessing whether to insure with a particular provider, such as the insurer's track record, size, credit rating and reputation. Our insurance coverage is also diversified across both domestic and international providers. The combination of these approaches can be considered to provide a prudent and efficient level of risk mitigation against a potential insurer credit risk event.

Although we mitigate this risk to the best of our ability by ensuring our insurers have the equivalent of an S&P rating of A or above, the insolvency of one or more of our insurers is an event that is outside our control. The probability of insurer insolvency is also such that it is not prudent or efficient to take out multiple insurance policies to remove the risk altogether. Hence, we believe that a pass through mechanism is currently the most appropriate regulatory approach for addressing the costs arising from an insurer becoming insolvent.

Our proposed definition aligns with that approved by the AER in its January 2022 final decision for AusNet Services' Transmission Determination.[125]

13.5.2. Insurance coverage event

Consistent with recent AER decisions we are proposing to amend our Insurance Cap Event definition to align with the Insurance Coverage Event definition approved by the AER in a number of recent regulatory determination. This has required significant amendment to the current text.

13.5.2.1. Proposed definition

Insurance ~~Cap~~ Coverage Event means an event whereby:

(a) the Service Provider:

(1) makes a claim or claims ~~on a relevant insurance policy~~ and receives the benefit of a payment or payments under ~~that~~ a relevant insurance policy or set of insurance policies;

(2) would have been able to make a claim or claims under a relevant insurance policy or set of insurance policies but for changed circumstances; and

(b) the Service Provider incurs costs:

(1) beyond ~~the~~ a relevant policy limit for that policy or set of insurance policies; or

(2) that are unrecoverable under that policy or set of insurance policies due to changed circumstances; and

(c) the costs referred to in paragraph (b) ~~beyond the relevant policy limit~~ materially increase the costs to the Service Provider of providing Reference Services.

For the purposes of this Insurance ~~Cap~~ Coverage Event:

(d) 'changed circumstances' means movements in the relevant insurance liability market that are beyond the control of the Service Provider, where those movements mean that it is no longer possible for the Service Provider to take out an insurance policy or set of insurance policies at all or on reasonable commercial terms that include some or all of the costs referred to in paragraph (b) above within the scope of that insurance policy or set of insurance policies;

[125] AER, Final Decision – AusNet Services Transmission Determination 2022 to 2027, Attachment 13, Pass through events, January 2022.

(e) 'costs' means the costs that would have been recovered under the insurance policy or set of insurance policies had:

(1) the limit not been exhausted; or

(2) those costs not been unrecoverable due to changed circumstances;

(f) a relevant insurance policy or set of insurance policies is an insurance policy or set of insurance policies held during the ~~Fifth~~ Sixth Access Arrangement Period or a previous period in which access to the pipeline services was regulated;

(~~e~~g) the Service Provider will be deemed to have made a claim on a relevant insurance policy or set of insurance policies if the claim is made by a related party of the Service Provider in relation to any aspect of the Distribution System or the Service Provider's business; and

(h) the Service Provider will be deemed to have been able to make a claim on a relevant insurance policy or set of insurance policies if, but for changed circumstances, the claim could have been made by a related party of the Service Provider in relation to any aspect of the Distribution System or the Service Provider's business.

Note: In making a determination on an Insurance ~~Cap~~ Coverage Event, the Regulator will have regard to~~, amongst other things~~:

(1) the relevant insurance policy or set of insurance policies for the event;

(2) the level of insurance that an efficient and prudent Service Provider would obtain, or would have sought to obtain, in respect of the event; and

(3) any information provided by the Service Provider to the Regulator about the Service Provider's actions and processes; and

(4) any ~~assessment~~ guidance published by the Regulator ~~of~~ on the matters the Regulator will likely have regard to in assessing any Insurance Coverage Event that occurs ~~Service Provider's insurance in making its access arrangement decision for the relevant period~~.

13.5.2.2. Rationale

We maintain a level of insurance cover that is commensurate with the scale and size of our operations, the risks assessed to be associated with our operations, industry standards and industry best practices. The premiums associated with our insurance cover are incorporated in our proposed opex forecast through our base year opex. Our base year opex also includes actual self-insurance costs incurred that relate to liability losses falling below the deductible for our insurance cover. We are, however, exposed to the risk that we incur liability losses that exceed our insurance coverage.

Including the Insurance Coverage Event is a prudent and efficient way to mitigate this risk. Our proposed amendments also consistent with recent AER decisions.

Absent the Insurance Coverage Event, we will be precluded from recover at least the efficient costs we incur in providing Relevant Services as the costs we would incur were such an event to occur have not been allowed for elsewhere in this proposal.

13.5.2.3. Risk mitigation

We acknowledge the complementary nature of commercial insurance coverage and the pass through framework, which gives us the opportunity to achieve an optimal blend of cover. As an efficient and prudent provider of Relevant Services, we set our insurance limits based on a level of insurance cover that is commensurate with the scale and size of our operations, the risks assessed to be associated with our operations, as well as industry standards and best practices.

13.5.3. Natural disaster event

13.5.3.1. Proposed definition

The proposed definition of a Natural Disaster Event is:

Natural Disaster Event means any natural disaster including, but not limited to cyclone, fire, flood or earthquake that occurs during the ~~Fifth~~ Sixth Access Arrangement Period and materially increases the costs to the Service Provider of providing Reference Services, provided the cyclone, fire, flood or other event was:

(a) a consequence of an act or omission that was necessary for the Service Provider to comply with a Regulatory Instrument; or

(b) not a consequence of ~~the~~ any other act~~s~~ or omission~~s~~ of the Service Provider.

Note: In assessing a Natural Disaster Event pass through application, the Regulator will have regard to, amongst other things:

(c~~a~~) whether the Service Provider has insurance against the event;

(d~~b~~) the level of insurance that an efficient and prudent Service Provider would obtain in respect of the event.

13.5.3.2. Rationale

Natural disaster events, by definition, cannot be prevented or avoided. The cost impact of a natural disaster on our network assets can be potentially significant. Where it is possible, our insurance coverage protects against loss and damage caused by natural disasters. However, the cost impact of a natural disaster could materially exceed the coverage provided by these policies. We also note that while the probability of natural disasters occurring is such that it is not prudent or efficient to obtain continuous insurance cover to remove this risk entirely, and to pass this cost onto consumers. Therefore, the combination of our insurance strategy and the pass through event definition represents the preferred prudent and efficient approach.

Our proposed definition of a Natural Disaster event aligns with that approved by the AER in its January 2022 final decision for AusNet Services' Transmission Determination.[126]

13.5.3.3. Risk mitigation

We employ a range of strategies to minimise and mitigate the exposure of the gas network to natural disasters. For the majority of our assets, exposure to natural disasters is reduced as far as reasonably practicable through minimum design standards to ensure assets can withstand seismic events, flood, fire and other natural catastrophes. We also invest in restoration and recovery capability.

Where it is feasible and efficient to do so, we seek to transfer the risks posed by natural disasters by obtaining external insurance cover or self-insuring. However, as the AER is aware, complete insurance cover for natural disaster events is either not available, or not available at an efficient cost.

These considerations demonstrate the need for the Natural Disaster Event, which provides the most cost-effective risk mitigation strategy.

13.5.4. Service standard event

13.5.4.1. Proposed definition

The proposed definition of a service standard event is:

Service Standard Event means a legislative or administrative act or decision that ~~falls within no other category of Relevant Pass Through Event that~~:

(a) has the effect of:

(1) substantially varying, during the course of an access arrangement period, the manner in which the Service Provider is required to provide a Reference Service;

(2) imposing, removing or varying, during the course of an access arrangement period, minimum service standards applicable to Reference Services; or

(3) altering, during the course of an access arrangement period, the nature or scope of the Reference Services, provided by the Service Provider; and

(b) materially increases or materially decreases the costs to the Service Provider of providing Reference Services.

13.5.4.2. Rationale

A legislative or administrative act or decision can reasonably be expected to have a significant impact on the cost of providing a Relevant Service over the network. While we look to actively engage with different levels of Government to ensure ongoing communication and a no surprise environment, including with respect to the timing of any decisions on service standards, we can be taken by surprise. Where that occurs, this can result in significantly higher costs.

Our proposed amendment to the proposed definition of this event are minor – we are proposing to remove several words to mirror the definition of the save event in the National Electricity Rules.

[126] AER, Final Decision – AusNet Services Transmission Determination 2022 to 2027, Attachment 13, Pass through events, January 2022.

13.5.4.3. Risk mitigation

We employ a range of strategies to minimise and mitigate the exposure of the gas network to the cost of legislative or administrative acts or decisions that may be made during the course of an access arrangement period. A key component of our strategy is stakeholder engagement.

Our stakeholder engagement looks to influence energy sector structural arrangements and the regulatory framework and our primary approach to do this involves building strong relationships with policy makers on regulatory issues. It also ensures that where prospective regulatory change is contemplated, we are aware of the scale, scope and timing implications of the change so that we can, to the greatest extent possible, include the implementation and compliance costs in our expenditure forecasts.

Our approach aims to:

- strengthen our credibility and trust with policy-makers and regulators, enhancing opportunities to engage and contribute to solutions; and
- achieve good practice regulatory approaches over the medium term.

In most situations, our approach will be successful and the likelihood of a Service Standard Event occurring within an access arrangement period is reduced as far as reasonably practicable. Despite our best efforts, ensuring complete engagement by Government on all proposed changes (including those that might have a material impact) is often not possible. Consequently, there is an ongoing need for a Service Standard Event definition, which provides the most cost-effective risk mitigation strategy.

13.5.5. Terrorism event

13.5.5.1. Proposed definition

The proposed definition of a Terrorism event is:

> **Terrorism Event** means an act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of in connection with any organisation or government), which:
>
> (a) from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear); and
>
> (b) which materially increases the costs to the Service Provider of providing Reference Services.
>
> Note: ~~for the avoidance of doubt~~, iIn making a determination on a Terrorism Event, the Regulator will have regard to, amongst other things:
>
> (c) whether the Service Provider has insurance against the event;
>
> (d) the level of insurance that an efficient and prudent service provider would obtain in respect of the event; and
>
> (e) whether a declaration has been made by a relevant government authority that a~~n act of t~~Terrorism Event has occurred.

13.5.5.2. Rationale

An act of terrorism against national critical infrastructure such as a gas distribution network can reasonably be expected to have a significant impact on the cost of providing services over the network. For example, immediate physical repairs to infrastructure may be required to maintain or restore reliable supply. It may also be necessary to implement additional security processes and introduce new preventative measures to deter or prevent future attacks. Depending on the scale and impact of the event, the cost impact may be significant.

We are best placed to manage the majority of the risk posed by an act of terrorism. To that end, we have taken numerous steps to substantially mitigate risks posed by an act of terrorism to our network. However, it is not possible to eliminate the entirety of the risk we face as to do so would require a level of expenditure (and therefore a cost to our customers) that is neither prudent nor efficient. Therefore, it is appropriate to share part of the risk of an act of terrorism occurring with our customers by proposing a nominated pass through event.

Our current arrangement includes a Terrorism Event definition. We have reviewed the AER's analysis of the Terrorism Event definitions approved in other decisions, and we do not consider there is a strong need to change our current definition. We have, however, made some minor changes to the definition to remove unnecessary wording and simplify the definition.

13.5.5.3. Risk mitigation

We have several security and other measures in place to prevent acts of terrorism against our gas network, and to mitigate the cost impact of such an event, should one occur. We manage these risks by focusing primarily on the protection of key assets and critical infrastructure, including the software and underlying technology used to operate those assets. For example, our foundational security capabilities include:

- ensuring appropriate physical security controls are in place to deter, detect or respond to physical security breaches, including installing CCTV cameras at all major asset sites and employing security patrols; and
- taking reasonable steps to design, operate and maintain our IT systems in accordance with ISO 27001: Information Security Management and ISO 27002 Information Technology: Security Techniques – Code of Practice for information security controls, which represents international best practice for IT security.

We also periodically test whether it is cost effective to obtain third party insurance or to self-insure against losses resulting from acts of terrorism. The relative infrequency and potentially very high costs of a terrorism event creates significant practical challenges for insuring such events, including calculating the amount of cover required and the self-insurance premium required.

A pass through mechanism provides a more efficient arrangement for managing the cost impacts in the unlikely circumstances that a terrorism event occurs and materially increases our costs.

13.5.6. Relevant pass through event

We also propose to amend the definition of Relevant Pass Through Event to reflect the renaming and subsequent re-ordering (in alphabetical order) of our event definitions.

The amended definition we have proposed is:

> **Relevant Pass Through Event** means:
>
> (a) a Change in Taxes Event;
>
> (b) an Insurance Coverage ~~Cap~~ Event ~~an Insurer Credit Risk Event~~;
>
> (c) an Insurer Credit Risk Event ~~an Insurance Cap Event~~;
>
> (d) a Natural Disaster Event;
>
> (e) a Regulatory Change Event;
>
> (f) a Retailer Insolvency Event;
>
> (g) a Service Standard Event; or
>
> (h) a Terrorism Event.
>
> For the purpose of any Relevant Pass Through Event that includes a reference to materiality, an event is considered to materially increase or materially decrease costs where that event has an impact which is equal to or greater than one per cent of the smoothed forecast revenue specified in the Regulator's Final Decision, in one or more of the years for the Access Arrangement Period in which the costs are incurred.

13.6. Supporting documents

The following document provides a clean version of our proposed amendments to existing nominated cost pass through events:

- ASG – GAAR – Appendix 15: Proposed amendments to existing nominated cost pass through events (clean) – Date – PUBLIC.

14. Incentives

14.1. Key points

- We have a strong record of delivering lower operating costs and improved service levels in response to the incentive framework. Incentive regulation helps align the interests of network service providers with the long-term interests of consumers and drive better customer outcomes.
- For the forthcoming access arrangement period, we are proposing that the following incentive schemes should be applied:
  - Efficiency Benefit Sharing Scheme (EBSS), which provides incentives to make operating expenditure efficiency improvements.
  - Capital Expenditure Sharing Scheme (CESS), which provides constant incentives to make capital expenditure efficiency gains.
  - Guaranteed Service Levels (GSLs), which compensate customers who have experienced service performance below the expected standard.
- The targets from our proposed incentive schemes are an input to our asset management strategy and the work programs that underpin our proposal. Our capex and opex proposals are outlined in Chapter 6 and Chapter 7 respectively.
- We have excluded the Gas Network Innovation Scheme (GNIS) from our proposal to address our customers' immediate affordability issues.

14.2. Chapter structure

The remainder of this chapter is structured as follows:

- Section 14.3 explains the EBSS, calculates the efficiency carryover amount from the current access arrangement period, and sets out the proposed application of the EBSS for the forthcoming period.
- Section 14.4 proposes the application of a CESS.
- Section 14.5 provides information on GSLs.
- Section 14.6 provides details where additional information can be found.

14.3. Efficiency benefit sharing scheme

The purpose of the EBSS is to provide a mechanism for the sharing between network service providers and customers of efficiency gains and losses relating to operating expenditure during the access arrangement period. The design of the scheme ensures that network service providers face a consistent incentive to deliver efficiency savings in each year of the access arrangement period. The interaction between the EBSS and the AER's 'revealed cost' approach ensures that opex efficiencies are shared with customers over time.

In summary, the rationale for applying the EBSS is that it improves the incentive properties of the regulatory framework, and in doing so, promotes the long-term interests of customers in accordance with the NGO.

The remainder of this section sets out:

- The calculation of the current period's efficiency carryover amount which will be recovered during the forthcoming period.
- Our views on the operation of the EBSS in the next access arrangement period.

14.3.1. Current period carryover amount

We have calculated the efficiency carryover amount to be recovered during the forthcoming period in accordance with clause 6.4, Part B of the current access arrangement. In accordance with these provisions, we have excluded the following costs from the operation of the efficiency carryover:

- Debt raising costs.
- Unaccounted for Gas (UAFG).
- Movement in provisions related to opex.
- Non-reference services.
- Ancillary reference services.

The table below sets out the calculation of our incremental efficiency gains and losses in the current access arrangement period.

Table 14.1: Calculation of the EBSS carryover amount ($m, real 2022-23)

	2018	2019	2020	2021	2022
Total opex (excluding debt raising costs)	65.3	64.8	64.5	62.0	54.9
Less Unaccounted for Gas	0.0	2.5	2.5	0.0	0.0
Less Movement in Provisions	-0.7	2.1	0.8	-1.4	0.0
Less Non-reference services	0.3	1.2	2.2	4.7	0.0
Less Ancillary reference services	4.7	4.5	3.9	2.1	4.2
Opex for EBSS	60.9	54.5	55.1	56.5	57.3[127]
Approved allowance	57.7	58.4	59.1	60.3	61.1
Incremental efficiency gain/loss	**1.4**[128]	**7.1**	**0.1**	**-0.3**	**0.0**
	2023-24	**2024-25**	**2025-26**	**2026-27**	**2027-28**
Carryover of efficiency gain/loss made in:					
2018	0.7				
2019	7.1	3.6			
2020	0.1	0.1	0.1		
2021	-0.3	-0.3	-0.3	-0.1	
2022	0.0	0.0	0.0	0.0	0.0
Efficiency carryover amount	**7.7**	**3.4**	**-0.2**	**-0.1**	**0.0**

Source: AusNet
Note: Values are net of the EBSS amounts proposed for the half year period from 1 January to 30 June 2023.

[127] This is the estimate of 2022 opex used to calculate the carryovers applied in the 2018-23 period. It is not the actual opex incurred.
[128] The incremental gain for 2018 takes into account the forecast and actual spend of 2015 and 2017 data that is not presented here.

14.3.2. Proposed application of the EBSS

A key issue in relation to the application of the EBSS is to define those cost categories that are excluded from its operation. For the forthcoming access arrangement period, we are proposing (consistent with the exclusions we have in the current access arrangement period) the following exclusions:

- Debt raising cost.
- Unaccounted for gas.
- Movement in provisions related to opex.
- Non-reference services.
- Ancillary reference services.

In summary, our proposed application of the EBSS:

- Is consistent with the AER's approach in electricity distribution.
- Will continue to promote efficient outcomes for the long-term interests of consumers.

14.4. Capital efficiency sharing scheme

The CESS provides an analogous incentive in relation to capex as the EBSS provides in relation to opex. This section sets out our proposal with respect to the application of the CESS, specifically:

- The calculation of the current access arrangement period's efficiency carryover amount which will be recovered during the forthcoming period.
- Our proposal for the operation of the CESS in the forthcoming period.

14.4.1. Current period carryover amount

We have calculated the efficiency carryover amount to be recovered during the forthcoming access arrangement period in accordance with the AER's final decision on the application of the CESS for the current access arrangement period.

This calculation involved the following steps:

- Calculate the capex applicable to the CESS by removing customer contributions and asset disposal from total capex.
- Calculate the efficiency gain for each year in net present value terms.
- We calculate the CESS payments taking into account the financing benefit of any underspend and financing cost of any overspend.
- Apply a sharing ratio of 30/70 to service providers and consumers respectively – that is, we will bear 30 per cent of any loss and will retain 30% of any gain, and the remaining 70% will be returned to gas pipeline users.
- We apply a Contingent Payment Factor (CPF) which is a mechanism designed to offset CESS rewards when our performance reduces from historical outcomes. The next section provides a description of the CPF.

14.4.1.1. Contingent Payment Factor

The CPF is an asymmetric mechanism that is designed to offset CESS rewards when our performance is below the AER's lower threshold, and not increase the CESS reward if our performance is above the upper threshold.

Our performance is measured using the Asset Performance Index (API), where the API score accounts for customer service outcomes (unplanned System Average Interruption Frequency Index or SAIFI and unplanned System Average Interruption Duration Index or SAIDI) and the health of our network (number of gas leaks specific to mains, services and meters). Specifically, the API score is a weighted average of the underlying components, which is then compared to an upper threshold of 100, and a lower threshold of 80.

The CPF is calculated as follows[129] :

- If our API score is greater than 100, then our CPF is 1, meaning we receive the full CESS payment.
- If our API score is less than 80, then our CPF is zero, meaning we do not receive any CESS payment.

[129] Assuming our share is greater than net financing benefit.

- If our API is greater than 80 but less than 100, then our CPF will be determined according to the following formula:

$$CPF = \frac{(API - 80)}{(100 - 80)}$$

Table 14.2 (below) provides the calculation of our CPF where:

- Our actual performance, for each component of the API, is the average over the 2018-2021 period. This is consistent with Annexure A (Asset Performance Index), Part B of the current 2018-22 access arrangement.
- We have sourced our targets and weightings from clauses 6 and 7 of Annexure A, Part B of the current 2018-22 access arrangement.
- We have calculated each components' index in accordance with the following formula[130] :

$$Index = 200 - \left(\frac{Actual}{Target}\right) x\ 100$$

Table 14.2: Calculation of the Contingent Payment Factor

	Actual	Target	Index	Weight	Contribution
Unplanned SAIFI	22.10	20.52	89.70	25.00%	23.08
Unplanned SAIDI	809.88	891.63	109.14	25.00%	27.29
Mains leaks	0.04	0.09	156.48	20.40%	32.50
Services leaks	4.51	5.52	115.24	23.00%	27.20
Meter leaks	18.60	15.99	79.80	6.60%	5.52
API score					115.59
Components	**Value**				
API score	115.59				
Upper threshold	100				
Lower threshold	80				
Contingent Payment Factor	100%				

Source: AusNet

14.4.1.2. Calculation of the CESS carryover amount

Table 14.3 below summarises the calculation of our CESS carryover amount, taking into account the CPF described in the previous section. We have not proposed any capex deferrals from the current period to the next access arrangement period.

[130] Clause 6, Annexure A, Part B of the Access Arrangement for the Distribution System, 2018-2022, AusNet's gas access arrangement.

Table 14.3: Calculation of the CESS carryover amount ($m, real 2022-23)

	2018	2019	2020	2021	2022
Capex allowance	106.91	106.03	104.22	97.22	95.78
Actual capex	98.15	105.79	93.77	97.86	84.98
Underspend	8.76	0.23	10.45	-0.64	10.80
Year 1 benefits		0.30	0.29	0.29	0.27
Year 2 benefits			0.01	0.01	0.01
Year 3 benefits				0.33	0.31
Year 4 benefits					-0.02
Year 5 benefits					
NPV underspend	10.67	0.27	11.49	-0.69	10.80
NPV financing benefit	0.00	0.34	0.33	0.67	0.57
Total underspend (NPV) adjusted for deferrals	32.55				
Relevant sharing ratio	30%				
Consumer share	22.79				
NSP share	9.77				
Total NSP financing benefit (NPV)	1.91				
NPV of CESS payments (post-adjustment and pre-CPF) as at 31 December 2022	7.85				
Contingent Payment Factor (CPF)	100%				
NPV of CESS payments (post-adjustment and post-CPF) as at 31 December 2022	7.85				
NPV of CESS payments (post-adjustment and post-CPF) as at 30 June 2023	8.03				
	2023-24	2024-25	2025-26	2026-27	2027-28
CESS payments per year	1.70	1.70	1.70	1.70	1.70

Source: AusNet

14.4.2. Proposed application of the CESS

We have proposed a CESS for the 2024-28 access arrangement period. The proposed scheme is like the CESS currently in use and involves the use a CPF. Further information on our proposal, including the potential role of exclusions and targets, is outlined below.

14.4.2.1. Contingent Payment Factor

We have proposed a CPF for the 2024-28 access arrangement period that is like the current mechanism, whereby it is asymmetric and designed to offset CESS rewards when our performance is below a threshold, and not increase the CESS reward if our performance is above the threshold.

We have proposed the same approach and methodology as current for the following variables:

- Asset Performance Index: We have proposed the same customer service outcomes and network health indicators (including weights) as current for the calculation of our API score i.e.,:
  - Unplanned SAIFI measured in outages per 1000 customers (25.0%).
  - Unplanned SAIDI measured in unplanned customer minutes off supply per 1000 customers (25.0%).
  - Mains leaks measured in mains leaks per km of mains length (20.4%).
  - Services leaks measured in services leaks per 1000 customers (23.0%).
  - Meter leaks measured in meter leaks per 1000 customers (6.6%).
- CPF: We have adopted the same CPF formula as current, including the same upper (100) and lower thresholds (80).

14.4.2.2. Exclusion

When the CESS was first introduced to gas distributors at the commencement of the current access arrangement period, it incorporated a CPF as a counterbalancing service parameter to the CESS. That is, a CPF would ensure that capex savings do not occur at the expense of falling performance. This was considered appropriate at the time as gas distributors are not subject to a separate reliability scheme like the Service Target Performance Incentive Scheme (STPIS) in the electricity sector, whereby falling reliability attracts penalties and increases in reliability earns us a reward. At the time, there was no evidence that an asymmetric scheme would dilute the purpose and intent of the CESS.

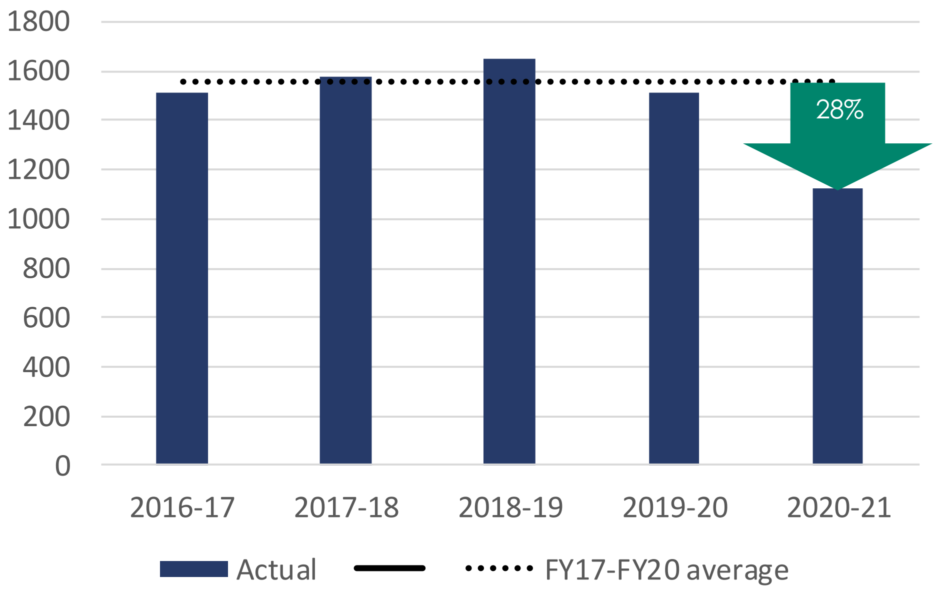
However, in April 2019, water entered our network at Yarraville and caused widespread outages over a few weeks. It was a severe outage outside of our control, and there were concerns that its inclusion in our performance data had the potential to reduce our 2018-2022 performance by 20% or more. If that eventuated, that single event, would have resulted in the incentive on capex efficiency being lost for the remaining 3.5 years of the current period. That would be an undesirable outcome, including for customers, as they share in the benefits of capex efficiency at a rate of 70%.

While we have not proposed an exclusion mechanism for the forthcoming access arrangement period, the introduction of an exclusion mechanism, where events over a certain threshold would be excluded from counting towards a network's actual performance, may have merit.

14.4.2.3. Targets

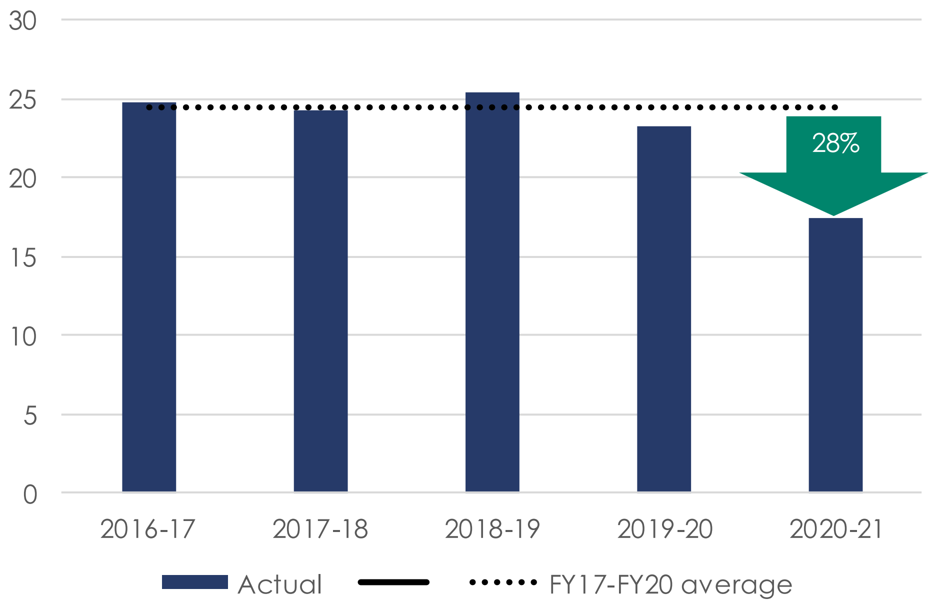
Since the start of COVID-19 in early 2020, Melbourne has experienced more than 260 lockdown days – the longest lockdown experienced by any city or country across the globe. This has meant numerous people isolating, working from home, and restricting their movement to within a few kilometres from home. As a result of fewer movements, the number of reported leaks and unplanned SAIFI have reduced, particularly for 2020-21 where we experienced a 28% decline compared to the average over 2016-17 to 2019-20 period. See Figure 14.1 and Figure 14.2.

Figure 14.1: Actual leaks from 2016-17 to 2020-21 (5 years)



Source: AusNet

Figure 14.2: Unplanned SAIFI from 2016-17 to 2020-21 (5 years)



Source: AusNet

As a result, we have proposed API targets that reflect our average performance over the 2016-17 to 2019-20 period (4 years). Incorporating our 2020-21 results would produce an unrealistically low target that does not reflect our actual historical performance. See Table 14.4 for proposed targets.

Table 14.4: API targets and weights

	Weight	2016-17	2017-18	2018-19	2019-20	Target
Unplanned SAIFI	25.0%	24.76	24.30	25.48	23.28	24.45
Unplanned SAIDI	25.0%	797.58	692.66	1463.27	579.13	883.16
Mains leaks	20.4%	0.0496	0.0446	0.0425	0.0429	0.0449
Services leaks	23.0%	5.11	5.14	5.26	4.59	5.03
Meter leaks	6.6%	20.97	21.53	21.99	19.57	21.01

Source: AusNet

14.4.2.4. Forecast capex

The table below sets out the proposed capex for the CESS in the forthcoming access arrangement period.

Table 14.5: Proposed forecast capex for the CESS ($m, real 2022-23)

	2023-24	2024-25	2025-26	2026-27	2027-28
Forecast Net Capex for CESS	110.7	113.9	111.2	98.5	88.5

Source: AusNet

14.5. Guaranteed Service Levels

We provide GSLs in relation to appointment times, connection services and interruptions. The purpose of the GSLs is to compensate specific customers if our performance falls beneath the required standard. The GSLs therefore provide us with an incentive to deliver efficient services to our customers.

The GSLs are specified in Schedule 1, Part E of the Victorian Gas Distribution Code of Practice, which continues to be regulated by the ESC. [131] We propose that the existing GSLs should be maintained for the forthcoming access arrangement period.

For ease of reference the current GSLs are reproduced in the table below.

Table 14.6: Guaranteed Service Levels

Area of service	Threshold to incur GSL payment	GSL amount
Appointments	Failure to attend appointment within agreed appointment window: Customer present – 2 hours Customer absent – agreed date	$50 per event
Connections	Failure to connect a customer within 1 day of agreed date	$80 per day (max of $240)
Repeat interruptions	Unplanned interruptions to a customer in a calendar year period resulting from faults in the distribution system: Upon fifth interruption Upon tenth interruption	 $150 Additional $150
Lengthy interruptions	Gas supply interruptions to a customer not restored: Within 12 hours Within 18 hours	 $150 Additional $150

Source: ESC

[131] The Victorian Gas Distribution Code can be accessed here: https://www.esc.vic.gov.au/electricity-and-gas/codes-guidelines-and-policies/gas-distribution-system-code#tabs-container1 (accessed 17/02/2022).

15. Reference services

15.1. Key points

- For the forthcoming access arrangement period we are proposing:
  - To retain the three current Haulage Reference Services, namely its Tariff V Haulage Reference Service, Tariff M Haulage Reference Service, and Tariff D Haulage Reference Service.
  - The adopt the Ancillary Reference Services set described in our Reference Service Proposal, which includes three new services.
- The proposed Ancillary Reference Services and the Haulage Reference Services are likely to be sought by a significant part of the market in the forthcoming access arrangement period. As such, these services are classified as 'Reference Services' in accordance with the NGR.
- Our proposed Reference Services are unchanged from our Reference Service Proposal, which the AER approved in November 2021.

15.2. Chapter structure

The remainder of this chapter is structured:

- Section 15.3 outlines the NGR requirements for reference services.
- Section 15.4 specifies the haulage reference services we are proposing to offer in the forthcoming access arrangement period.
- Section 15.5 specifies the ancillary reference services we are proposing to offer in the forthcoming access arrangement period.

Our Reference Tariffs and Reference Tariff Policies are set out in Part B, while our approach to determining the tariff charging structure and prices is outlined in Chapter 17.

15.3. Rule requirements for reference services

On 1 July 2021, we submitted to the AER a reference service proposal for our gas distribution network in accordance with National Gas Rule 48. The AER's final decision, which was published in November 2021, approved our reference service proposal. In accordance with Rule 47A, our proposed reference services are consistent with the AER's final decision.

15.4. Haulage reference services

We are proposing to retain our current Haulage Reference Services in the forthcoming access arrangement period. That is, we are proposing to retain:

- **Tariff V Haulage Reference Service**: The Haulage Reference Service where the withdrawal of gas is at a Tariff V Distribution Supply Point. This includes domestic and commercial customers who consume less than 10,000 Gigajoules of gas in a 12 month period, and/or less than 10 Gigajoules in any one hour. We note that:
  - Business customers use more gas throughout the year whereas domestic customers use more energy during the peak period.

  - Different parts of our network have different operating costs, this is reflected in four Tariff V zones (Central, Adjoining Central, West and Adjoining West).
  - Our Tariff V has four declining block rates based on a daily consumption range that recognise that the marginal costs of delivery decline as volumes increase.
- **Tariff D Haulage Reference Service**: The Haulage Reference Service where the withdrawal of gas is at a Tariff D Distribution Supply Point, but does not include Tariff D connection. To qualify for Tariff D, a customer should be using or expecting to use either more than 10 Terajoules of gas in a 12 month period, or more than 10 Terajoules in an hour. In addition to the tariff charges, customers on Tariff D are required to pay an operations and maintenance (O&M) charge for any dedicated distribution assets, in particular the meter and regulator set that are installed at the connection point.
- **Tariff M Haulage Reference Service**: The Haulage Reference Service where the withdrawal of gas is at a Tariff M Distribution Supply Point. To qualify for Tariff M, a customer previously taking supply under Tariff V Haulage Reference Service should be using either more than 10 Terajoules of gas in a 12 month period, or more than 10 Terajoules in an hour. Tariff M customers are not required to pay any additional charges for O&M as these have been embedded in the tariff, other than the cost of operating and maintaining metering and data loggers to provide gas usage data.

These Haulage Reference Services are likely to continue to be sought by a significant part of the market during the forthcoming access arrangement period.

15.5. Ancillary reference services

We are proposing to retain the current suite of Ancillary Reference Services that are requested by retailers on behalf of our shared network and retail customers. They are commonly used, and the costs of providing each service are readily allocated to the service with a unit rate.

The following services are currently provided in relation to distribution supply points at which gas is withdrawn by or in respect of a residential customer:

- **Meter and Gas Installation Test**: On-site testing to check the accuracy of a meter (in measuring the quantity of gas delivered) and the soundness of a gas installation.
- **Disconnection Service**: Disconnection by the carrying out of work being:
  - Removal of the meter at a metering installation, or
  - The use of locks or plugs at a metering installation to prevent the withdrawal of gas at the distribution supply point.
- **Reconnection Service**: Reconnection by turning on supply, including the removal of locks or plugs used to isolate supply or reinstallation of a meter if it has been removed, performance of a safety check and the lighting of appliances where necessary.
- **Special Meter Reading Service**: Meter reading for a distribution supply point in addition to the scheduled meter readings that form part of the Haulage Reference Services.

We are also proposing three new ancillary reference services in the forthcoming access arrangement period. These three new services are in moderate to high demand and are generally not substitutable with other services:

- **Meter Fix or Reinstallation**: Reinstallation of a meter at a metering installation, performance of a safety check and the lighting of appliances where necessary.
- **Meter and Service Removal**: Removal of a meter and service line to prevent the withdrawal of natural gas at the delivery point.
- **Minor Meter Alter Position**: Relocating an existing gas meter to a new position, within 4 meters of the original meter, in a single site visit.

These three services were described in more detail in our approved reference service proposal, where we established that they are consistent with the reference service factors. They are used by significant numbers of customers, allows for more streamlined service delivery, not substitutable with other reference services, would be useful to inform non-reference service negotiations and have largely predictable costs.

In expanding our range of reference services, we are providing our customers with greater cost transparency and avoiding delays in obtaining bespoke quotations for services that have generally predictable costs.

16. Price control mechanism

16.1. Key points

- We are proposing to:
  - Continue to use the tariff basket form of price control in the forthcoming access arrangement period.
  - Retain the AER's approved weighted average price cap (WAPC) formula, except for a change to incorporate a License Fee factor within the formula.
- The transition to financial year regulatory years has also required adjustments to the form of control. We have, therefore, proposed changes to the CPI used (moving from a June Quarter to a December Quarter) and the calculation of the trailing cost of debt.
- Our price control mechanism is consistent with the requirements of the NGR that relate to the setting of prices.

16.2. Chapter structure

The remainder of this chapter is structured:

- Section 16.3 provide summary information on control mechanism.
- Section 16.4 sets out the proposed price control formula, rebalancing arrangements and tariff variation process for Haulage Reference Services.
- Section 16.5 sets out the equivalent information for Ancillary Reference Services.

16.3. Control mechanism

The Price Control Mechanism is how our prices are set and vary across the access arrangement period.

The NGR explains how we must set our prices over the course of an access arrangement period as well as provide a rationale for any proposed reference tariff variation mechanism.[132] The NGR also outlines information on the mechanics of reference tariff variation.[133]

In preparing our price control mechanisms we have, therefore, adhered to the requirements outlined in the NGR.

16.4. Tariff variation for haulage services

16.4.1. Price control formula

We are proposing to continue to use the tariff basket form of price control in the forthcoming access arrangement period.[134] This approach has been applied to the Victorian distribution gas network for four successive access arrangement periods and is appropriate as:

- It relies on actual t-2 quantities, as opposed to estimated quantities, which reduces the administrative costs to all parties.

[132] See Rule 92 and Rule 72(1)(k).
[133] See Rule 97.
[134] This is consistent with rule 97(2)(b).

- It allows us to:
  - adjust tariffs within period to ensure tariffs remain at cost reflective levels, thus enabling the maintenance of tariffs that are consistent with the NGR and the NGO; and
  - allows us to recover our efficient and prudent costs.

We are proposing to modify the price control formula and introduce a Licence Fee Factor (L_t). While the Licence Fee Factor was removed from the price control formula for the 2018-23 GAAR, we consider it appropriate that this be re-introduced as:

- We have little or no ability to control this cost and, as demonstrated in the 2018-23 access arrangement period, the ESV levies escalated significantly quicker than anticipated.
- It is consistent with the treatment of ESV levies in the electricity distribution sector where the exact levies are recovered as a jurisdictional scheme amount in the control mechanisms formula.
- The alternative is recovering it through the opex forecast as a step change which naturally comes with some forecasting errors. This is a sub-optimal outcome when there is a process that allows the exact amount to be recovered - no more and no less.
- It ensures a greater level of transparency (and returns to an approach previously adopted in previous access arrangements).

Other than the changes outlined above, we have only looked to update the price control formulas to account for the transition from calendar years to financial years.

The price control formula which we are proposing (and which maintains consistency with the current arrangements in Victoria) is therefore:

$$(1+\Delta CPI_t)(1-X_t)(1+L_t)(1+PT_t) \geq \frac{\sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{ij} q_{t-2}^{ij}}{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{t-1}^{ij} q_{t-2}^{ij}}$$

where the Service Provider has n Haulage Reference Tariff categories, each category having up to *m* Haulage Reference Tariff Components and where:

ΔCPI_t	is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in Regulatory Year *t*-2 to the December quarter in Regulatory Year *t*-1, calculated using the following method:
	The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in Regulatory Year *t*-1 divided by the ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in Regulatory Year *t*-2 minus 1.
	If the ABS does not, or ceases to, publish the index, then CPI will mean an index which the Regulator considers is the best available alternative index.
t	is the Regulatory Year for which tariffs are being set.
X_t	is the X factor for each year of the Sixth Access Arrangement Period as determined in the PTRM as approved in the full access arrangement decision, and annually revised for the Return on Debt Update calculated for the relevant year in accordance with that approved in the full access arrangement decision.
L_t	is the Licence Fee Factor for Regulatory Year *t*, as defined below.
PT_t	is the cost pass through adjustment factor for Regulatory Year *t* as calculated in accordance with clause 3.1.3.
n	is the number of different Haulage Reference Tariffs.
m	is the different components, elements or variables ("components") comprised within a Haulage Reference Tariff.
p_t^{ij}	is the proposed component *j* of Haulage Reference Tariff *i* in Regulatory Year *t*.
p_{t-1}^{ij}	is the prevailing component *j* of Haulage Reference Tariff *i* in Regulatory Year *t*-1.
q_{t-2}^{ij}	is the audited Quantity of Haulage Reference Tariff Component *j* of Haulage Reference Tariff *i* that was sold in Regulatory Year *t*-2.

The Licence Fee Factor is:

L is the Licence Fee pass through adjustment to the Distribution price control in Regulatory Year t for the Service Provider as determined below. For the purpose of this formula Licence Fee includes annual fees paid to Energy Safe Victoria.

Calculation of the Licence Fee factor:

The Licence Fee Factor pass through adjustment L_t, for the Service Provider is:

$$1 + L_t = \frac{(1 + L'_t)}{(1 + L'_{t-1})}$$

where:

If Regulatory Year t is 2023-24:

$$L'_t = \frac{lf_{t-1}(1 + pretaxWACC_D)^{3/2}(1 + CPI_t)^{3/2}}{(1 + CPI_t)(1 - X_t)(1 + PT_t)(1 - PT_{t-1})\sum_{i=1}^{n}\sum_{j=1}^{m} p_{t-1}^{ij} q_{t-2}^{ij}}$$

If Regulatory Year t is 2024-25 to 2027-28:

$$L'_t = \frac{lf_{t-1}(1 + pretaxWACC_D)^{3/2}(1 + CPI_t)^{3/2}}{(1 + CPI_t)(1 - X_t)(1 + PT_t)\sum_{i=1}^{n}\sum_{j=1}^{m} p_{t-1}^{ij} q_{t-2}^{ij}}$$

$\boldsymbol{L'_{t-1}}$	(a) if Regulatory Year t is the Regulatory Year ending 30 June 2024, the Licence Fee in the final year of the previous Access Arrangement Period; and (b) if Regulatory Year t is after the Regulatory Year ending 30 June 2024, is the value of the $\boldsymbol{L'_t}$ determined in Regulatory Year t-1.
$\boldsymbol{lf_{t-1}}$	is the Licence Fee paid by the Service Provider for the Financial Year ending June of the Regulatory Year t-1

16.4.1.1. Return on Debt Update

The Return on Debt Update is the update to the annual return on debt component of the rate of return included in the PTRM at the time the Regulator made its final decision for the Sixth Access Arrangement Period and is determined in accordance with paragraphs (b) to (e) of this clause 3.1.2. The Averaging Period for each Financial Year of the Sixth Access Arrangement Period must be used for the purposes of calculating the annual return on debt observation for that year.

16.4.1.2. Calculating the return on debt

The annual update of the return on debt component of the rate of return in each Regulatory Year of the Sixth Access Arrangement Period, starting from 1 July 2023, is to be calculated as follows:

For Regulatory Year 2023-24: $kd_{2023-24} = (0.45 \cdot R_{2018}) + (0.1 \cdot R_{2019}) + (0.1 \cdot R_{2020}) + (0.1 \cdot R_{2021}) + (0.1 \cdot R_{2022}) + (0.05 \cdot R_{HY2023}) + (0.1 \cdot R_{2023-24})$

For Regulatory Year 2024-25: $kd_{2023-24} = (0.35 \cdot R_{2018}) + (0.1 \cdot R_{2019}) + (0.1 \cdot R_{2020}) + (0.1 \cdot R_{2021}) + (0.1 \cdot R_{2022}) + (0.05 \cdot R_{HY2023}) + (0.1 \cdot R_{2023-24}) + (0.1 \cdot R_{2024-25})$

For Regulatory Year 2025-26: $kd_{2023-24} = (0.25 \cdot R_{2018}) + (0.1 \cdot R_{2019}) + (0.1 \cdot R_{2020}) + (0.1 \cdot R_{2021}) + (0.1 \cdot R_{2022}) + (0.05 \cdot R_{HY2023}) + (0.1 \cdot R_{2023-24}) + (0.1 \cdot R_{2024-25}) + (0.1 \cdot R_{2025-26})$

For Regulatory Year 2026-27: $kd_{2023-24} = (0.15 \cdot R_{2018}) + (0.1 \cdot R_{2019}) + (0.1 \cdot R_{2020}) + (0.1 \cdot R_{2021}) + (0.1 \cdot R_{2022}) + (0.05 \cdot R_{HY2023}) + (0.1 \cdot R_{2023-24}) + (0.1 \cdot R_{2024-25}) + (0.1 \cdot R_{2025-26}) + (0.1 \cdot R_{2026-27})$

For Regulatory Year 2027-28: $kd_{2023-24} = (0.05 \cdot R_{2018}) + (0.1 \cdot R_{2019}) + (0.1 \cdot R_{2020}) + (0.1 \cdot R_{2021}) + (0.1 \cdot R_{2022}) + (0.05 \cdot R_{HY2023}) + (0.1 \cdot R_{2023-24}) + (0.1 \cdot R_{2024-25}) + (0.1 \cdot R_{2025-26}) + (0.1 \cdot R_{2026-27}) + (0.1 \cdot R_{2027-28})$

where:

$\boldsymbol{kd_t}$	is the annual return on debt for Regulatory Year *t* of the Sixth Access Arrangement period.
$\boldsymbol{R_t}$	is the annual return on debt observation for each Regulatory Year *t* of the Sixth Access Arrangement period calculated in accordance with paragraph (c) below, other than Regulatory Year 2023-24. For Regulatory Year 2018, $R_{2023-24}$ is 5.04 per cent.

(c) Calculation of the annual return on debt observation

(1) Overview

(A) The return on debt observation for each Regulatory Year is calculated by automatic application of the following formula. This requires three steps:

Step 1: Calculate the adjusted RBA estimate.

Step 2: Calculate the adjusted BVAL estimate.

Step 3: Calculate the final estimate, where the RBA and BVAL estimates are combined using an arithmetic average.

(B) The steps in paragraph (c)(1) reflect the approach used by the Regulator to determine the return on debt included in the PTRM at the time the Regulator made its final decision for the Sixth Access Arrangement Period. In the event that data availability changes during the Access Arrangement Period, the formula below will change to reflect the contingencies set out in the Regulator's final decision for the Sixth Access Arrangement Period.

(C) For the purpose of this clause 3.1.2(c) only, a business day means a day other than a Saturday, Sunday or a day recognised as a national public holiday or a public holiday in NSW.

(2) Calculating the adjusted RBA estimate

To calculate the adjusted RBA estimate in Step 1:

(A) Download RBA table F3—'Aggregate measures of Australian Corporate Bond Spreads and Yields' from the RBA website.

(B) From this file, download the 7 and 10 year 'Non-financial corporate BBB-rated bonds—Yield' entries for dates:

(i) from the most recent published RBA date prior to the commencement of the nominated Averaging Period for debt;

(ii) to the first published RBA date following the conclusion of the nominated Averaging Period for debt; and

(iii) all published dates between (i) and (ii).

(C) Download, from RBA table F16—'Indicative Mid Rates of Australian Government Securities', daily yields on CGSs for dates within the Service Provider's Averaging Period.

(D) Linearly interpolate between the two nearest bonds straddling 7 years remaining term to maturity, and the two nearest CGS bonds straddling 10 years remaining term to maturity. This is to be done using the following formula:

- $$Yield_{interpoltated} = Yield_{lower\ straddle\ bond} + \left[\left(Yield_{upper\ straddle\ bond} - Yield_{lower\ straddle\ bond}\right) \times \left(Date_{10\ years\ from\ interpolation\ date} - Maturity\ Date_{lower\ straddle\ bond}\right) \div \left(Maturity\ Date_{upper\ straddle\ bond} - Maturity\ Date_{lower\ straddle\ bond}\right)\right]$$

(E) Linearly extrapolate the published RBA 10 year yield (from paragraph (c)(2)(B)) from its published effective term to an effective term of 10 years using the formula below:

$$Yield_{10} = Yield_{10\ year\ published} + \left[\left(Spread\ to\ Swap_{10\ year\ published} - Spread\ to\ Swap_{7\ year\ published}\right) \div \left(Effective\ Term_{10\ year\ published} - Effective\ Term_{7\ year\ published}\right) \times \left(10 - Effective\ Term_{10\ year\ published}\right)\right]$$

(F) Linearly extrapolate the published RBA 7 year yield (from paragraph (c)(2)(B)) from its published effective term to an effective term of 7 years using the formula below:

- $$Yield_{7} = Yield_{7\ year\ published} + \left[\left(Spread\ to\ Swap_{10\ year\ published} - Spread\ to\ Swap_{7\ year\ published}\right) \div \left(Effective\ Term_{10\ year\ published} - Effective\ Term_{7\ year\ published}\right) \times \left(7 - Effective\ Term_{7\ year\ published}\right)\right].$$

(G) Subtract from the extrapolated 10 year RBA yield on each publication date the interpolated CGS yield on that date. For the 10 year term, use the RBA series as adjusted in paragraph (c)(2)(E). **These are the adjusted RBA 10 year spreads**.

(H) Obtain daily RBA spread estimates by linear interpolation of the adjusted RBA spreads (from paragraphs (c)(2)(E) and (F)) for both 7 and 10 year terms between the published dates identified in paragraph (c)(2)(B). Use the adjusted RBA spread estimates as calculated in paragraph (c)(2)(D). This is to be done using the following formula:

- $Spread_{interpolated} = Spread_{first\ straddling\ publication\ date} + [(Date_{interpolation} - Date_{first\ straddling\ publication\ date}) \times (Spread_{second\ straddling\ publication\ date} - Spread_{first\ straddling\ publication\ date}) \div (Date_{second\ straddling\ publication\ date} - Date_{first\ straddling\ publication\ date})]$

If the annual return on debt estimate must be finalised before a final published RBA month-end estimate is available, hold the last observed RBA spread constant to the end of the Averaging Period.

(I) Add to the daily spreads (from paragraph (c)(2)G)), daily interpolated estimates of the CGS (from paragraph (c)(2)(D)) for all business days in the Service Provider's Averaging Period. Specifically:

(i) add the 7 year interpolated CGS estimates to the 7 year interpolated RBA spreads. These are the **interpolated RBA daily 7-year yield estimates**;

(ii) add the 10 year interpolated CGS estimate to the 10 year interpolated RBA spread. These are the **interpolated RBA daily 10-year yield estimates.**

(J) Convert the interpolated RBA daily 7-year yield estimates and the interpolated RBA daily 10-year yield estimates (from paragraph (c)(2)(I)) to effective annual rates, using the formula:

$$Effective\ annual\ rate = \left(\left(1 + \frac{yield}{200}\right)^2 - 1\right) \cdot 100$$

(K) Average the yield estimate for the 10 year RBA yield estimate over all business days in the Service Provider's Averaging Period. This is the adjusted RBA estimate.

(3) Calculating the adjusted BVAL estimate

To calculate the adjusted BVAL estimate in Step 2:

(A) For dates after 14 April 2015, download the 10 year Corporate BBB rated Australian BVAL curve (BVCSAB10). For dates before 14 April 2015, download from Bloomberg the 7 year Corporate BBB rated Australian BVAL curve (BVCSAB07 index) for all business days in the Service Provider's Averaging Period.

(B) For dates before 14 April 2015, add to the 7 year yield the difference between the 7 and 10 year daily RBA adjusted yields (as calculated in viii) of the RBA process). This is the **extrapolated daily estimate of the BVAL 10 year yield**.

(C) For all dates, convert the 10 year yields into effective annual rates, using the formula:

$$Effective\ annual\ rate = \left(\left(1 + \frac{yield}{200}\right)^2 - 1\right) \cdot 100$$

(D) Average the extrapolated daily estimates of the BVAL 10 year yield over all business days in the service provider's Averaging Period. This is the **adjusted BVAL estimate**.

(4) Calculating the annual estimate of the return on debt

To calculate the final estimate in Step 3:

(A) Take the simple average of the adjusted RBA estimate (from paragraph (c)(2)(K)) and the adjusted BVAL estimate (from paragraph (c)(3)(D)). This is the **annual estimate of the return on debt**.

(d) Annual return on debt observation where relevant data not available

For any Regulatory Year of the Sixth Access Arrangement period (other than Regulatory Year 2023-24) for which an annual return on debt observation cannot be calculated in accordance with paragraph (c) above due to changes in data availability, adjust the approach in accordance with the contingencies set out in the Regulator's final decision for the Sixth Access Arrangement period.

(e) Notification and Regulator's determination of the annual return on debt observation

(1) The Regulator will notify the Service Provider of the updated Return on Debt and X factor within 15 Business Days after the end of the Service Provider's Averaging Period.

(2) In the 'PTRM input' sheet of the PTRM, update the relevant cell for the updated return on debt estimate (kd_t). This is:

For Regulatory Year 2023-24:	$kd_{2023-24}$	Cell G222
For Regulatory Year 2024-25:	$kd_{2024-25}$	Cell H222
For Regulatory Year 2025-26:	$kd_{2025-26}$	Cell I222
For Regulatory Year 2026-27:	$kd_{2026-27}$	Cell J222
For Regulatory Year 2027-28:	$kd_{2027-28}$	Cell K222

(3) On the 'X factors' sheet of the PTRM, update the relevant X factor for each of the following Regulatory Years as follows:

For Regulatory Year 2024-25:	$kd_{2024-25}$	Select 'Set X2 (price cap)'
For Regulatory Year 2025-26:	$kd_{2025-26}$	Select 'Set X3 (price cap)'
For Regulatory Year 2026-27:	$kd_{2026-27}$	Select 'Set X4 (price cap)'
For Regulatory Year 2027-28:	$kd_{2026-27}$	Select 'Set X5 (price cap)'.

16.4.1.3. Pass Through Adjustment Factor

(a) Pass Through Adjustment Factor

PT_t is the pass through adjustment to the Distribution price control in Financial Year t for the Service Provider and is determined in accordance with paragraph (b) below.

(b) Calculation of the Adjustment Factor

$$PT_t = \frac{(1 + PT'_t)}{(1 + PT'_{t-1})} - 1$$

where:

t is the year for which tariffs are being set

PT'_{t-1} is:

(a) zero when Financial Year t-1 refers to Financial Year ending 31 December 2023;

(b) the value of PT't determined in the Financial Year t-1 for all other Financial Years in the Access Arrangement Period;

PT'_t equals:

$$PT'_t = \frac{AP_t}{(1 + \Delta CP1_t)(1 - X_t)\sum_{i=1}^{n}\sum_{j=1}^{m} p_{t-1}^{ij} q_{t-2}^{ij}}$$

$\boldsymbol{AP_t}$	is (a) any determined pass through amount that the Regulator approves in whole or in part in Regulatory Year *t*; and/or (b) any pass through amounts arising from any Relevant Pass Through Events (as that term is defined in the Access Arrangement applying to the Service Provider in the Fifth Access Arrangement Period) occurring in the Fifth Access Arrangement Period that the Service Provider proposed to pass through in whole or in part in Regulatory Year *t*, that includes an amount to reflect the time value of money between incurring the costs and recovering the costs, and excludes any amounts already passed through in Haulage Reference Tariffs.
$\boldsymbol{\Delta CPI_t}$	is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in Regulatory Year *t*-2 to the December quarter in Regulatory Year *t*-1, calculated using the following method: The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in Regulatory Year *t*-1 divided by

	the ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in Regulatory Year *t*-2 minus 1. If the ABS does not, or ceases to, publish the index, then CPI will mean an index which the Regulator considers is the best available alternative index.
X_t	is the X factor for each Regulatory Year of the Sixth Access Arrangement Period as determined in the PTRM as approved in the full access arrangement decision, and annually revised for the Return on Debt Update calculated for the relevant year during the Sixth Access Arrangement Period in accordance with that approved in the full access arrangement decision.
p^{ij}_{t-1}	is the prevailing component *j* of Haulage Reference Tariff *i* in Regulatory Year *t*-1.
q^{ij}_{t-2}	is the Quantity of component *j* of Haulage Reference Tariff *i* that was sold in Regulatory Year *t*-2.

16.4.2. Rebalancing constraint

In contrast to the National Electricity Rules, which codifies a 2% rebalancing constraint, Rule 97 of the NGR sets out broad provisions pertaining to the tariff variation mechanism.

In the 2013 GAAR, we initially proposed a rebalancing constraint of 5%. The AER set out its reasoning for preferring a lower constraint of 2% as follows:

> *The AER agrees that increasing the rebalancing constraint would provide greater flexibility to change prices which could be used to achieve greater cost reflectivity. However, it is not apparent that the current balancing constraint of two per cent has materially inhibited SP AusNet's ability to achieve cost reflective pricing in previous regulatory periods. In addition, a higher rebalancing constraint could lead to increased price volatility and potential price shocks to customers within the regulatory period. This would create uncertainty for downstream users which, in turn, may be detrimental to the efficient investment in and utilisation of pipeline assets. The AER considers that a reference tariff control should preferably result in a price path with a reasonable degree of certainty and predictability.*[135]

We accepted the AER's preference for a 2% rebalancing constraint to be applied at the tariff component level for years 2-5 of the period. For the forthcoming access arrangement period, we propose to maintain this rebalancing constraint, consistent with the AER's reasoning in the 2013 GAAR. We reiterate our earlier view that flexibility in tariff setting is essential if tariffs are to be cost reflective in accordance with the NGO.

16.4.3. Tariff variation proposal

Consistent with the existing access arrangement, AusNet will, at least 50 Business Days prior to the commencement of the next Regulatory Year, submit proposed Haulage Reference Tariffs to apply from the start of the next Regulatory Year for verification of compliance by the Regulator, in accordance with clauses 4.2(a), (b), (c) and (d) of Part B of our access arrangement. Particularly:

- AusNet will ensure its proposed Haulage Reference Tariffs or proposed changes to Haulage Reference Tariffs submitted comply with the Tariff Control Formula and Rebalancing Control Formula.
- Where the AusNet proposes to introduce a new Haulage Reference Tariff or new Haulage Reference Tariff Component or withdraw an existing Haulage Reference Tariff or existing Haulage Reference Tariff Component within a Regulatory Year it will submit the proposal for verification of compliance by the Regulator.

16.5. Tariff variation for ancillary services

From 1 July 2024, the Service Provider will make annual adjustments to the Ancillary Reference Tariffs in accordance with the formulae below. For the avoidance of doubt, Ancillary Reference Tariffs are not adjusted in accordance with the Tariff Control Formula or rebalancing control formula in clause 3.

The Ancillary Reference Tariff Control Formula for the Regulatory Year 2024-25 to Year 2027-28 is:

(a) From 1 July 2024 the Service Provider will make annual adjustments to the Ancillary Reference Tariffs in accordance with the formulae below. For the avoidance of doubt, Ancillary Reference Tariffs are not adjusted in accordance with the Tariff Control Formula or rebalancing control formula in clause 3.

[135] AER, Access Arrangement draft decision SPI Networks (Gas) Pty Ltd 2013–17, Part 2 Attachments, September 2012, p. 326.

(b) The Ancillary Reference Tariff Control Formula for the Regulatory Year 2024-25 to Year 2027-28 is:

$$ART_t = ART_{t-1} \times (1 + \Delta CPI_t)$$

where:

$\boldsymbol{ART_t}$	is the Ancillary Reference Tariff that applies in Regulatory Year *t*.	
$\boldsymbol{ART_{t-1}}$	is the Ancillary Reference Tariff that applies in Regulatory Year *t*-1.	
$\boldsymbol{\Delta CPI_t}$	is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in Regulatory Year *t*-2 to the December quarter in Regulatory Year *t*-1, calculated using the following method:	
		The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in Regulatory Year *t*-1 divided by the ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in Regulatory Year *t*-2 minus 1.
	If the ABS does not, or ceases to, publish the index, then CPI will mean an index which the Regulator considers is the best available alternative index.	

16.5.1. Rebalancing constraint

Given that it is proposed that Ancillary Reference Services are to be escalated by CPI annually, we do not propose to adopt a rebalancing constraint for Ancillary Reference Services.

16.5.2. Tariff variation proposal

We propose that this be applied in the same manner as for Haulage Reference Services, as outlined in section 16.4.3 above.

17. Reference tariffs

17.1. Key points

- We are proposing to retain the existing tariff classes, tariff structures and pricing zones for the forthcoming access arrangement period.
- All our proposed tariff structures and levels are consistent with the NGR. In particular, our tariff revenues sit between the stand alone and avoidable cost of supply. In addition, our tariffs and charging parameters take into account the long run marginal costs (LRMC) of supply.

17.2. Chapter structure

The remainder of this chapter is structured as follows:

- Section 17.3 provides an overview of the reference tariff framework.
- Section 17.4 describes our approach to cost allocation and tariff setting.
- Section 17.5 outlines our interpretation of the pricing principles set out in the NGR and describes our methodology for estimating the LRMC, and stand alone and avoidable costs.
- Section 17.6 describes our proposed tariffs and explains why they comply with the NGR.

17.3. Overview of the reference tariff framework

The NGR requirements relating to reference tariffs and our cost allocation approach are outlined in Rules 72(1), 93 and 94. In summary:

- Rule 72(1) (j) and (k) requires us to provide information about our proposed approach to tariff setting, including the method used to allocate costs and a demonstration of the relationship between costs and tariffs, and to explain the rationale for our reference tariff variation mechanism.
- Rule 93 governs the allocation of total revenue and costs, including requiring that any costs directly attributable to reference services should be allocated to those services.
- Rule 94 sets out provisions relating to tariffs for distribution pipelines, including that:
  - Customers for reference services are to be divided into different tariff classes.
  - The revenue collected from each class of customer should lie on or between the cost of providing those services and the avoidable cost of not providing those services.
  - Tariffs must take into account the LRMC of providing the reference service or charging parameter.

17.4. Cost allocation and tariff setting

To meet the cost allocation requirements of Rules 93 and 94, we have applied the following broad principles:

- Wherever possible, operating costs are directly attributed to assets and distribution service categories where the cost is directly related to the management (for example, the operation, maintenance and construction) of the asset or the delivery of the service. In other words, where there is a clear 'line of sight' between the costs incurred and the particular assets and/or service, those costs are directly attributed to those assets and/or service categories. These cost allocations are set out in our annual regulatory accounts.
- We directly attribute costs in our regulatory accounts to:
  - Haulage Reference Services.
  - Ancillary Reference Services.
  - Pipeline Services that are not Reference Services.
- We allocate costs between the tariffs for Haulage Reference Services according to the relevant cost drivers, such as load factor. For example, business customers' usage profiles indicate that these customers' use peak gas at only 1.48 times the rate of off peak gas, while residential customers' peak usage is 3.01 times off peak. Accordingly, we are proposing a lower peak and off-peak charge for business customers to reflect differences in load factor.
- Costs incurred in the provision of Ancillary Reference Services are included in the building block calculation. Tariffs for Ancillary Reference Services are based on the incremental cost of providing those services, including a small overhead cost to cover administration. These tariffs are charged to those customers that request the service.
- Costs associated with non-reference services are set out in the regulatory accounts but are not included in the building block costs. These services are not required by a large part of the market and the scope of the services offered tends to vary significantly. For these reasons, we recover the costs of these services on a recoverable works basis. Therefore, the cost of providing these services is recovered only from those customers who request the service (and not from Haulage Reference Service or Ancillary Reference Service customers).

17.5. Pricing principles

Based on the requirements of Rules 93 and 94, we developed and applied our own pricing principles to guide the development of our reference tariffs. The primary objective is to ensure our reference tariff structures are efficient, which means that:

(5) A reference tariff should encourage consumers to consume gas up to the point where the marginal benefit to them of consuming an additional gigajoule of gas equals the marginal cost of providing that extra gigajoule of gas to that customer.

(6) A reference tariff should not encourage customers to:
  - disconnect from the network, or seek to bypass the existing network, when the cost of providing the service is less than their willingness to pay for gas services; and
  - consume gas, when the value that they place on that consumption is less than the avoidable cost of distributing that gas to them.

(7) A reference tariff should be administratively simple, in that customers should be able to readily understand it and should be able to respond to price signals.

The first two points relates to LRMC, stand alone and avoidable costs, and are discussed below. Tariff design, which relates to the third element, is discussed in section 176.6.

17.5.1. Long run marginal cost (LRMC)

We have used the Average Incremental Cost (AIC) approach to determine the LRMC given its suitability to situations where there is a reasonably consistent profile of investment over time to service growth in demand.

The AIC approach uses the following formula to determine the LRMC:

$$LRMC = \frac{\sum NPV(growth\ related\ shared\ network\ capex\ and\ opex)}{\sum NPV\ (incremental\ demand)}$$

In applying the AIC approach to derive the LRMC we note:

(8) The costs that are shared by tariff customers, typically being 'shared network assets' and their associated opex will be included in the calculation.

(9) The LRMC at peak times exceeds the LRMC for off peak periods, reflecting the cost drivers in the model.

(10) Relevant capital costs are split between domestic and non-domestic customer classes based on their relative contribution to the forecast increases in maximum daily quantity (MDQ) in each tariff zone, which in turn is the underlying driver of capital augmentations.

The results of our LRMC analysis are outlined in the tables below.

Table 17.1: LRMC results – Domestic

Pricing zone	Peak ($/GJ)	Off peak ($/GJ)
Central	$1.2733	$0.0698
West	$1.2942	$0.0710
Adjoining Central	$1.2024	$0.0658
Adjoining West	$1.3226	$0.0726

Source: AusNet

Table 17.2: LRMC results – Non-Domestic

Pricing zone	Peak ($/GJ)	Off peak ($/GJ)
Central	$0.2111	$0.0031
West	$0.0250	$0.0004
Adjoining Central	$0.0052	$0.0001
Adjoining West	$0.0059	$0.0001

Source: AusNet

While we regard the above LRMC estimates as reasonable, the calculations are sensitive to input assumptions. Therefore, they should be regarded as indicative only.

17.5.2. Stand alone and avoidable costs

For each tariff class, the revenue expected to be recovered should lie on or between:

- An upper bound representing the stand alone cost of providing the reference service.
- A lower bound representing the avoidable cost of not providing the reference service to those customers.

Where revenue falls in that band from a class of customers, it is commonly known as the 'efficient pricing band'. Prices within this 'band' are considered efficient because:

- If the price is less than the stand alone cost – customers are not paying more than the costs of a dedicated network to serve their requirements. If revenues exceed this level, customers will prefer to bypass the existing network.
- If the price is greater than the avoidable cost – customers are (at a minimum) meeting the additional costs incurred in providing the service. If revenues were below this level, customers would be receiving a cross subsidy.

To estimate the stand alone cost of servicing a customer or group of customers, we focused on the cost that would lead customers within that tariff class to by-pass our network. We have used a bypass analysis to prepare our estimates as this allows us to consider the different options for small and large customers:

- Small Customers: Assessing the cost per gigajoule of utilising 'bottled gas', and comparing this to each of our proposed Tariff V tariffs.
- Large Customers: Estimate the bypass costs of connecting a customer to the existing transmission network, taking into account the location and size of existing connections. We adopted this approach for Tariff M and Tariff D customers.

We have considered that the avoidable costs of supply are best estimated by calculating the short run marginal costs of supply, and multiplying this cost by the estimated average usage.

The results of our analysis is summarised in the tables below.

Table 17.3: Small customers stand alone and avoidable cost results

Tariff class	Stand alone	Avoidable cost	Average revenue
Central – Domestic	$2,201	$604	$898
West – Domestic	$2,331	$508	$754
Adjoining Central – Domestic	$1,653	$706	$1,052
Adjoining West – Domestic	$2,440	$791	$1,177
Central – Non-domestic	$22,024	$1,037	$1,546
West – Non-domestic	$13,640	$645	$962
Adjoining Central – Non-domestic	$8,486	$1,669	$2,490
Adjoining West – Non-domestic	$16,723	$2,899	$4,326

Source: AusNet

Table 17.4: Large industrial customers stand alone and avoidable cost results

Tariff class	Stand alone	Avoidable cost	Average revenue
Tariff D – 0m from transmission with MHQ of 387 GJ/hr	$483 per MHQ	$162 per MHQ	$184 per MHQ
Tariff D – above the MHQ of 387 GJ/hr threshold	$913 - $389 per MHQ	$129 - $55 per MHQ	$184 per MHQ
Tariff M -0m from transmission assuming usage equivalent to citigate capacity of 387 GJ/hr	$483 per MHQ	$162 per MHQ	$239 per MHQ
Tariff M – 825m from transmission assuming average usage equivalent to citygate capacity of 387 GJ/hr	$487 per MHQ	$162 per MHQ	$239 per MHQ
Tariff M – 0m from transmission assuming largest Tariff M customers of 102 MHQ and citygate of 387 GJ/hr	$1,840 per MHQ	$162 per MHQ	$239 per MHQ

Source: AusNet

We tested the sensitivity of these results for maximum hourly quantities (MHQ) above 387GJ/hr to test whether the scale efficiency benefits that accrue from providing an increased capacity at the citygate would lead to the standalone cost being less than the revenue that is accrued via Tariff D charges. The analysis showed that even when utilising the largest MHQ exhibited by an individual customer on our network, the revenue generated from levying Tarff D charges is still below the standalone cost of supply, once the cost of connecting that customer to the transmission network, given their specific location, is taken into account. Specifically, the standalone cost, inclusive of connection assets to distribute gas to their location, ranges from $389 per MHQ to $913 per MHQ.

Our analysis also showed that a group of Tariff M customers that collectively used 387GJ/hr would need to be situated within 825m of the transmission network to make by-pass economic. We note that currently, none of our Tariff M customers are within this vicinity of the transmission network.

Having regard to the above, we therefore consider our tariffs comply with the NGR and, in particular, with Rule 94 (3).

17.6. Tariff design

The following section describes our proposed tariff design, including the relevant tariff classes that Rule 94(1) requires us to develop.

17.6.1. Tariff classes

We are proposing to retain our existing tariff classes and pricing zones for the forthcoming access arrangement period. We propose to have three tariff classes: V, D and M - each tariff of which is a sub component of a Haulage Reference Service. Our tariff classes and the geographic regions in which they apply are summarised in the table below.

Table 17.5: Tariff classes applicable to each Haulage Reference Services

Tariff V	Tariff D	Tariff M
Central – Domestic	Central – Demand	Central – Demand
West – Domestic	West – Demand	West – Demand
Adjoining Central – Domestic	Adjoining Central – Demand	Adjoining Central – Demand
Adjoining West – Domestic	Adjoining West – Demand	Adjoining West – Demand
Central – Non-domestic		
West – Non-domestic		
Adjoining Central – Non-domestic		
Adjoining West – Non-domestic		

Source: AusNet

The tariff parameters, which are common to each tariff class, reflect the key cost drivers:

- Anytime maximum demand
  - A customer's anytime maximum demand determines the size of their connection and the assets required for the provision of pipeline services.
- Location
  - We have grouped customers by location, to reflect the different regional costs of delivering gas.
- Contribution to overall system peak demand
  - Different customer classes will typically have different load factors across the year, which lead to different utilisation patterns of our asset base and cost of service. In the absence of more sophisticated metering arrangements, it is efficient to group customers into different classes based on their expected load factor.
  - We have created two classes, domestic and non-domestic, which typically exhibit quite different load factors. This approach promotes efficient pricing by ensuring that tariffs are cost reflective.

Our proposed tariff classes avoid unnecessary transaction costs in accordance with Rule 94. In particular, the tariff definitions readily allow customers to be allocated to the appropriate tariff.

Tariff V Haulage Reference Services

The Tariff V tariffs apply to both domestic and small to medium sized non-domestic customers. Each has a fixed and variable component. The variable component has a declining block structure that is driven by level of gas consumption (measured in GJ). Table 17. shows that the revenue that will be generated from each tariff class is between the stand alone, and avoidable cost of supply, indicating that our proposed tariffs comply with Rule 94(3).

We propose to maintain volumetric charges, primarily because existing metering arrangements do not allow charging arrangements for Tariff V customers to be based on a customer's peak demand. While the fixed charge is higher for non-domestic compared to domestic customers, this partly reflects the fact that the gigajoule tariff is lower. The lower gigajoule tariff is consistent with the flatter load profile for commercial customers, and their more limited contribution to peak demand (which drives network investment).

Tariff M Haulage Reference Services

Tariff M applies to customers who consume 10,000 Gigajoules of gas in a 12-month period or more than 10 Gigajoules in any hour. Tariff M customers are not required to pay any additional charges for operations and maintenance (O&M) or local capacity charge (LCC) as these have been embedded in the tariff.

Tariff charges are applied to the MHQ recorded for the calendar year in declining blocks. Once a customer's MHQ exceeds the first block the second block rate is applied to incremental MHQ until that block is exceeded and the third block rate applied to the balance. When a customer records an MHQ that is greater than that in any prior month of the tariff year, the excess amount is retrospectively applied to all prior months for that year. This charging approach ensures that customer receives a price signal that reflects the long run marginal costs of supply.

Tariff D Haulage Reference Services

The same charging arrangements for Tariff M customers applies to Tariff D except that:

- Tariff D customers pay an O&M charge which is an excluded service charge that recovers the cost of operating and maintaining mains extensions, services, metering and all other installation-related costs. O&M charges are levied on a per-month basis and apply to all Tariff D customers while they are connected to our distribution network.
- Tariff D customers pay an LCC charge prior to connection which is a non-reference service charge for providing connection assets and main extensions for a distribution supply point that a new tariff D customer is required to pay prior to connection being made.

17.6.2. Tariff structure and prices

We propose to maintain our existing tariff structure for both Haulage Reference Services and Ancillary Reference Services from the 2018-22 access arrangement period. The structures and proposed prices for each tariff are outlined in the following tables.

Table 17.6: Tariff V Haulage Reference Services

Central	Unit	Domestic	Non-domestic
Fixed charge	$/day	0.4319	0.4508
Peak 0 – 0.1	$/GJ	5.9493	1.0717
Peak > 0.1 – 0.2	$/GJ	3.5857	1.0210
Peak > 0.2 – 1.4	$/GJ	0.6234	0.9188
Peak > 1.4	$/GJ	0.5600	0.7014
Off peak 0 – 0.1	$/GJ	2.0166	1.0155
Off peak > 0.1 – 0.2	$/GJ	1.5936	0.7105
Off peak > 0.2 – 1.4	$/GJ	0.6108	0.5850
Off peak > 1.4	$/GJ	0.2166	0.5672

West	Unit	Domestic	Non-domestic
Fixed charge	$/day	0.4319	0.4508

Peak 0 – 0.1	$/GJ	3.1446	1.6379
Peak > 0.1 – 0.2	$/GJ	2.2643	1.3804
Peak > 0.2 – 1.4	$/GJ	0.7315	0.8528
Peak > 1.4	$/GJ	0.7011	0.3197
Off peak 0 – 0.1	$/GJ	0.9723	0.7590
Off peak > 0.1 – 0.2	$/GJ	0.9112	0.6394
Off peak > 0.2 – 1.4	$/GJ	0.5195	0.3081
Off peak > 1.4	$/GJ	0.1025	0.2292

Adjoining Central	Unit	Domestic	Non-domestic
Fixed charge	$/day	0.4319	0.4508
Peak 0 – 0.1	$/GJ	9.7431	4.0060
Peak > 0.1 – 0.2	$/GJ	7.0215	3.8174
Peak > 0.2 – 1.4	$/GJ	2.5010	3.6087
Peak > 1.4	$/GJ	2.3981	3.4084
Off peak 0 – 0.1	$/GJ	4.3634	3.6875
Off peak > 0.1 – 0.2	$/GJ	2.5305	3.5398
Off peak > 0.2 – 1.4	$/GJ	2.2018	3.4301
Off peak > 1.4	$/GJ	2.1174	3.3463

Adjoining West	Unit	Domestic	Non-domestic
Fixed charge	$/day	0.4319	0.4508
Peak 0 – 0.1	$/GJ	6.8274	4.9434
Peak > 0.1 – 0.2	$/GJ	5.7323	4.6402
Peak > 0.2 – 1.4	$/GJ	2.9419	3.9855
Peak > 1.4	$/GJ	2.6387	3.5033
Off peak 0 – 0.1	$/GJ	4.0516	3.8004
Off peak > 0.1 – 0.2	$/GJ	3.0641	3.6159
Off peak > 0.2 – 1.4	$/GJ	2.1940	3.1612
Off peak > 1.4	$/GJ	2.1253	3.0103

Source: AusNet

Table 17.7: Tariff M Haulage Reference Services

Blocks	Central	West	Adjoining Central	Adjoining West
0 – 10 MHQ (GJ/hr)	690.3145	690.3145	690.3145	690.3145
10 – 50 MHQ (GJ/hr)	657.4671	657.4671	657.4671	657.4671
>50 MHQ (GJ/hr)	137.2805	137.2805	137.2805	137.2805

Source: AusNet

Table 17.8: Tariff D Haulage Reference Services

Blocks	Central	West	Adjoining Central	Adjoining West
0 – 10 MHQ (GJ/hr)	314.9056	314.9056	314.9056	314.9056
10 – 50 MHQ (GJ/hr)	299.9126	299.9126	299.9126	299.9126
>50 MHQ (GJ/hr)	145.6113	145.6113	145.6113	145.6113

Table 17.9: Ancillary Reference Services

Ancillary reference services	2022-23 ($)
Meter & gas installation test	$198.40
Disconnection service	$66.13
Reconnection service	$66.13
Special meter reading service	$7.01
Meter fix or meter reinstallation	$141.62
Meter and service removal	$825.90
Minor meter alter position	$1005.81

Source: AusNet

17.6.3. Rules compliance

We have designed our proposed tariff structures and prices to ensure compliance with the NGR and the NGO. The principles we apply to allocate total revenue and costs are consistent our obligations under Rule 93(1) and (2). To ensure economically efficient pricing, we have developed tariff classes based on geographic location and consumption thresholds, and tested the expected revenues to be recovered against the stand alone and avoided cost of servicing these customers. Therefore, our reference tariffs comply with the requirements of Rule 94.

Finally, we have had regard to the NGO by:

- Incorporating peak and off-peak pricing in our domestic and non-domestic tariffs to reflect the higher costs to meet peak demand in the peak (winter) period.
- Set declining prices for higher consumption in our domestic and non-domestic tariffs. This is to reflect an environment where marginal costs of consumption are low and costs per customer do not increase in line with consumption.

18. Revisions to the Terms and Conditions of access

18.1. Key points

- The Access Arrangement comprises three parts which, together, constitute the terms and conditions on which we offer access to the gas distribution system:
  - Part A – which establishes a framework for the remainder of the Access Arrangement, and contains the schedule of ancillary reference services and the glossary.
  - Part B – Reference Tariffs and Reference Tariff Policy.
  - Part C – Terms and Conditions for access.
- We are proposing to amend each Part of the Access Arrangement as follows:
  - Administrative changes to Part A to reflect the commencement of a new access arrangement period, to update the pass through event definitions to align with those approved by the AER for our electricity distribution and transmission networks, and to make other changes as a consequence of changes to the gas regulatory framework and to reflect our proposed changes to Part C.
  - Administrative update Part B to reflect the commencement of a new access arrangement period.
  - Amend Part C to reflect changes recommended by stakeholders during our early consultation, and to make minor consequential changes to Part A. We are not proposing to change the credit support changes at this time.

18.2. Chapter structure

The remainder of this chapter is structured as follows:

- Section 17.3 provides information on the regulatory framework and our review approach.
- Section 17.4 outlines the rationale for the amendments we propose to make to each of Parts A, B and C of the Access Arrangement.

18.3. Regulatory framework and review approach

Rule 48(1)(d) requires that a full access arrangement must specify for each reference service the terms and conditions on which the reference service will be provided.

Rule 52 states:

> *(1) A service provider must, on or before the review submission date of an applicable access arrangement, submit an access arrangement revision proposal to the AER.*
>
> *(2) The access arrangement revision proposal must:*
>
> *(a) set out the amendments to the access arrangement that the service provider proposes for the ensuing access arrangement period; and*
>
> *(b) incorporate the text of the access arrangement in the revised form.*

We propose to offer our reference services in accordance with the terms and conditions set out in Part C of the access arrangement attached to this proposal. Included as part of the proposal is a version of the access arrangement which clearly identifies the changes proposed. The changes to Part C are also summarised below.

18.4. Rationale for proposed amendments

This section describes with more specificity the nature of the amendments we are proposing to make each Part of our Access Arrangement.

We have provided two versions of our proposed Access Arrangement for the forthcoming period to facilitate the AER's review and the public consultation process: a marked up version that shows the changes we propose to make in track changes, and a clean version, with no tracked changes.

18.4.1. Part A

The proposed amendments to Part A are for to update definitions to reflect jurisdictional changes and the commencement of a new access arrangement period, and to give effect to other parts of our proposal (such as our proposal to align the pass through event definitions with other gas and electricity distribution determinations). We do not expect these changes to be controversial on the basis that they will not materially change the operation of the Access Arrangement compared to the current approved access arrangement.

18.4.2. Part B – Reference Tariff and Reference Tariff Policy

The proposed amendments to Part B are for the purpose of:

- Reflecting the commencement of a new access arrangement period.
- Adjusting the:
  - Tariff formulae to reflect the shift from a calendar-based regulatory year to a July-June regulatory year.
  - Tariff control and rebalancing control formulae to reflect the recovery of ESV fees on an annual basis.
  - Return on debt formula to reflect the extension of the current access arrangement period by six months.
  - Billing periods and billing calculations for our demand tariffs to reflect the shift from a calendar-based regulatory year to a July-June regulatory year.
  - Incentive mechanisms applicable to the access arrangement period.
- Updating the postcodes to reflect the new postcodes that were added to our distribution area by virtue of an amendment our licence on 27 April 2022.

18.4.3. Part C -Terms and conditions

Part C of our proposed access arrangement has been amended to:

- Align the terms and conditions with the current NGR and retail market system B2B procedures.
- Ensure consistency with jurisdictional terminology and definitions.
- Reflect electronic means of communications (e.g., adding customer email address and customer mobile phone number, and removing facsimile as a means of notification).
- Re-locate our non-reference services charges from Schedule 3 of Part C to Appendix A of our Reference Service Proposal.
- Make other minor editorial amendments.

Through our engagement with the Stakeholder Roundtables and the Retailer Reference Group, we published a draft of Part C of our proposed access arrangement – the terms and conditions – for comment by interested parties and retailers. We received responses from three retailers. Their views, and our responses, are summarised in the below table.

Table 18.1: Amendments proposed by retailers

Issue	From	Description	Response
7.8 Credit support	Sumo & Simply Energy	Suggest the adoption of revised credit support provisions that reflect the NERL gas credit support regime to minimise costs to consumers.	AusNet proposes to retain our existing credit support arrangements on the basis that, unlike in jurisdictions where the NERL applies, we cannot recover losses from the failure of small to medium retailers. We would be supportive of the request to align with NERL jurisdictions, but only if the cost recovery provision also aligns with NERL jurisdictions and provided a zero threshold cost pass through event for a retailer failure in order to adequately mitigate the commercial risk to the network of retailer failure. Therefore, we do not consider the Access Arrangement is the appropriate regulatory instrument to make changes to the credit support framework.
7.4(d) Invoicing	AGL	AGL expects recovery for undercharged amounts to be limited to 4 months, to match the ERC requirements.	We acknowledge the recent changes to clause 70 of the now Energy Retail Code of Practice (**ERCOP**), whereby retailers are limited to recovering a small customer the consumption amount undercharged in the four months before the date the small customer is notified of the undercharging. However, adopting AGL's proposal would limit our ability to recover undercharged amounts from large customers for services provided more than 4 months prior to the date of the invoice. Further, we do not consider AGL's amendment is necessary because clause 7.4(d) already protects Users. It states that a User is "not obliged to pay [an] invoice to the extent that the User is precluded from recovering those costs from the relevant Customers by operation of Regulatory Instruments." Therefore, we do not propose to amend our access arrangement to adopt AGL's proposal.
9.4 Customer details	AGL	The T&Cs are quite specific about the provision of customer details. As this has now been made into a market transaction, AGL	We partially accept AGL's proposal, and have adopted a reference to the gas B2B Life Support Notification but retained a description of details of whether a customer needs life support

		suggests that this clause could be deleted (as it is now a required transaction in the Gas Market) or only refer to the transaction, which is governed by the Gas Market consultative process.	equipment and whether medical confirmation has been provided. However, we propose to retain the requirements that a retailer provide specific customer details. For the new data field, that was not previously required, we have made the requirement conditional on whether the information is available or changed. These details support our systems and processes. If the gas B2B transactions did not provide this information we would expect the details to be provided by another means, and retail market gas procedures may not be enforceable on their own.
9.5 New Distribution Supply Points	AGL	The T&Cs are quite specific about the provision of new supply points. As this has now been made into a market transaction, AGL suggests that this clause could be deleted (as it is now a required transaction in the Gas Market) or only refer to the transaction, which is governed by the Gas Market consultative process.	We propose retain our T&Cs requesting specific details on new distribution points of supply as our new supply points process has required this information for over a decade and unlikely to change over the forthcoming Access Arrangement period. Also, where the information is not provided in the gas market transaction we expect it to be provided in accompanying forms and emails.

19. Fixed principles

19.1. Key points

- We are proposing to retain the existing fixed principles and makes certain amendments to update those principles to allow for their continued application.

19.2. Chapter structure

The remainder of this chapter (Section 19.3) sets out the rationale for our proposed fixed principles.

19.3. Rationale for proposed fixed principles

A fixed principle provides regulatory certainty by preserving the AER's treatment of a particular issue or issues beyond the current access arrangement period. Rule 99 governs the use and effect of fixed principles:

(1) A full access arrangement may include a principle declared in the access arrangement to be fixed for a stated period.

(2) A principle may be fixed for a period extending over 2 or more access arrangement periods.

(3) A fixed principle approved before the commencement of these rules, or approved by the AER under these rules, is binding on the AER and the service provider for the period for which the principle is fixed.

(4) However:

(a) the AER may vary or revoke a fixed principle at any time with the service provider's consent; and

(b) if a rule is inconsistent with a fixed principle, the rule operates to the exclusion of the fixed principle.

The following fixed principles were approved by the AER for the current access arrangement period (being the Fifth Access Arrangement Period) and apply until either the end of the current access arrangement period or the forthcoming access arrangement period (being the Sixth Access Arrangement Period).

a) The Regulator will use incentive based regulation adopting a CPI - X approach and not rate of return regulation.

This fixed principle will apply until the end of the Fifth Access Arrangement Period.

(b) The Regulator will ensure that any mechanism for varying or adjusting the Haulage Reference Tariffs approved for the Fifth Access Arrangement Period will, to the extent required to give full effect to such variation or adjustment, be carried forward into the Sixth Access Arrangement Period.

This fixed principle will apply until the end of the Sixth Access Arrangement Period.

(c) Where a Relevant Pass Through Event occurs during an Access Arrangement Period but the impact of that Relevant Pass Through Event has not been fully recovered or reflected in adjusted Haulage Reference Tariffs and Haulage Reference Tariff Components prior to the end of that Access Arrangement Period, then the amount of the impact not fully recovered or reflected will be recovered or reflected in the next Access Arrangement Period by an adjustment to the Haulage Reference Tariffs and Haulage Reference Tariff Components for that next Access Arrangement Period.

This fixed principle will apply until the end of the Fifth Access Arrangement Period.

We consider it is appropriate to retain all the existing fixed principles and have proposed that each of the current principles remain in place for one further access arrangement period (to either the Sixth or Seventh Access Arrangement Period, as relevant). The rationale for retaining these fixed principles are:

- A continuation of the fixed principle relating to incentive based regulation will continue to promote the achievement of the NGO and ensure certainty for regulated service providers.
- In relation to the Haulage Reference Tariff adjustment, a continuation of this fixed principle will promote efficient pricing, which will further the achievement of the NGO to the benefit of consumers.
- In relation to the recovery of a Relevant Pass Through Event adjustment, continuation of this fixed principle will also promote efficient pricing, which will further the achievement of the NGO.

In summary, the continuation of these fixed principles will promote regulatory certainty and efficient outcomes in accordance with the NGO. We have, therefore, proposed some minor revisions to the principles to update the references to the forthcoming and subsequent Access Arrangement periods.

20. Other matters

20.1. Key points

- This chapter provides information on other matters a full access arrangement proposal must include.
- Our proposed policies for these other matters are largely unchanged from the policies currently in place.
- The matters raised in this chapter are reflected in our proposed amendments to Part A of our access arrangement for the 2024-2028 access arrangement period.

20.2. Chapter structure

The remainder of this chapter is structured:

- Section 20.3 sets out the submission date and review commencement date.
- Section 20.4 addresses our queuing policy.
- Section 20.5 identifies our approach to capacity trading.
- Section 20.6 outlines our extensions and expansion policy.
- Section 20.7 sets out our approach to the requirements regarding changes to receipt and delivery points.

20.3. Submission date and review commencement date

The NGR states that a full access arrangement (other than a voluntary access arrangement):

- Must contain a review submission date and a revision commencement date.
- Must not contain an expiry date.[136]

The NGR also stipulates that a service provider must propose a review submission date and a revision commencement date and if not approved the AER must set an alternative date.[137]

20.3.1. Proposed arrangements

We propose that the duration of the forthcoming access arrangement period be five years. Therefore, we propose that:

- The review submission date be 1 June 2027.
- The revision commencement date be 1 July 2028.

20.4. Queuing policy

Where an access arrangement contains queuing requirements, the NGR requires those requirements to be set out.[138]

[136] Rule 49.
[137] Rule 50.
[138] Rule 48(1)(e).

20.4.1. Proposed arrangements

Our queuing policy is set out in clause 5.5 of Part A of our proposed access arrangement. It states that requests for connection or modification of a connection are processed on a 'firstcome, first served' basis. Our proposed policy is unchanged from the policy currently in place.

20.5. Capacity trading

The NGR requires a full access arrangement to set out the capacity trading requirements on the pipeline and, where the service provider is registered as a participant in a particular gas market, for those requirements to be in accordance with rules or procedures governing that market.[139]

20.5.1. Proposed arrangements

We are not proposing to provide for capacity trading on our distribution network. This is in accordance with Part 19 of the NGR (Declared Wholesale Gas Market Rules) and Rule 105(1) of the NGR. Our proposed policy is unchanged from the policy currently in place.

20.6. Extension and expansion policy

The NGR requires that a full access arrangement set out its extension and expansion requirements and for those arrangements to meet specific requirements.[140]

20.6.1. Proposed arrangements

Our extension and expansion policy is set out in clause 5.6 of proposed Part A of our proposed access arrangement. Our proposed policy is unchanged from the policy currently in place, except for a minor clarifying amendment to clause 5.6.1(b)(2).

20.7. Changes to receipt and delivery points

The NGR requires that a full access arrangement must state the terms and conditions for changing receipt and delivery points, with any change made in accordance with specific principles.[141]

20.7.1. Proposed arrangements

Our policy for changing receipt and delivery points is set out in clause 5.8 of Part A of our proposed access arrangement. Our proposed policy is unchanged from the policy currently in place.

[139] Rule 48(1)(f) and Rule 105(1)(a).
[140] Rule 48(1)(g) and Rule 104.
[141] Rule 48(1)(h) and Rule 106(1).

Glossary

Abbreviation	Full name
AAI	Access Arrangement Information
ABS	Australian Bureau of Statistics
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGN	Australian Gas Networks
AGIG	Australian Gas Industry Group
Ai Group	Australian Industry Group
AMS	Asset Management System
API	Asset Performance Index
ATO	Australian Taxation Office
UAFG	Unaccounted for gas
ARS	Ancillary reference services
Augex	Augmentation capital expenditure
BAU	Business-as-usual
CALD	Culturally and Linguistically Diverse
CAM	Cost Allocation Methodology
Capex	Capital Expenditure
C&I	Commercial and Industrial
CCC	Customer Consultative Committee
CCP	Consumer Challenge Panel
CCTV	Closed Circuit Television
CESS	Capital Efficiency Sharing Scheme
CPF	Contingent Payment Factor
CIE	Centre for International Economics
CPI	Consumer Price Index
CPU	Corrosion Protections Unit

DAE	Deloitte Access Economics
DCC	Developer Consultative Committee
DELWP	Department of Environment, Land, Water and Planning
EBSS	Efficiency Benefit Sharing Scheme
ESC	Essential Services Commission
ESV	Energy Safe Victoria
EGWWS	Electricity, Gas, Water and Waste Services
EUAA	Energy Users Association of Australia
GDBs	Gas Distribution Businesses
GNIS	Gas Network Innovation Scheme
GJ	Gigajoule
GSL	Guaranteed Service Level
GSOO	Gas Statement of Opportunities
HIA	Housing Industry Association
HP	High pressure
IASB	International Accounting Standards Board
IT/ICT	Information Technology/Information and Communication Technology
KPI	Key Performance Indicators
LGA	Local Government Area
LIR	Leakage incident rate
LP	Low pressure
MP	Medium pressure
MHQ	Maximum hourly quantity
NGL	National Gas Law
MGN	Multinet Gas Networks
NGO	National Gas Objective
NGR	National Gas Rules
NPV	Net Present Value
OH&S	Occupational Health and Safety

Opex	Operating and Maintenance Expenditure
PE	Polyethylene
PSP	Priority Service Program
POE	Probability of Exceedance
PTRM	Post Tax Revenue Model
PV	Present Value
PVC	polyvinyl chloride
RAB	Regulatory Asset Base
RFM	Roll Forward Model
RIN	Regulatory Information Notice
RRG	Retailer Reference Group
SaaS	Software as a Service
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
STPIS	Service Target Performance Incentive Scheme
USAIDI	Unplanned Supply Average Interruption Duration Index
VGNSR	Victorian Gas Networks Stakeholder Roundtable
TAB	Tax Asset Base
WACC	Weighted Average Cost of Capital
WAPC	Weighted average price cap
WPI	Wage Price Index

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