Regulating gas pipelines under uncertainty

Information paper

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Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne VIC 3001

Tel: 1300 585 165

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Abbreviations

ACCC	Australian Competition and Consumer Commission
ACM	Authority for Consumers and Markets
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGN	Australian Gas Networks
ARENA	Australian Renewable Energy Agency
Capex	Capital expenditure
CCS	Carbon capture and storage
CESS	Capital expenditure sharing scheme
COVID-19	Coronavirus disease 2019
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DBNGP	Dampier to Bunbury Natural Gas Pipeline
DBP	DBNGP (WA) Transmission Pty Ltd
DELWP	Department of Environment, Land, Water and Planning
EBSS	Efficiency benefit sharing scheme
ECA	Energy Consumers Australia
EDBs	Electricity distribution businesses
ENA	Energy Networks Australia
ERA	Economic Regulation Authority Western Australia
GSOO	Gas Statement of Opportunities
GTS	Gasunie Transport Services
GW	Gigawatt
IASR	Inputs, Assumptions and Scenarios Report
IPART	Independent Pricing and Regulatory Tribunal
IRENA	International Renewable Energy Agency
JGN	Jemena Gas Networks
NEM	National Electricity Market
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
NSW	New South Wales
NT	Northern Territory

NZCC	New Zealand Commerce Commission
Ofgem	Office of Gas and Electricity Markets
Opex	Operating expenditure
PV	Photovoltaic
QLD	Queensland
RAB	Regulatory asset base
REZ	Renewable Energy Zone
SA	South Australia
TAS	Tasmania
VIC	Victoria
VRET	Victorian Renewable Energy Target
WA	Western Australia
WACC	Weighted average cost of capital
ZEV	Zero emissions vehicle

Executive summary

Australia's energy system is transitioning from a centralised, fossil fuel-based system to a decentralised, renewables-based system. This transition is part of the much broader, accelerating global movement towards carbon emissions reduction and is necessary to realise Australia's intention to reach net zero emissions by 2050. Australia's transmission and distribution networks, both electricity and gas, need to adapt to facilitate this transition but this will be challenging.

Gas pipelines are price regulated by the Australian Energy Regulator (AER) in instances where it is considered they have market power in the supply of gas services. Currently, we undertake this role for 3 transmission pipelines and 6 gas distribution networks in jurisdictions other than Western Australia. When determining a regulated access price for users of a gas pipeline, crucial determinants of the price level are the pipeline's efficient costs, along with the expected level demand for gas pipeline services over the access arrangement period.

The transformation in the energy system and the explicit policy goals of reaching net zero emissions by 2050 create considerable uncertainties in future gas demand expectations. We must have a view over the long term, not just one access arrangement period, to determine an equitable and efficient price path over time. We need to be cognisant of what may happen in the future and the determinants for the plausible energy scenarios that are foreseeable now. We must also be prepared to adjust our regulatory approaches given the new circumstances. The AER's focus is to ensure consumers are better off now and in the future. This will require us to exercise our regulatory judgement on a reset-by-reset basis, taking into account the demand for gas pipeline services on particular networks and balancing the risks and price impacts faced by consumers.

It is important that all stakeholders understand the longer-term issues facing the gas market, the regulatory landscape and how we may respond to the changes in the gas market. This is particularly the case given that the longer-term issues and the potential regulatory treatments are likely to underpin upcoming regulated businesses' access arrangement proposals and the prices consumers – both residential and business – will pay for retail gas services. Understanding these issues is the best way to ensure informed debate and feedback by stakeholders in our regulatory process. It will promote the beginning of a wider and ongoing discussion on how we navigate the uncertainties and the transformation of the industry to a low carbon future.

Uncertain future demand for natural gas and gas pipeline services

We have observed a range of factors that are likely to exert considerable downward pressure on natural gas demand in Australia's eastern states in the medium to long term, notwithstanding that gas customer numbers have been growing over the past decade. These factors include governments' decarbonisation policies, increasing competitiveness of electricity as a substitute for natural gas, improvements in energy efficiency, uncertainty in future gas prices and growing investment in renewable energy.

On the other hand, we also recognise factors that support the demand for gas in the short to medium term. Most consumers have not considered switching away from gas, particularly in those jurisdictions where reliance on gas is high. Not all gas applications can be substituted by electricity, especially for industrial users. Gas plays a critical role in supporting the reliability and resilience of our energy system as coal-fired power generation decreases and intermittent renewable energy generation increases. Further, the potential for renewable hydrogen and bio-methane to replace natural gas in various applications, including reticulated gas, are currently being explored. They may provide some upside to gas demand in the future, even though they are not commercially proven yet.

All these factors are expected to affect gas demand and utilisation of gas infrastructures in varying degrees across jurisdictions. The circumstances and the demand risks that each regulated gas pipeline business faces are often unique to their operating environment, the configuration of their pipeline assets and the composition of their customer base. Therefore, our regulatory approaches may differ across jurisdictions.

Challenge of determining appropriate regulatory measures under demand uncertainty

In the short run, gas demand may continue to grow, remain stable or begin declining. In the long run, gas pipelines and networks may need to wind-down or be repurposed to carry different gases. These two markedly different outcomes may have quite different implications for regulatory strategies today to achieve an optimal transition and efficient price paths.

The uncertainty associated with the potential of reticulating renewable hydrogen complicates our decisions on new investments, particularly those that may foreclose opportunities to repurpose existing gas networks, but which may save consumers from unnecessary costs in the scenario of a network wind-down. This is because, if there is a breakthrough in the production and transportation of renewable hydrogen, its commercial viability would likely depend on the scale of available customer demand, which is contingent on the growth and necessary investments in the gas networks in the lead up to the breakthrough.

In addition, while electrification is a proven technology in most residential gas applications, the costs of upgrading electricity networks to accommodate new energy demand from gas users could be so significant in some jurisdictions that it may not be possible to eliminate gas usage completely. Such uncertainties surrounding the future gas substitution pathways make it extremely challenging to manage growth in the gas market currently, while being mindful to the risk that there may be little remaining customers to pay for gas infrastructures in the future.

If the demand for gas services declines materially with no expected recovery, we anticipate:

- there would be fewer customers to share fixed gas network costs
- the cost burden of past investments may be disproportionately borne by future gas customers
- gas infrastructure assets may be economically stranded (stranded asset risk)
- the price volatility or uncertainty resulting from declining demand could drive further decline in demand.

These consequences can be mitigated or avoided if appropriate precautionary measures are taken. Consideration of intergenerational equity between current and future gas customers is important.

Gas pipeline businesses invest in long-lived assets. The concern that they may not recover the efficient costs of their investments because of the uncertainty in future demand for their services can negatively impact their current investment decisions. We seek to ensure regulated businesses can invest where necessary to provide safe and reliable gas services while protecting consumers from unnecessary cost burdens now and in the future. To avoid distorting investment incentives for consumers and encouraging further gas substitution, we aim to use careful regulation to minimise the risk of adverse price impacts resulting from possible falling demand. Price stability and affordability will be an important consideration in our decisions.

Preliminary view on preferred option to manage demand uncertainty

There are a number of available options to manage the pricing risks and stranded asset risks associated with a possible downward spiral in gas demand and to recover the efficient costs of gas pipeline investments more equitably among gas consumers over time. The options include adjusting depreciation, providing ex-ante compensation, sharing costs under capital redundancy provisions, removing capital base indexation, revaluing regulatory asset base, introducing exit fees and increasing fixed charges. Maintaining the status quo is a default option if the risks are not adequately substantiated. Not all options are accommodated within the current regulatory framework or consistent with the current charging practices of regulated businesses.

These options are also not mutually exclusive, although they may not all be warranted at the same time. Some options may be complementary, some may be more appropriate than others at different points in time and for different reasons, depending on the circumstances of individual regulated business. Stakeholders need to be aware of the pros and cons of each option when considering how they might engage on these issues in future regulatory access arrangement review processes.

Our preliminary view is that some form of accelerated depreciation would be appropriate if there is sufficient evidence to demonstrate and quantify the pricing risk and stranded asset risk arising from demand uncertainty. Accelerated depreciation allows us to respond to the forecast change in demand in a pragmatic manner and adjust the tariffs over time to facilitate an equitable and efficient allocation of costs between current and future gas customers. Importantly, adjusting depreciation offers us the greatest flexibility in responding to new information in the future if the natural gas substitution pathways or actual demand turn out to be different than expected.

Unlike other options under consideration, accelerating depreciation does not lock in a price change permanently. This avoids providing a material windfall gain or loss to either the regulated businesses or consumers if actual gas demand differs markedly from our assumption made under uncertainty. Depreciation can be adjusted in later access arrangement periods when the future of gas networks utilisation becomes clearer. Also, the price impact of accelerated depreciation can be more equitably spread among all gas customers of the network and not confined to a specific sub-group.

In exercising our regulatory role in access arrangement reviews, we will carefully consider the surrounding circumstances of a regulated business to determine the materiality of the demand risk it faces and assess the efficiency and prudency of the measures it proposes to mitigate pricing risks. We will make our decisions on a case-by-case basis and review our approaches as required when new information becomes available. Our decisions will in large part be guided by jurisdictional climate change or decarbonisation policies that affect network service providers and energy users, technological developments in renewable energy, and stakeholders' views. We aim to retain flexibility and not foreclose opportunities in our regulatory decisions where possible.

Other regulatory considerations in an environment of uncertainty

Long-term demand risk can influence our regulatory decisions on network investments, allocation of risk and incentives. The potential adverse price impacts arising from a fall in demand may warrant a more stringent expenditure assessment approach to account for that risk specifically. Demand forecasts that underpin the need for new investments should be carefully scrutinised. Stranded asset risk may act sufficiently as a deterrent for excess network investments and may reduce the need for strong financial incentives to reward expenditure underspends. The implicit allocation of demand risk and incentives operating under price-cap regulation may need to change. Significant forecasting error in gas demand may warrant variations to access arrangements in mid-period.

Furthermore, our regulatory framework has limitations in responding to possible changes in the energy market. First, there is an inherent tension between the national gas objective that implicitly encourages greater gas consumption and the wider climate change policy actions to reduce fossil fuel use. Second, if a large proportion of gas consumers switch from gas to electricity, this may have significant cost implications for electricity networks. It may be relevant in some circumstances to consider the interests of electricity consumers when making decisions under the national gas regulatory framework. Third, the current regulatory regime may not be fit-for-purpose in circumstances where a partial or complete wind-down of gas networks is required or where gas network businesses can no longer exercise substantial market power. Lastly, the current regulatory framework may present challenges for the cost recovery of sustainable gas-related expenditures. Without strong consumer support or preference for sustainable gas, incurring sustainable gas-related expenditures may not be considered as efficient for the provision of gas services when natural gas is still available as a cheaper alternative.

Next steps

We invite stakeholders who are interested in providing their views on the issues highlighted to make submissions in the upcoming Victorian gas access arrangement reviews for APA VTS (due to commence in December 2021), Multinet Gas, AGN and AusNet Services (all due to commence in July 2022). Stakeholders can participate in any public forum that we hold for an access arrangement review and have two opportunities to make written submissions during an access arrangement review:

- in response to the AER's issues paper and the regulated business's access arrangement proposal

- in response to the AER’s draft decision and the regulated business’s revised access arrangement proposal.

1 Introduction

Gas has been an important energy source and input for industrial and domestic use. The electricity, manufacturing and mining industries have used gas for creating their respective outputs. In the domestic setting, gas has been used for space and water heating and cooking.

An important role of the AER is to set access prices (also known as reference tariffs) for 'full regulation' pipelines and evaluate the efficiency of expenditures incurred in the provision of gas pipeline services.[1] We rely on forecast demand to set efficient access prices and to determine the prudency of the investments incurred in the provision of gas pipeline services.

The legal framework that underlies the regulation of gas networks was conceptualised with the assumption that future demand for gas would be growing or steady. However, this assumed paradigm is starting to be challenged because of the energy transformation in Australia, including the retirement of fossil fuel generators for electricity and growing investment in renewable energy. Coupled with decarbonisation policies, the structural transformations in the energy sector give rise to significant uncertainty in natural gas demand.

There are many unknowns associated with the decarbonisation of the natural gas sector and the future energy mix. There are differing outlooks across Australian states and territories depending on the degree of consumers' reliance on gas and the climate change-related commitment made by the respective governments. We recognise the considerable uncertainty in future gas demand projections, with many factors implying a reduction in demand in the long term. This uncertainty is further heightened by the longer-term possibility of increased demand through a switch from natural gas to hydrogen. We are concerned about how these uncertainties affect the way we determine efficient access prices over time and the intergenerational equity between current and future gas customers. There is the potential for an increase in gas access prices if gas demand drops sharply in the future, which will ultimately be borne by households and industry.

With so much uncertainty surrounding the future demand for gas pipeline services, we seek to ensure regulated businesses can invest where necessary to provide safe and reliable gas services while protecting consumers from unnecessary cost burdens now and in the future. To avoid distorting investment incentives for consumers and encouraging further gas substitution, price stability and affordability will be a paramount consideration in our decisions.[2]

This information paper aims to assist stakeholders to understand how the energy transition currently underway affects regulated gas networks and its implications for the economic regulation of gas pipelines and networks and, in turn, the implications for consumers. We outline a range of possible options to manage pricing risk and stranded asset risk arising from a potential material

[1] For a pipeline that is subject to 'full regulation', the pipeline operator must prepare an access arrangement for the regulator to approve. The access arrangement includes price and non-price terms and conditions for third parties to gain access to the pipeline. It provides a starting point for parties to negotiate access on commercial terms. 'Full regulation' pipelines include 3 transmission pipelines – the Roma to Brisbane Pipeline (Queensland), the Victorian Transmission System, and the Amadeus Gas Pipeline (Northern Territory) – and 6 distribution networks in NSW, Victoria, South Australia and the ACT.

[2] Under the national gas regulatory framework, increasing network utilisation and connection numbers is generally considered to be in the long-term interest of gas consumers. Therefore, it is important to protect consumers' sunk investments and their incentives to invest.

decline in gas demand in the long term. Not all the options considered are accommodated within the current regulatory framework.

Some options may require a change to the regulatory framework or the way regulated businesses price their services. We explore the merits and costs of each option and note that a combination of the options may be appropriate depending on the regulated business's circumstances. We also analyse how the uncertainty in future demand may affect our assessment of network expenditures going forward and the incentives provided under the current regulatory framework.

The information provided and the issues raised in this paper should facilitate informed engagement between gas consumers, regulated businesses, governments and the AER. In particular, we see the information paper as being a crucial input into the upcoming Victorian gas transmission and distribution access arrangement reviews. Therefore, we invite stakeholders to participate in upcoming gas access arrangement reviews, and the processes leading up to those reviews, and provide feedback on how we can best respond to the changes in the energy sector in a way that is consistent with the National Gas Objective (NGO).[3] This can be done through written submissions, engagement in public forums or through discussions with the AER.

Stakeholders will have two opportunities to make written submissions during an access arrangement review:

- in response to the AER's issues paper and the regulated business's access arrangement proposal
- in response to the AER's draft decision and the regulated business's revised access arrangement proposal.

To highlight the uncertainty around the future of gas, the opportunities and challenges faced by networks, and the potential regulatory solutions, the paper is structured as follows:

- Section 2 outlines the drivers that contribute to the uncertainty of future gas demand, the plausible future energy scenarios forecast by different parties and the implications of the different natural gas substitution pathways
- Section 3 explains the impact of declining gas demand on gas customers and regulated gas network businesses
- Section 4 discusses a range of potential options to address demand uncertainty and possible stranded asset risk
- Section 5 discusses what other changes the AER may make to its regulatory approaches when undertaking access arrangement reviews, in light of the uncertainty in future gas demand
- Section 6 explores the limitations of national gas regulatory framework in adapting to a low-carbon energy transition, including the introduction of renewable gas and the potential need to wind-down a gas network.

[3] The National Gas Objective 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.

2 Increasing uncertainty in future natural gas demand

A range of factors are likely to exert downward pressure on natural gas demand in Australia's eastern states in the medium to long term, notwithstanding that gas customer numbers have been growing over the past decade. Climate change policies are a key determinant of the future outlooks of gas demand. They incentivise many of the technological and competition changes in the energy market that can affect consumers' energy consumption.

The overarching mandate to reduce carbon emissions by 2050 requires that natural gas, as a fossil fuel, must be replaced by low-emissions technologies. The two biggest contenders of substituting natural gas are either electricity or renewable gases (specifically renewable hydrogen gas). However, the transition from gas to electricity or hydrogen is unlikely to occur immediately or within a short time frame.

In the short run, gas demand may continue to grow, remain stable or begin declining. In the long run, subject to the possibility of replacing natural gas with different gases, gas pipelines or networks may either need to wind-down or be repurposed. We explain the factors that contribute to the uncertainty in natural gas demand in this section, which covers:

- those factors that are contributing to the uncertainty of natural gas demand (section 2.1)
- forecasts for long-term gas demand (section 2.2)
- potential for sustainable gas solutions such as hydrogen and bio-methane (section 2.3)
- forecast of the future energy mix and the effect on the gas sector and networks (section 2.4)
- the implications for the sector of different ways of substituting away from natural gas (section 2.5).

2.1 Drivers that contribute to the uncertainty in natural gas demand

2.1.1 Decarbonisation policies

Because of climate change concerns, governments are now progressively making policies to reduce carbon emissions, such as providing incentives for residential customers to install solar photovoltaics and batteries or to increase the energy efficiency of their appliances and homes.

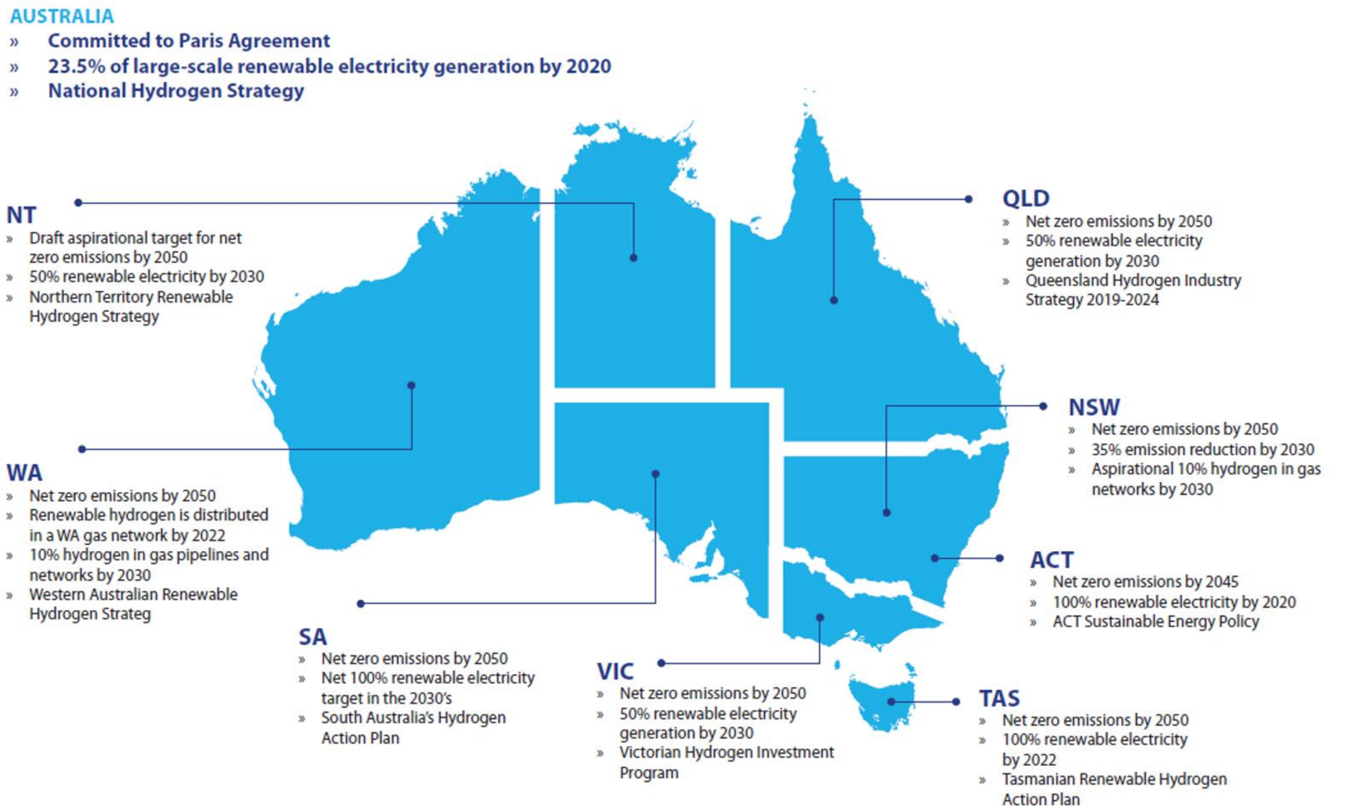
As a party to the Paris Agreement, Australia has committed to reduce our greenhouse gas emissions by 26–28% below 2005 levels by 2030.[4] On 26 October 2021, the Australian Government announced that it would commit to a target of net zero carbon emissions by 2050 and it would see more than $20 billion invested in 'low-emissions technologies' by 2030.[5] All Australian states and territories have adopted a net zero emissions target by 2050 (either aspirational or legislated) and some have mandated renewable electricity targets as well (see Figure 1). While the necessary policies and government actions required to achieve such targets have yet to be

[4] The Paris Agreement aims to strengthen the global response to the threat of climate change by holding the increase in the global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit temperature increase to 1.5°C. For information, please see https://unfccc.int/process-and-meetings/the-paris-agreement/the-paris-agreement

[5] See Prime Minister of Australia and Minister for Industry, Energy and Emissions Reduction, *Australia's plan to reach our net zero target by 2050*, Media Release, 26 October 2021. Accessed via: https://www.pm.gov.au/media/australias-plan-reach-our-net-zero-target-2050

fully formulated, it is reasonable to assume that natural gas consumption must decline substantially to achieve any net zero emissions targets by 2050.[6]

Figure 1 Emissions reduction commitment by jurisdiction



Source: Energy Networks Australia analysis (2020)[7], current as at September 2020.

Note: NSW Government announced a new 50% emissions reduction target by 2030 on 29 September 2021. Federal Government announced a net zero emissions target by 2050 on 26 October 2021.

Most state and territory governments have also committed to developing renewable hydrogen industries. This paves the way for the possibility of replacing natural gas with hydrogen in specific applications, including reticulated gas, but it still faces a number of technical and cost challenges.

Governments are also actively exploring the commercial viability of biogas/bio-methane and carbon capture and storage[8] as potential pathways to abate carbon emissions from natural gas use. Appendix A provides a summary table of the energy transition initiatives implemented by each jurisdiction.

[6] See for example, the Victorian State Government is currently consulting on its Gas Substitution Roadmap to provide a strategic framework for decarbonising natural gas in Victoria. Accessed via: https://engage.vic.gov.au/help-us-build-victorias-gas-substitution-roadmap

[7] Energy Networks Australia, *Gas Vision 2050 Delivering a Clean Energy Future*, September 2020, p.25.

[8] Carbon capture and storage (CCS) is a process of capturing and permanently storing carbon emissions.

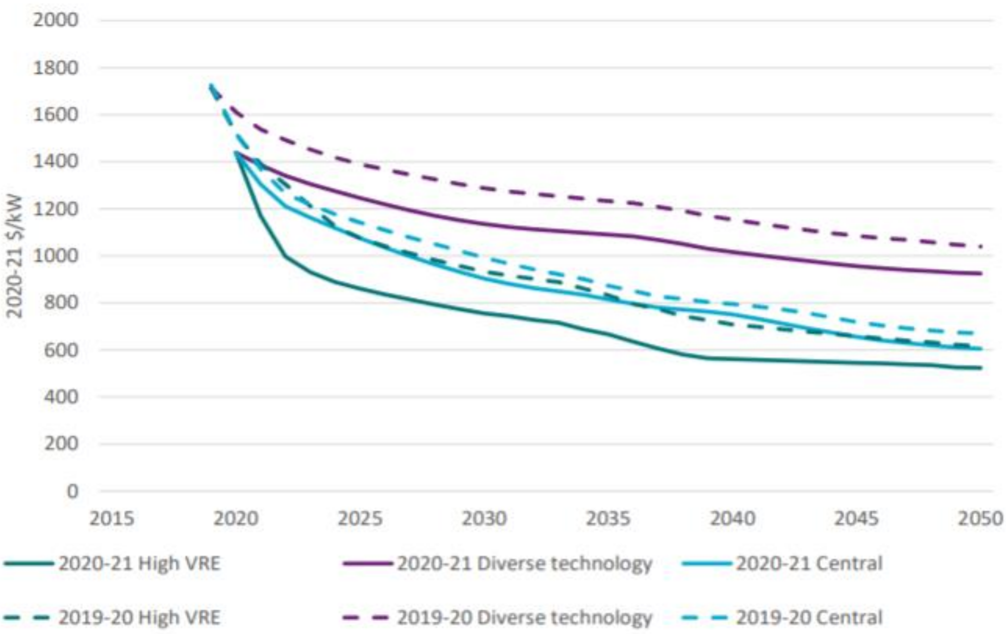
2.1.2 Increasing competitiveness of renewable electricity

Governments' climate change-related policies have resulted in fast-growing distributed energy resources and renewable energy markets, making renewable electricity more competitive against natural gas at both the retail and wholesale levels.[9]

Solar photovoltaic (PV) generation, a distributed energy resource, has been growing at the residential level in the past decade. Clean Energy Regulator data shows that more than 2.68 million rooftop solar power systems have been installed in Australia in total, as of 31 December 2020 – that means one in four homes has solar panels on their roof.[10]

According to the GenCost 2020–21 report prepared by the Australian Energy Market Operator (AEMO) and the Commonwealth Scientific and Industrial Research Organisation (CSIRO), the projected capital costs for rooftop solar PV continue to fall in the coming decades (see Figure 2).[11] Falling costs and increasing accessibility continues to fuel the uptake of solar PV in the residential market.

Figure 2 Projected capital costs for rooftop solar PV by scenario



Source: GenCost 2020-21 Final Report, CSIRO

Note: High VRE refers to a scenario where technical, social and political support for variable renewable electricity generation is high, in a world that is driving towards net zero emissions by 2050. Diverse Technology refers to a scenario where most developed countries are striving for net zero emissions by 2050 but others are lagging such that global net zero emissions is reached by 2070. Furthermore, there is lack of social, technical and political support for variable renewable electricity generation and subsequently a greater role for other technologies.

According to the GenCost 2020–21 report, batteries have been able to sustain high-cost reduction rates over time.[12] The current capital cost of 2-hour duration large-scale batteries has been

[9] One key government policy is the Renewable Energy Target, which incentivises the development of new renewable energy power stations. Roof-top solar panels are incentivised by state-based feed-in tariffs and state government solar panel rebates.

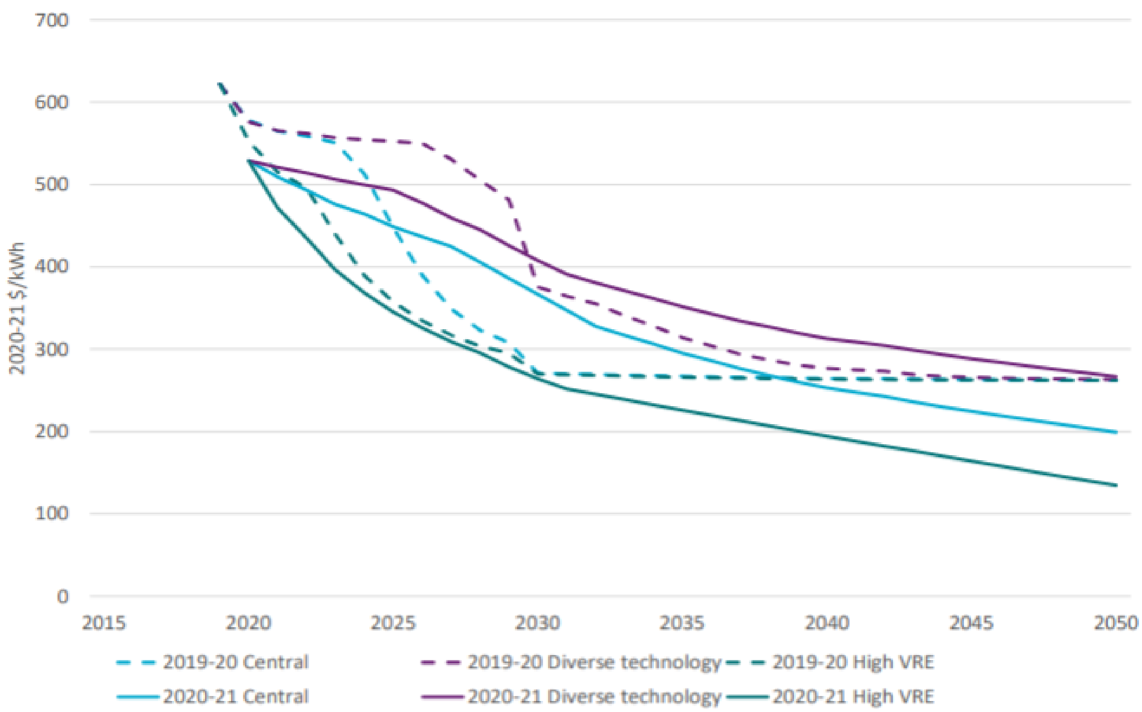
[10] See https://www.csiro.au/en/news/news-releases/2021/australia-installs-record-breaking-number-of-rooftop-solar-panels

[11] Graham, P., Hayward, J., Foster J. and Havas, L., *GenCost 2020-21: Final report*, June 2021, p. 44.

[12] Graham, P., Hayward, J., Foster J. and Havas, L., *GenCost 2020-21: Final report*, June 2021, p. 46.

revised downwards from $622/kWh to around $529/kWh.[13] Figure 3 shows the projected future change in battery pack costs. Battery storage is not cost-effective in most residential applications yet, but it represents a growing market.[14] Rooftop solar PV, coupled with batteries when they become economical, will likely provide consumers with greater cost-efficiencies in using electric appliances.

Figure 3 Projected total capital costs for 2-hour duration batteries by scenario



Source: GenCost 2020-21 Final Report, CSIRO

Note: High VRE refers to a scenario where technical, social and political support for variable renewable electricity generation is high, in a world that is driving towards net zero emissions by 2050. Diverse Technology refers to a scenario where most developed countries are striving for net zero emissions by 2050 but others are lagging such that global net zero emissions is reached by 2070. Furthermore, there is lack of social, technical and political support for variable renewable electricity generation and subsequently a greater role for other technologies.

The cost of electricity production from solar and wind power has fallen to very low levels, undercutting the price of electricity produced by fossil fuels including coal and natural gas.[15] Renewable power generation cost declines have been driven by steadily improving technologies, economies of scale, competitive supply chains and improving developer experience. Costs of electricity from utility-scale solar PV fell 85% between 2010 and 2020.[16]

The pace of change in the energy sector is significant, affecting both the electricity and gas markets. Renewable electricity threatens the profitability of gas-fired power generation under certain conditions, while distributed energy resources can make all-electric homes more cost-competitive than dual-fuel home. The demand for natural gas, both at the wholesale and retail

[13] Graham, P., Hayward, J., Foster J. and Havas, L., *GenCost 2020-21: Final report*, June 2021, p. 47.

[14] Small scale batteries for home use with 2-hour duration cost around $1250/kWh, according to SunWiz's Australian battery market report 2021.

[15] See for example, AGL's decision to shut down gas-fired power unit as renewable energy soars: https://www.theage.com.au/business/companies/agl-to-shut-down-gas-fired-power-unit-as-renewable-energy-soars-20210707-p587jb.html

[16] International Renewable Energy Agency (IRENA), *Renewable Power Generation Costs in 2020*, June 2021.

levels, is subject to downward pressure as a result of decreasing costs in renewable power generation and distributed energy resources.[17]

2.1.3 Energy efficiency improvements

Improving energy efficiency is encouraged as a key measure to reduce natural gas demand and carbon emissions.[18] Technological improvements in the efficiencies of electrical appliances may make them cheaper and more environmentally friendly to use, compared with gas appliances. For example, the most efficient reverse cycle air conditioning (or heat pump) units may be cheaper to run and generate lower greenhouse gas emissions than gas heaters.[19] Improvements in the efficiencies of gas appliances may also result in less gas consumption.

Governments have implemented a range of initiatives for both residential and commercial users of natural gas to improve their energy efficiency. For example, in the 2020–21 State Budget, the Victorian Government committed $447 million to improve the energy efficiency of homes for low-income and vulnerable Victorians, including financial assistance to install reverse cycle air conditioners in low-income households, to install upgrades to improve thermal performance (with insulation and drought-proofing) and replace inefficient appliances in 35,000 public and community housing properties.[20]

For larger industrial users, the Victorian Government has established a Business Recovery Energy Efficiency Fund to help them introduce energy efficiency and demand management technologies. It has also expanded its flagship Victorian Energy Upgrades program to include insulation of hot water pipework, replacement of commercial and industrial gas boilers, smart thermostats and energy management systems for businesses.[21]

With government subsidies to increase the uptake of energy efficient appliances and to improve building design, the relative cost of electricity compared with gas is going to decrease and there is likely to be an overall reduction in energy consumption. This is likely to translate to a reduction in the demand for natural gas going forward.

2.1.4 Uncertainty in future gas prices

Uncertainty in future gas prices, or an expectation of rising gas prices, can influence consumers' investments in gas appliances and gas consumption.

The development of Queensland's liquefied natural gas export industry placed significant pressure on the eastern gas market. The pressure, combined with other factors such as state-based moratoriums on gas development, tightened the supply–demand balance. This tightening led to

[17] Demand for gas at the wholesale level may nevertheless be supported by industrial customers' use of natural gas as a chemical feedstock or for process heating, where electricity cannot be used as a substitute.

[18] See for example, Victoria Government, *Victoria's Gas Substitution Roadmap Consultation Paper*, June 2021, p.28.

[19] Australian Government, *Your Home – Australia's guide to environmentally sustainable homes,* updated in 2013, accessed via https://www.yourhome.gov.au/energy/heating-and-cooling.

[20] Victoria Government, *Victoria's Gas Substitution Roadmap Consultation Paper*, June 2021, p.8.

[21] Victoria Government, *Victoria's Gas Substitution Roadmap Consultation Paper*, June 2021, p.28.

increases in wholesale gas prices from 2017. Natural gas exports also linked our domestic gas prices to international commodity prices.[22]

The Australian Government has taken steps to address the forecast risk of supply shortfalls that may lead to higher domestic gas prices. The Government's interim National Gas Infrastructure Plan has identified the highest priority infrastructure investments required to alleviate the forecast risk of supply shortfalls in the east coast gas market in the short-term to 2027.[23] The Government also committed $74.3 million to help accelerate priority gas supply projects in the 2021-22 budget.[24] The Government is currently designing its Future Gas Infrastructure Investment Framework to support medium to long term gas infrastructure projects.[25]

The increase in gas prices in eastern Australia since 2015 is sometimes attributed to an increase in domestic gas production costs.[26] Eastern Australia still has significant supplies of gas, but they are typically unconventional coal seam gas that is more expensive to produce than conventional gas. The Surat-Bowen gas basin in Queensland, which produces coal seam gas, accounted for about 86% of the eastern Australia's remaining gas reserves in 2021 and about 76% of eastern Australian gas production in 2020.[27] Outside Queensland, the three Victorian gas basins that produce conventional gas meet most of the remaining demand in the eastern states, but their total reserves are declining.[28] Further, large new resources, such as the Northern Territory's Beetaloo Basin shale gas fields, are far from major markets.[29] The higher marginal cost of unconventional gas production means that domestic gas prices are expected to remain higher than pre-2015 levels over coming decades.[30]

Industrial consumers are sensitive to energy costs, and closure of industrial facilities remains an ever-present risk if energy costs are high. Higher gas prices have weakened gas demand by industrial customers since 2014. Despite this trend, industrial demand remained relatively steady across 2020, supported by easing prices. The COVID-19 pandemic does not appear to have had a significant effect on demand from industrial customers so far. However, the impact of COVID-19 on other areas of these businesses may lead to heightened sensitivity to future gas prices and affect consumption.[31]

2.1.5 Consumer sentiment towards gas

As climate change awareness continues to grow and electricity becomes more competitive compared with natural gas, some consumers may consider switching away from gas (or fossil

[22] AER, *State of the energy market 2021*, July 2021, p.198.

[23] The Australian Government committed to developing a National Gas Infrastructure Plan as part of a $10.9 million funding allocation in the 2020-21 budget for the Gas Fired Recovery package. The Government released the interim National Gas Infrastructure Plan on 7 May 2021, available at: https://www.energy.gov.au/government-priorities/energy-markets/gas-markets. The full National Gas Infrastructure Plan is due for release later this year and is intended to serve as a blueprint for a strategic approach to investment in critical gas infrastructure out to 2041.

[24] The Commonwealth of Australia, *Budget 2021-22, Budget Strategy and Outlook Budget Paper No. 1 2021-22*, May 2021, p.26.

[25] See Department of Industry, Science, Energy and Resources, *Gas-Fired Recovery: Infrastructure and Investment Consultation Note*, July 2021. Available at https://consult.industry.gov.au/gas-fired-recovery

[26] De Atholia T, Walker A, *Understanding the East Coast Gas Market*, Reserve Bank of Australia Bulletin, March 2021.

[27] AER, *State of the energy market 2021*, July 2021, p.185.

[28] AER, *State of the energy market 2021*, July 2021, p.185.

[29] Grattan Institute, *Flame out – the future of natural gas*, November 2020, p.10.

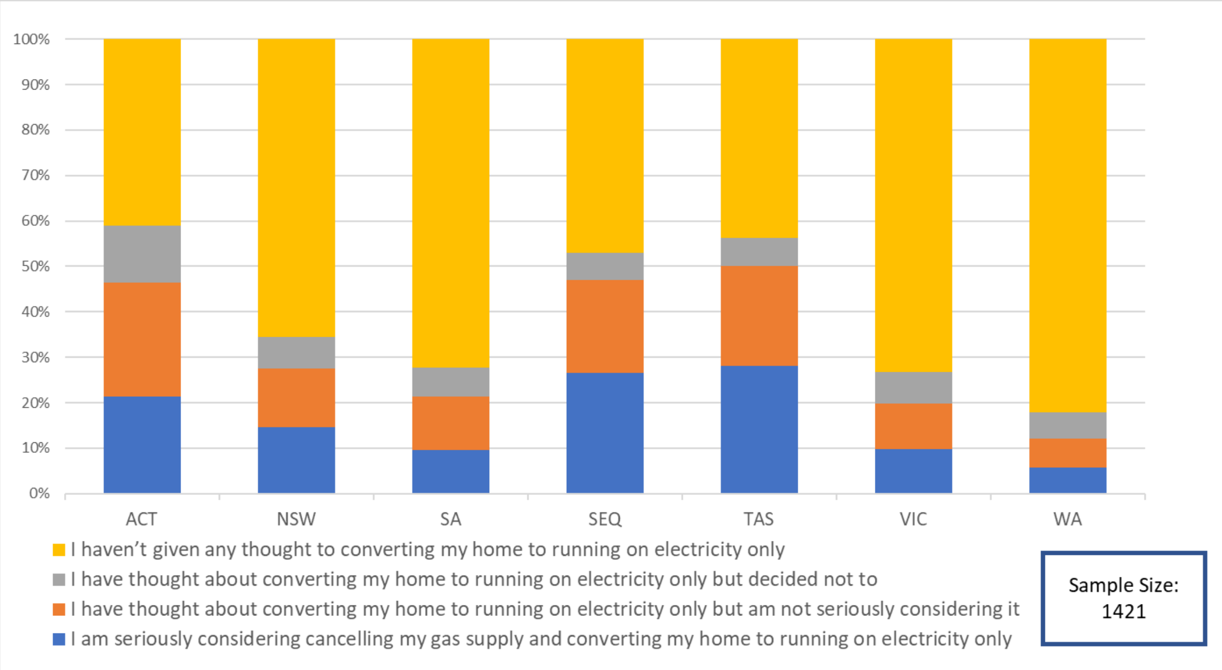
[30] De Atholia T, Walker A, *Understanding the East Coast Gas Market*, Reserve Bank of Australia Bulletin, March 2021.

[31] AER, *State of the energy market 2021*, July 2021, p.201.

fuels) independent of governments' climate change policies. Currently, there is limited knowledge on consumer preferences and attitudes towards natural gas.[32] This makes it difficult to forecast long-term gas demand trends.

The Energy Consumer Sentiment Survey 2021 conducted by Energy Consumers Australia (ECA) provides some insight into consumer sentiment in switching away from gas to using electricity only.[33] As shown in Figure 4, the proportion of consumer survey participants that are seriously considering or have considered switching from gas to electricity vary in different jurisdictions, but are more prominent in the ACT, Tasmania and south-east Queensland compared with other states. These consumer sentiments may be indicative of the consumers' relative ability or preference to exit the gas networks in the short to medium term.

Figure 4 Surveyed residential consumers' responses about their sentiment towards switching from gas to electricity only, sorted by state



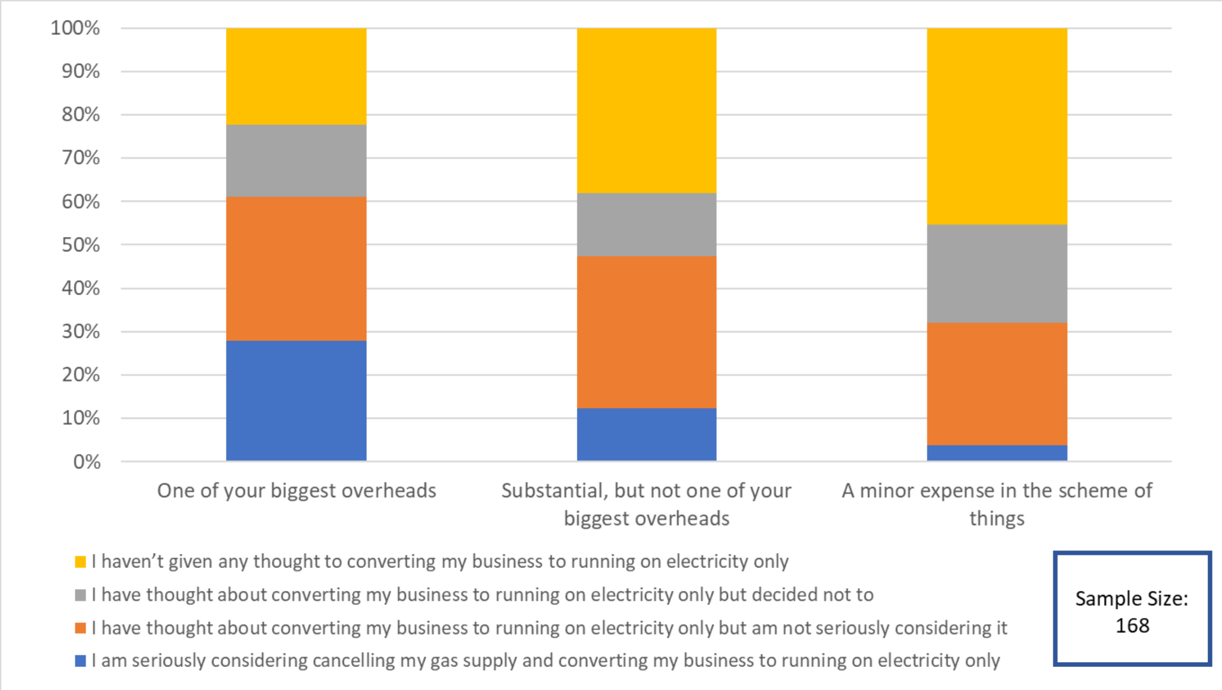
Source: AER's analysis of ECA's survey responses.

It is also not surprising to see that, for commercial or industrial gas users whose gas expenses are a major part of their operation costs, they are more likely to have considered converting their businesses to running on electricity only (see Figure 5). However, for industrial and commercial users who use gas as a feedstock, there may not be any gas substitutes available so it may not be possible for them to switch from gas to electricity.

32 Infrastructure Victoria, *Towards 2050: Gas infrastructure in a zero emissions economy*, July 2021, p.33.

33 ECA, *Energy Consumer Sentiment Survey 2021*, June 2021, accessed via: https://ecss.energyconsumersaustralia.com.au/sentiment-survey-june-2021/

Figure 5 Surveyed business consumers' response about their sentiment towards switching from gas to electricity only, sorted by the relative proportion of business costs that are gas expenditures



Source: AER's analysis of ECA's survey responses.

2.1.6 Corporate and investor activism

As the impact of climate change is increasingly felt, there is growing social pressure on corporations to invest and operate in a way that is consistent with environmental sustainability as part of their corporate social responsibilities. Climate-related shareholder activism is also on the rise.[34] This could mean reducing demand for natural gas from commercial and industrial users in the future.

For example, AustralianSuper, a major investor in many companies, has made a commitment to achieve net zero carbon emissions by 2050 in its investment portfolio.[35] Within the energy sector, AustralianSuper currently has plans to invest more in renewables and reduce carbon emissions in its portfolio as new technologies are developed and companies transition their businesses to a lower carbon economy.

Commercial and industrial users are beginning to recognise the risk of investing in fossil fuel technologies and the benefits associated with climate change actions. As such, some corporations have begun their transition to renewable energy irrespective of government climate change

[34] See for example, Michael Roddan, Financial Review, *Industry super drives increase in ESG support*, 7 September 2021. Accessed via https://www.afr.com/companies/financial-services/industry-super-drives-increase-in-esg-support-20210906-p58p50

[35] See https://www.australiansuper.com/investments/how-we-invest/climate-change

policies.[36] For instance, major supermarket chains such as Woolworths, ALDI and Coles have all committed to reduce their carbon emissions and use renewable electricity.[37]

2.1.7 Demand for gas to generate electricity

Gas plays a critical function in electricity generation because gas-powered generation can service peak demand and quickly ramp production up or down to balance fluctuations in electricity supply from other sources. This stabilising role is important, particularly during periods of low variable renewable energy generation. As a result, gas-fired generation often impacts the marginal price for wholesale electricity. Combined-cycle gas-powered generation can also substitute for base-load coal-fired power generation.

In the 2021 Gas Statement of Opportunities (GSOO), AEMO forecast that the volume of gas consumed for generating electricity will fall because of increased renewable energy sources, but the value of that generation is expected to increase as gas-powered generation demand may become more ‘peaky’.[38]

AEMO has outlined the need to continue using gas-powered synchronous generating units as a form of energy security in all eastern states of Australia. In the Inputs, Assumptions and Scenarios Report (IASR), AEMO assumes a current need for a minimum of 28 large synchronous generating units (coal-fired or gas-fired generators) to ensure electricity system security and reliability in its planning studies.[39] However, AEMO has removed this assumption from 2025 onwards. This does not reflect that AEMO considers synchronous generating unit commitment will not be required after 2025, but rather that unit commitment is not assumed to be the only solution to deliver system security services after 2025.[40] The expectation that synchronous generating units may not be required from 2025 suggests that there may be less reliance on natural gas as a source of electricity generation stability and frequency control in the future.

2.2 Long-term gas demand forecast

In the 2021 GSOO, AEMO notes that ‘annual gas consumption in the next 20 years is uncertain, with downside risks outweighing the likelihood of gas consumption growth’.[41]

AEMO forecasts gas demand and production to project the supply–demand balance and potential gaps under a range of plausible scenarios for eastern and south-eastern Australian gas systems to 2040.[42]

36 See for example, Richard Henderson, Financial Review*, Net zero pledges soar after earnings season boost*, 6 September 2021. Accessed via https://www.afr.com/markets/equity-markets/net-zero-pledges-soar-after-earnings-season-boost-20210906-p58pag

37 See, https://www.woolworthsgroup.com.au/page/media/Latest_News/woolworths-group%E2%80%99s-2030-emissions-reduction-targets-endorsed-by-un-backed-science-based-targets-initiative; https://corporate.aldi.com.au/en/corporate-responsibility/environment/renewable-electricity/ and https://www.coles.com.au/about-coles/sustainability/environment/together-to-zero-emissions.

38 AEMO, *2021 Gas Statement of Opportunities*, March 2021, pp.4, 8.

39 AEMO, *Inputs Assumptions and Scenarios Report*, July 2021, pp. 139-141.

40 AEMO, *Inputs Assumptions and Scenarios Report*, July 2021, pp. 139-141.

41 AEMO, 2021 *Gas Statement of Opportunitie*s, March 2021, p.20.

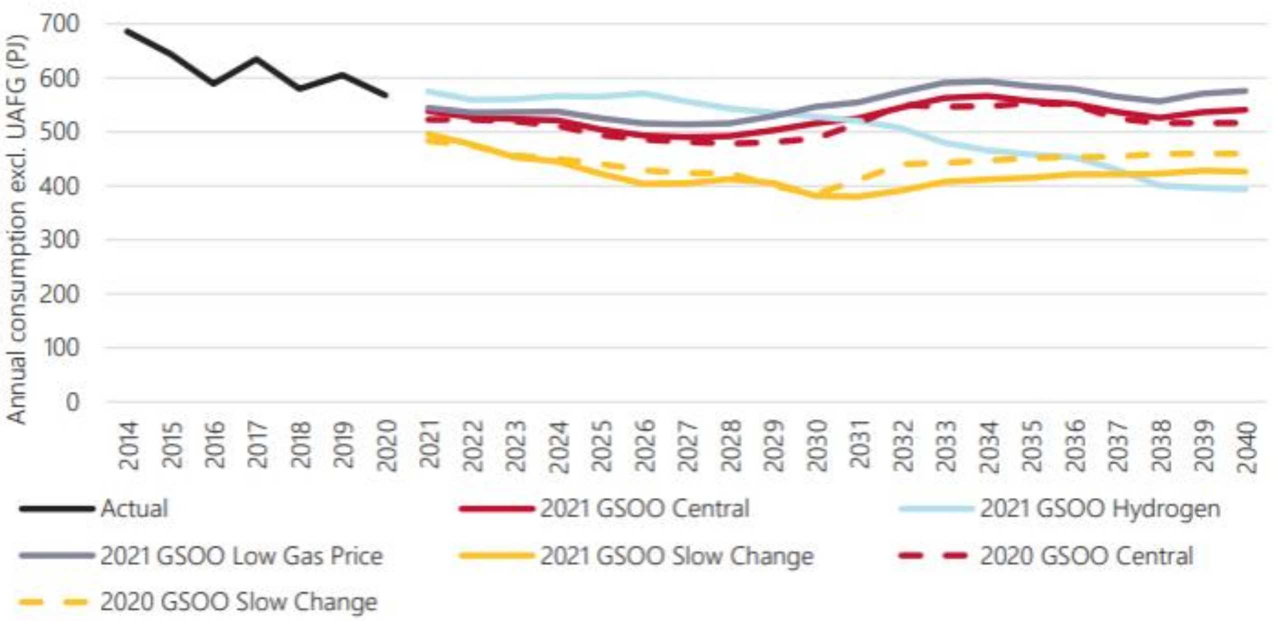
42 AEMO, *2021 Gas Statement of Opportunities*, March 2021, p.3.

For the 2021 GSOO, modelling was conducted based on four futures for gas in eastern and south-eastern Australia:

- **Central** scenario – uses AEMO's best (central) view of future uncertainties
- **Slow Change** scenario – explores reduced gas demand due to slowing economic activity and higher gas prices
- **Hydrogen** scenario – explores potential gas infrastructure impacts of the development of electrolyser-produced hydrogen under stronger economic conditions, which could provide a potential substitute for gas use in certain applications
- **Low gas price** scenario – explores potential impacts of lower gas prices on consumption by residential, commercial and large industrial consumers, and gas-powered generation.

Figure 6 shows the range of consumption forecasts AEMO made in the 2021 GSOO and compares the Central and Slow Change scenario projections to equivalent forecasts in the 2020 GSOO.[43]

Figure 6 AEMO's domestic gas consumption actual and forecast, 2014 to 2040, excluding LNG (PJ)



Source: AEMO 2021 GSOO

AEMO's gas demand forecasts in the 2021 GSOO did not consider the impact of state or territory governments' climate change policies or net zero emissions targets. AEMO's residential and commercial consumption forecasts use forward estimates of consumption on a per connection basis. AEMO notes that its forecast number and type of new connections drive the growth

[43] AEMO, 2021 *Gas Statement of Opportunities*, March 2021, p.9.

trajectory, subject to other behavioural influences such as consumers' responses to pricing stimuli, appliance fuel-switching, and broader energy efficiency impacts.[44]

AEMO's gas consumption forecasts are likely to change in the 2022 GSOO because AEMO has indicated in its *Inputs, Assumptions and Scenarios Report 2021* that the five scenarios it will use for 2022 GSOO will reflect decreasing carbon intensity of the energy sector at different rates. This is further discussed at section 2.4.1.

2.3 Potential sustainable gas applications

The development of hydrogen or bio-methane (sustainable gases) as substitutes for natural gas is at an early stage and is highly uncertain. There are economic and technical barriers for large-scale production for both hydrogen and bio-methane. However, if successful, these sustainable gases may allow existing gas infrastructure to be modified and used under a net zero emissions environment.

2.3.1 Hydrogen

Hydrogen can replace many current gas applications. It can be used as both an energy supply and an industrial feedstock for chemical production. Combustion of hydrogen produces water with no carbon gas.[45]

To reduce carbon emissions, hydrogen must be produced from low-emissions sources. The most prospective ways of doing this are by using renewable electricity to split water into hydrogen and oxygen into separate gas streams through electrolysis ('green hydrogen' or 'renewable hydrogen') or by producing hydrogen from fossil fuels and capturing and storing the resulting carbon dioxide.[46]

Although the production of hydrogen through electrolysis is a known technology, it is currently inefficient and therefore very costly to produce at a large scale.[47] Also, more work is needed to understand the potential to produce green hydrogen from stormwater, wastewater or seawater, so that our limited fresh water can be used for drinking, the environment and growing food.[48]

Because hydrogen can be used to generate electricity (through fuel cells or being burned to drive turbines), it can be used as a renewable energy source that can be stored for long periods of time and transported at scale. This could be an important application of hydrogen in contributing to the reliability of electricity supply if proven more economically viable than other storage measures, given the weather-dependent nature of renewable energy sources such as solar and wind power. Hydrogen also has potential in many other applications, including hydrogen-fuel cell vehicles, and may play a part in decarbonising the transportation sector. While hydrogen costs are currently

44 AEMO, *2021 Gas Statement of Opportunities*, March 2021, p.27.

45 However, burning hydrogen, as opposed to using hydrogen in fuel cells, may produce nitrous oxide (a greenhouse gas) in certain environments. See for example, Lew Milford, Seth Mullendore, Abbe Ramanan, Clean Energy Group, *Hydrogen Hype in the Air*, December 2020. Accessed via: https://www.cleanegroup.org/hydrogen-hype-in-the-air/

46 Victorian Government, *Help build Victoria's Gas Substitution Roadmap*, June 2021, p. 31.

47 Infrastructure Victoria, *Towards 2050: Gas infrastructure in a zero emissions economy*, July 2021, p.21.

48 Infrastructure Victoria, *Towards 2050: Gas infrastructure in a zero emissions economy*, July 2021, p.21.

high, they are likely to become more cost-competitive if electrolyser production economies of scale ramp up and renewable electricity prices decline.[49]

Hydrogen's potential as a substitute for natural gas is uncertain at this stage because there are technical issues around its storage, transportation and end use. One major issue is that transporting hydrogen at high pressure causes steel pipelines and any other metal components of the gas infrastructure to become brittle and fail (known as 'embrittlement'). Because of this, distribution networks that use plastic pipes are expected to be able to repurpose their existing infrastructure to carry hydrogen more cost-effectively, compared with transmission networks that mostly rely on steel pipelines.

Some distribution networks are experimenting with blending hydrogen with natural gas as a means to lower carbon emissions in the gas sector. Blending trials in Australian gas networks are currently limited to 10% hydrogen.[50] Should the gas networks be repurposed to carry pure hydrogen, all gas infrastructures including metal pipes, consumer appliances and industrial processes will need to be evaluated for compatibility.

Also, hydrogen can be a distributed energy resource, meaning that it can be produced locally or close to demand centres. This would have implications on the requirements to upgrade electricity or gas networks to accommodate the use of hydrogen as reticulated gas.

In the longer term, the case for repurposing networks depends on the price of hydrogen compared with substitutes such as renewable energy. Because renewable hydrogen relies on renewable electricity as an input, and its production efficiency may also depend on continuous electricity supply rather than intermittent electricity supply, hydrogen may not be cost-effective for all gas applications where substitutes are readily available.

At this point, the economics of using hydrogen for residential consumption remains an open question. The Australian Government has set a stretch goal of producing hydrogen by electrolysis for $2 per kilogram.[51] Including typical capital investments needed to prepare sites to prepare hydrogen by electrolysis, today's renewable hydrogen can be produced for between $6 and $9 per kilogram.[52] Australia's National Hydrogen Strategy estimated the delivered price (which includes the cost of storage and transportation in addition to production) that hydrogen would need to achieve to compete with natural gas for residential heating was $1.2 per kilogram.[53] It provided a chart that demonstrated the breakeven cost of hydrogen against alternative technology for major applications in 2030 (see Figure 7).[54]

[49] International Renewable Energy Agency, *Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5ºC Climate Goal*, 2020, p.8.

[50] Energy Networks Australia, *Is Britain's hydrogen plan an aussie blueprint?*, 2021 Energy Insider, February 2021. Accessed via: https://www.energynetworks.com.au/news/energy-insider/2021-energy-insider/is-britains-hydrogen-plan-an-aussie-blueprint/

See also, Australian Renewable Energy Agency (ARENA), *Green hydrogen injection plan for VIC and SA gas grids*, March 2020. Accessed via: https://arena.gov.au/blog/green-hydrogen-injection-plan-for-vic-and-sa-grids/

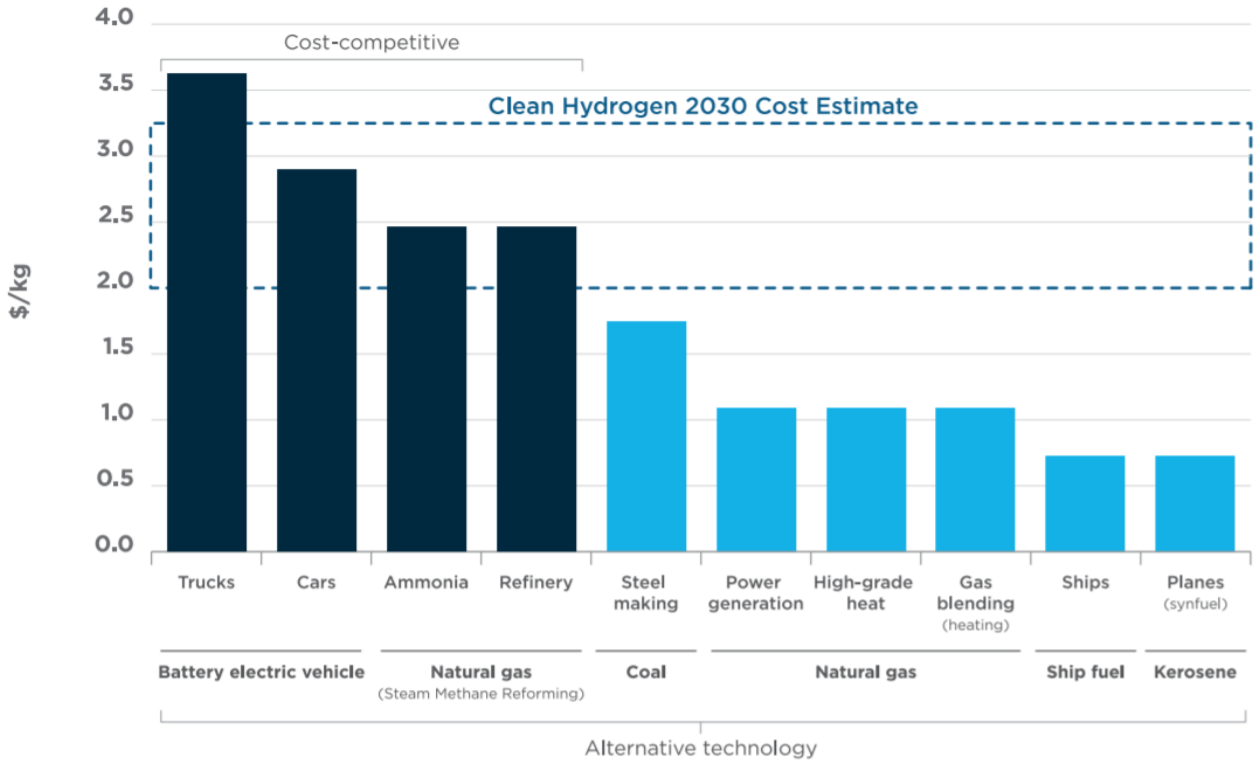
[51] Australian Government Department of Industry, Science, Energy and Resources, *Technology Investment Roadmap: First Low Emissions Technology Statement*, September 2020. Accessed via: https://www.industry.gov.au/sites/default/files/September%202020/document/first-low-emissions-technology-statement-2020.pdf

[52] ARENA, *Australia's pathway to $2 per kg hydrogen*, November 2020. Accessed via: https://arena.gov.au/blog/australias-pathway-to-2-per-kg-hydrogen/

[53] Commonwealth of Australia, *Australia's National Hydrogen Strategy*, November 2019, p.xiv.

[54] Commonwealth of Australia, *Australia's National Hydrogen Strategy*, November 2019, p.6. Chart is illustrative, as the exact breakeven point will be region-specific, and will be different when comparing to other alternatives (such as petrol or diesel).

Figure 7 Breakeven cost of hydrogen against alternative technology for major applications in 2030



Source: Australia's National Hydrogen Strategy

2.3.2 Bio-methane or biogas

Biogas is another form of renewable energy that can be used to decarbonise natural gas. Biogas is a mixture of methane, carbon dioxide and small quantities of other gases produced by anaerobic digestion of organic matter in an oxygen-free environment. Bio-methane is produced by 'upgrading' biogas to remove all gases other than methane or through the gasification of solid biomass followed by methanation.[55] Unlike biogas, bio-methane is chemically identical to natural gas and so can be used without the need for any changes in transmission and distribution infrastructure or end-user equipment.

Although the combustion of biogas or bio-methane produces carbon dioxide, the carbon in these gases comes from the organic matter that has absorbed this carbon from atmospheric carbon dioxide. Therefore, biogas production is carbon neutral and does not add to greenhouse gas emissions.

Of total bio-methane produced worldwide today, 90% is produced by 'upgrading' biogas. The main technologies for producing biogas include biodigesters, landfill gas recovery systems and wastewater treatment plants.[56] As such, the production of bio-methane also depends on the

[55] International Energy Agency, *Outlook for biogas and biomethane: Prospects for organic growth, Report extract – An introduction to biogas and biomethane*, March 2020. Accessed via https://www.iea.org/reports/outlook-for-biogas-and-biomethane-prospects-for-organic-growth/an-introduction-to-biogas-and-biomethane

[56] Ibid.

location of the organic feedstock used to produce biogas, such as crop residues, animal manure, industrial waste and wastewater sludge.[57]

Production costs for bio-methane equal the biogas production costs plus the additional costs for 'upgrading'. It is estimated that the global average cost of producing bio-methane (through biogas upgrading) today is around USD 19/MBtu.[58, 59] For comparison, the average wholesale gas price in Australia in 2020 was less than USD 6/MBtu.[60]

The economic challenge of using bio-methane as a reticulated gas lies in the costs of production and the costs of connecting biogas-upgrading facilities to the gas networks. To be cost-effective, biogas-upgrading facilities must generally be located very near to existing gas networks. There may also be diseconomies of scale with importing these gases from discrete locations in relatively small quantities.

Biogas can be used for heat or electricity generation for use onsite or for export into the electricity grid. The economics of exporting biogas into gas distribution networks would also depend on the relative cost-competitiveness of using biogas for other applications.

Because bio-methane is not currently cost-competitive against natural gas, the development of bio-methane as a natural gas replacement will depend on policies that encourage its production and use.[61]

2.4 Scenario forecasts of future energy mix

There have been several recent publications that seek to forecast future energy scenarios and determine the most cost-effective decarbonisation pathway for the energy sector based on the available technology and information. We briefly set them out in this section. It is clear from these analyses that the pathway to net zero emissions by 2050 is highly uncertain and there are multiple plausible energy scenarios. Underpinned in most of these scenario analyses is the expectation that natural gas use will decline over time to decarbonise the energy sector. The opportunity to repurpose existing natural gas networks is unknown because hydrogen production and use is not yet proven at scale.

2.4.1 AEMO's Inputs, Assumptions and Scenarios Report 2021

In July 2021 AEMO completed its consultation on its *Inputs, Assumptions and Scenarios Report 2021* (IASR). This report contains the description of the inputs, assumptions and scenarios used in AEMO's 2021–22 planning and forecasting publications, including the Electricity Statement of Opportunities, the GSOO and the Integrated System Plan.

57 Ibid.

58 MBtu represents one million British Thermal Units per hour, which is equal to about 1.055 gigajoules.

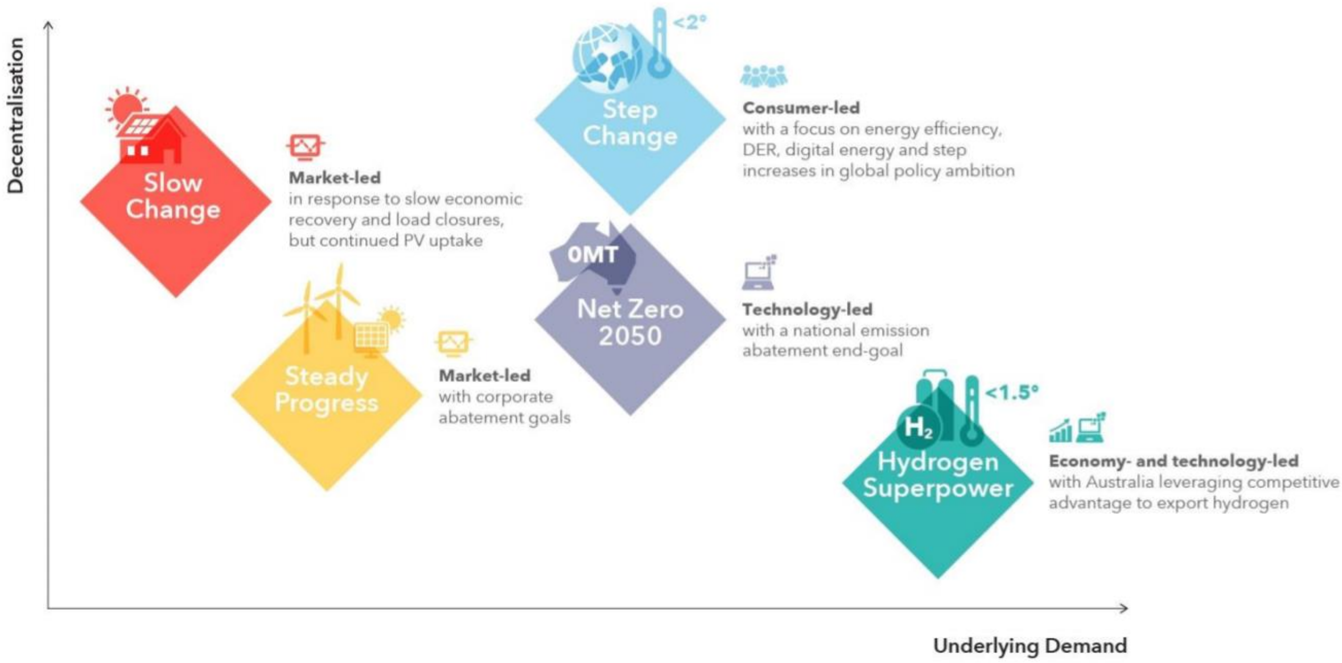
59 International Energy Agency, *Outlook for biogas and biomethane: Prospects for organic growth, Report extract – Sustainable supply potential and costs*, March 2020. Accessed via https://www.iea.org/reports/outlook-for-biogas-and-biomethane-prospects-for-organic-growth/sustainable-supply-potential-and-costs#abstract.

60 International Gas Union, *Wholesale Gas Price Survey 2021 Edition*, July 2021, p.36. Accessed via https://www.igu.org/resources/global-wholesale-gas-price-survey-2021/.

61 Ibid.

In the IASR, AEMO has identified five plausible, distinct, internally consistent scenarios that cover a broad range of potential future worlds that could materially impact the energy sector. Each future world, described through a scenario narrative, decreases the carbon intensity of the energy sector (and Australia's economy more broadly) at a different rate. The scenarios are differentiated not only by the rate of decarbonisation, but also by variations in the level of electricity consumed in the future and the extent of decentralisation of electricity supply (see Figure 8).

Figure 8 2021–22 scenarios formulated by AEMO



Source: AEMO 2021, Inputs, Assumptions and Scenarios Report 2021

Table 2.1 summarises what the five scenarios look like for how people live and work in the National Electricity Market (NEM) in 20 years (in 2040).[62]

Table 2.1 AEMO's future energy scenarios in 2040

AEMO's scenarios in 2040	Rooftop solar capacity compared with 2020	Residential heating	Industry and manufacturing	Proportion of our cars that are electric vehicles
Steady progress Power system has developed based mainly on market-led investments, with corporate goals driving economy-wide emissions abatement	Triple	Homes are still heated by ducted gas heating system, gas use in homes reduced by about 15%	Consistent with 2020 trends	One-third

[62] AEMO, *Overview 2021 Inputs, Assumptions and Scenarios Report*, July 2021. Accessed via https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-assumptions-and-scenarios-report-overview.pdf?la=en

AEMO's scenarios in 2040	Rooftop solar capacity compared with 2020	Residential heating	Industry and manufacturing	Proportion of our cars that are electric vehicles
Net zero 2050 The NEM has seen 10 years of growth in deployment of emissions-abatement technologies, and would be on track for zero emissions by 2050	Quadruple	Increasingly heating our homes with electric heat pumps and reverse cycle air-conditioning, with gas heating appliances reduced by 55% since 2020.	Over 30% powered by electricity, up from 20% electricity in 2020	Almost half
Step change Consumers have led a transformation by installing more of their own power sources, buying electric vehicles, and voting for strong global policy action to rapidly reduce carbon emissions	Quadruple	The use of gas in our homes is cut by 85% since 2020, on the path to using no gas in homes by 2050	Using nearly 20% less gas, 30% less coal and 90% less oil than in 2020	Almost 60%, and almost one-third of heavy vehicles are fuelled by hydrogen
Slow change We have not made co-ordinated efforts to reduce carbon emissions or to use more electricity across the NEM	Triple	Consumers pursue energy efficiency and switching to electric heating and appliances slowly	Limited change in industry's use of gas	20%
Hydrogen super-power The energy sector has been transformed by government policy, corporate action, and technology breakthroughs. There is also an important export market for hydrogen produced in the NEM	Five times	Houses are using 90% less gas, switching to hydrogen (54% of the change) or electricity	Reduced use of natural gas by over 65% since 2020, with a bit over half of that demand shifting to hydrogen instead	75% Almost half of all articulated trucks on the road are fuelled by hydrogen

Source: AEMO 2021, IASR Overview

2.4.2 Infrastructure Victoria's report on the future of Victoria's gas networks

Infrastructure Victoria[63] was tasked by the Victorian Treasurer to provide advice on the future of Victoria's gas networks under a range of 2050 net zero emissions energy sector scenarios. Its work is intended to inform and complement existing efforts led by the Department of Environment, Land, Water and Planning (DELWP) in devising the Victorian Gas Substitution Roadmap.

In its interim report *Towards 2050: Gas infrastructure in a zero emissions economy* published in July 2021, Infrastructure Victoria notes that 'emissions from natural gas will need to decline significantly in the coming decades to meet Victoria's net zero 2050 target and reduce the impacts

63 Infrastructure Victoria is an independent advisory body who prepares the 30-year infrastructure strategy for Victoria and prepares written advice to government on specific infrastructure.

of climate change'.[64] It also notes that 'all future infrastructure and network investment decisions should be tested for compatibility with pathways to net zero'.[65]

Infrastructure Victoria has designed four illustrative scenarios to achieve net zero emissions for gas use in Victoria by 2050 (see Table 2.2), with key variables regarding: [66]

- the technology mix – namely electrification, natural gas, hydrogen and biogas
- the mechanism by which net zero emissions are achieved – that is whether emissions are eliminated or managed by solutions such as carbon offsets or carbon capture and storage (CCS).

Table 2.2 Summary of Infrastructure Victoria's designed scenarios

Scenario A: Zero emissions electrification – no natural gas	Scenario B: Net zero emissions electrification supported by natural gas	Scenario C: Zero emissions hydrogen with biogas and electrification	Scenario D: Net zero emissions hydrogen with biogas and electrification
• Almost full electrification using renewable sources, utility-scale battery storage and some pumped hydroelectric • Very little natural gas except where it is irreplaceable – and none by 2050 • No CCS by 2050	• Extensive electrification with renewable sources, significant small-medium battery storage and limited pumped hydroelectric • Some natural gas to support the renewable electricity system and some industrial uses • Made net zero by CCS and offsets	• Hydrogen using renewable sources really takes off as a substitute for natural gas • Some waste to energy, biogas and renewable electricity sources with some battery storage • No CCS • No natural gas by 2050	• Hydrogen using both renewable sources and coal with CCS • Some waste to energy and biogas and renewable electricity sources with some battery storage • No natural gas by 2050

Source: Infrastructure Victoria interim report (July 2021)

Infrastructure Victoria is currently refining its analysis of scenarios to combine promising technologies and policies likely to help meet Victoria's interim emissions targets. Its final report is due by the end of 2021.

2.4.3 Grattan Institute's *Flame Out* report

In its *Flame Out: the future of natural gas report*, Grattan Institute shows that a combination of economics and environmental imperatives imperil the natural gas industry.[67] It suggests that natural gas will inevitably decline as an energy source for industry and homes in Australia. It also considers that it would be more expensive to replace retiring coal-fired power stations with gas than to switch to more renewable energy such as wind and solar.

Grattan Institute has compared the cost of switching all small users to electricity against the costs of operating gas networks unchanged over 20 years in New South Wales (NSW), Victoria and

64 Infrastructure Victoria, *Towards 2050: Gas infrastructure in a zero emissions economy*, July 2021, p.13.

65 Ibid, p.44.

66 Ibid, pp.27-29.

67 Grattan Institute, *Flame out – the future of natural gas*, November 2020.

South Australia.[68] Grattan Institute finds that switching to electricity is more expensive than sticking with natural gas in these jurisdictions – about 65% more in NSW, 40% more in South Australia and double in Victoria.[69]

In Victoria, the large household winter gas heating load means that a broad gas-to-electricity switch can move peak electricity demand from summer to winter and increase it by about 40%. This would affect the electricity system and is likely to place upward pressure on electricity prices.[70] Appliance costs and connection upgrades, rather than electricity grid upgrades, are the main barrier to electrifying NSW and SA small-user gas loads.[71]

Grattan Institute suggests that households would save money and Australia would reduce emissions if new houses in NSW, Queensland, South Australia and the ACT were all-electric, and recommends that governments in those jurisdictions impose a moratorium on new gas connections.

2.4.4 Frontier Economics' report for the Australian gas industry

Frontier Economics undertook a study on the benefits of gas infrastructure to decarbonise Australia for the Australian gas industry associations in September 2020.[72] The study aimed to estimate the value of the gas infrastructure in 2050, accounting for Australia's carbon emissions commitments.[73] Frontier Economics developed and considered four gas infrastructure scenarios:[74]

- **Base Case** – represents a 'business-as-usual' outcome for the electricity and gas sectors in 2050. There are continued emissions associated with the end-use of natural gas in this scenario. This scenario is used to compare costs and benefits against other scenarios.
- **Electrification scenario** – all end-use gas users will switch from gas supply to electricity supply where possible. Under this scenario, industrial gas customers are assumed to rely on a mix of energy sources to meet their energy needs, including grid-source electricity, distributed energy resources, distributed solar thermal plant and hydrogen produced from onsite electrolysers supplied with grid-source electricity. Under this scenario, gas infrastructure will no longer be used.
- **Renewable Fuels scenario** – hydrogen produced using alkaline electrolysis replaces all end-use natural gas consumption. In this scenario, the hydrogen electrolysers are assumed to be located close to renewable generation sites with a new network of hydrogen transmission pipelines that transport hydrogen to existing natural gas distribution networks for distribution.

68 Grattan Institute, *Flame out – the future of natural gas*, November 2020, p. 48.

69 Ibid, pp. 48-49.

70 Ibid, pp. 45-47.

71 Ibid, p.48.

72 Frontier Economics, *The Benefits of Gas Infrastructure to decarbonise Australia – A report for the Australian gas industry*, September 2020. Available at https://www.energynetworks.com.au/resources/reports/2020-reports-and-publications/the-benefits-of-gas-infrastructure-to-decarbonise-australia-frontier-economics/

73 Ibid, p.3.

74 Ibid, p.3.

- **Zero-carbon Fuels scenario** – hydrogen produced using steam methane reforming (SMR) of natural gas with carbon capture and storage replaces all end-use natural gas consumption. This scenario is equivalent to the Renewable Fuels scenario except for a different method of hydrogen production. It is also assumed that the hydrogen production plant will be located near the connection points of the existing gas distribution network. This way, existing gas transmission networks can be utilised to transport natural gas to hydrogen production plant and the hydrogen produced from the plant can be delivered to customers through existing gas distribution networks.

Frontier Economics' analysis focused on comparing the net present value of the difference in annual costs in 2050 between each of its designed scenarios and the Base Case rather than the costs incurred during the transition to the scenarios it assessed.[75] Based on its analysis, Frontier Economics found that the Zero-carbon Fuels scenario is lower cost than both the Renewable Fuels scenario and the Electrification scenario, and all three scenarios are more costly in 2050 than the Base Case. [76]

2.5 Summary of the implications of gas substitution methods

To reach a net zero emissions target by 2050, natural gas applications are likely to be replaced by different technologies (electricity, hydrogen, biogas or bio-methane) or require carbon capture and storage and carbon offsets to accommodate some natural gas consumption. It is unlikely that natural gas will be substituted by one single technology. In this section, we examine how three key gas substitution methods, which are commonly considered in future energy scenario forecasts, would affect energy users and network businesses.

2.5.1 Electrification

Electrification refers to the replacement of gas use with electricity. It is expected to play a significant role in decarbonising the energy sector as more renewable electricity sources become available. Electrification is a core strategy in many jurisdictions for reducing emissions associated with natural gas. One notable example is the ACT. Table 2.3 summarises the implication of using electricity instead of natural gas for different parties.

Table 2.3 Implications of replacing natural gas with electricity

Residential consumers
• Residential gas appliances can be replaced by electric appliances currently available in markets. This will likely happen at the point when consumers need to replace their existing gas appliances or when consumers feel that using electricity is more affordable than using gas. • Vulnerable, low-income consumers may not be able to switch from gas to electricity due to the costs of buying new appliances. However, some governments currently provide subsidies to lower-income households to replace inefficient heaters to energy-efficient reverse cycle system and may continue to do so.[77]

75 Ibid, p. 4.

76 Ibid, p. 5.

77 See for example, the Victorian Governments' Home Heating and Cooling Upgrades Program delivered by Solar Victoria, https://www.heatingupgrades.vic.gov.au.

- Renters are unlikely to be able to replace gas appliances with electric appliances at their rental properties without their landlords' agreement.

Commercial and industrial consumers
• Industrial users may not be able to use electricity for their business operations, especially those that use natural gas as a chemical feedstock or for industrial process heating at high temperatures. • Industrial users who are able to convert their operations to using electricity may need to make new capital investments in industrial appliances and in adjusting their processes.
Distribution gas networks
• If a large proportion of residential consumers reduce their gas demand due to electrification, distribution gas networks may become significantly under-utilised. • The opportunities to repurpose the gas networks to transport other gases may be limited if the pace of electrification is too quick before the use-cases for hydrogen or bio-methane are proven.
Transmission gas networks
• If a large proportion of residential consumers reduce their gas demand due to electrification, transmission gas networks that service a high proportion of residential consumers may become significantly under-utilised. • The rate of decline in demand can be expected to be sharper for transmission businesses compared with distribution businesses if they lose large industrial gas users that are connected directly to the transmission network, noting that industrial users who use gas as a feedstock would likely have a more inelastic demand for gas compared with residential users. • To the extent that gas-power generators remain essential to maintain the reliability of electricity supply, and that some industrial users continue to use natural gas for their business operations, there will still be a limited role for transmission network to continue supplying gas network services to those customers provided that the revenues earned cover ongoing operating costs.
Electricity networks
• Any shift towards electricity in place of gas will likely have a significant impact on electricity networks, most notably in states with colder climates. Peak electricity demand would change from summer to winter and this may necessitate network capacity reinforcements, which may in turn risk increasing electricity prices.

2.5.2 Substituting natural gas with hydrogen

As discussed in section 2.3.1, the potential for hydrogen to substitute for natural gas is uncertain because many questions remain about its storage, distribution and end use. Table 2.4 summarises the implications of using renewable hydrogen instead of natural gas for different parties.

Table 2.4 Implications of substituting natural gas with renewable hydrogen

Residential consumers
• Consumers can't switch from natural gas to hydrogen at this point. There are no hydrogen-enabled appliances available in the market. Standard residential gas appliances are expected to be able to use natural gas blends that contain a concentration of up to 10% hydrogen without adjustments.[78] However,

[78] Australian Gas Infrastructure Group, *Submission to Victoria's Gas Substitution Roadmap consultation*, August 2021, p..7. Accessed via: https://s3.ap-southeast-2.amazonaws.com/hdp.au.prod.app.vic-engage.files/4016/2925/9902/Australian_Gas_Infrastructure_Group.pdf

switching to pure hydrogen as a fuel source would require consumers to use hydrogen-enabled appliances, including gas meters.

- Using hydrogen as a reticulated gas may also entail higher gas access prices because gas networks would need to be upgraded to some degree to transport hydrogen.

Commercial and industrial consumers

- Some commercial and industrial consumers may be able to use hydrogen instead of natural gas as chemical feedstock or for process heating, but some may not. The technical and economic feasibility of converting commercial and industrial consumers to the use of renewable hydrogen have not been demonstrated.
- Industrial users who are able to convert their operations to using hydrogen are likely to need to make new capital investments in industrial appliances and adjust their processes given the different chemical properties of hydrogen.

Distribution gas networks

- Distribution gas networks have progressively replaced their old pipelines with plastic pipelines and these plastic pipelines are generally considered suitable for transporting hydrogen. However, they may need to replace any metal parts within their networks that may be exposed to hydrogen (embrittlement risk).
- Some distribution networks are currently trialling the transportation of natural gas blends that contain a concentration of up to 10% hydrogen.

Transmission gas networks

- Steel or metal transmission pipelines are common in gas transmission networks. They are likely to be subject to embrittlement risk when transporting hydrogen, particularly under high pressure. This makes it difficult to repurpose existing gas transmission networks to carry hydrogen (or even low natural gas-hydrogen blends) without extensive modifications.
- Existing transmission networks may not exist in areas where renewable hydrogen production occurs (which is likely dependent on the proximity to a renewable energy and water source). Hydrogen transmission may be more expensive than transporting water or electricity. If it is demonstrated to be more economical to have hydrogen production facilities near sources of demand, then the role of existing gas transmission networks in carrying hydrogen may be limited.
- Gas transmission networks may be used to carry carbon dioxide for carbon capture and storage services.

Electricity networks

- Having hydrogen as an energy source for consumers may ease their reliance on electricity networks for their energy needs. This means less investments would be required to increase the capacity of the electricity networks, compared with a scenario where all consumers switch from gas to electricity.
- Reinforcement of the electricity transmission or distribution networks may nevertheless be required to facilitate large-scale renewable hydrogen production if those production facilities are located far from electricity sources.
- Like natural gas, hydrogen may be used to power gas-fired generators, potentially playing the role of maintaining security of electricity supply when variable renewable energy generation is low.

2.5.3 Substituting natural gas with bio-methane

As explained in section 2.3.2, bio-methane is indistinguishable from natural gas and so can be used without the need for any changes in transmission and distribution infrastructure or end-user equipment. Table 2.5 summarises the implication of using bio-methane instead of natural gas for different parties.

Table 2.5 Implications of substituting natural gas with bio-methane

Residential consumers
• Consumers can continue using gas as they normally do now, without having to change their appliances. • Bio-methane would likely cost more than natural gas or renewable electricity, due to production costs and the lack of supply relative to demand. This may make it more likely that consumers would opt for alternatives.
Commercial and industrial consumers
• Commercial and industrial consumers can use bio-methane as they do with natural gas now, without having to change their appliances or processes, but potentially at a higher cost.
Distribution gas networks
• Little or no modifications are required for natural gas infrastructure to transport bio-methane. However, additional investments may be required to connect bio-methane production facilities to the distribution networks.
Transmission gas networks
• Little or no modifications are required for natural gas infrastructure to transport bio-methane. However, existing transmission networks may not be accessible in areas where bio-methane production occurs (which is likely dependent on where organic feedstock are).
Electricity networks
• Like natural gas, having bio-methane as an energy source would ease consumers' reliance on electricity. This means less investments would be required to increase the capacity of the electricity networks, compared with a scenario where all customers switch from gas to electricity.

3 Impact of declining gas demand on gas customers and regulated gas network businesses

The demand for gas network services hinges on the demand for natural gas or renewable gases. If renewable gases are not commercially viable soon enough, this may leave policy makers and consumers with the only option to substitute natural gas with electricity to realistically decarbonise before 2050.

If renewable gases do not become commercially viable a timely manner, there is the risk that there may be a substantial decline in the demand for gas network services in the period leading up to 2050. This section explains what this may mean for consumers and regulated businesses, exploring:

- the effect on shared fixed network costs of having fewer customers (section 3.1)
- how future gas customers could bear the cost of unpaid past investments (section 3.2)
- the potential for stranding of gas networks (section 3.3)
- how price volatility or uncertainty could further reduce demand (section 3.4).

3.1 Fewer customers to share fixed network costs

Gas access prices are derived from regulated businesses' maximum allowed revenues divided by forecast demand. As more customers leave the gas network, there will be fewer customers to share the fixed costs of gas networks. All else being equal, gas access prices will go up when there is less gas demand.

3.2 Cost burden of unpaid past investments may be shifted to future gas customers

Gas network businesses invest in long-lived assets in the expectation of recouping the costs from customers over a certain period of time – typically assumed to be the technical life of the assets. In the case of major pipeline assets, technical asset lives can be up to 80 years.

Customers who leave the gas networks may not have contributed sufficient incremental revenue to fully pay off the capital investments incurred for their gas connection and network services. Consequently, the remaining customers in the gas network will have to shoulder that burden as those costs remain in the regulatory asset base (RAB) until fully depreciated. This raises an intergenerational equity and fairness issue.

3.3 Potential economic stranding of gas infrastructure assets

With the prospect of a shrinking customer base and increasing competitiveness of alternative energy sources, regulated gas businesses face a risk that they may not be able to recover the costs of their efficient investments. There is a risk of network assets becoming economically stranded.

Stranded assets are investments that are no longer able to earn an economic return prior to the end of their economic life as assumed at the investment decision point. Their economic life may be curtailed due to either changes in technology, regulation, market changes, or some combinations of these.

Economic stranding of assets is caused by a change in relative costs or prices. It refers to unused or underutilised assets to such a degree that the owner cannot recover a full return of and on capital. It is distinct from physical stranding, which refers to an asset that ceases to be used because of reasons such as obsolescence, failure, damage etc. The regulatory framework allows for assets to stay in the RAB even if they have become physically stranded, although there are provisions in the NGR to allow the exclusion of a redundant asset that is no longer used from the RAB.[79]

Provided that customers can switch from gas with little or no transaction cost, end-user gas prices (which includes gas access prices amongst other things) would be constrained by customers' willingness to pay for gas and/or the prices offered by competitive gas substitutes such as electricity. If the constraints on gas prices become sufficiently strong such that gas becomes relatively uncompetitive, then with falling demand, regulated revenues for regulated businesses may not support full cost recovery of the RAB. In this scenario, the network business will under-recover the amounts it has invested over the life of its assets, including a normal rate of return on those capital investments.

There is little a network business can do to counteract the effects of a declining customer base, other than limiting new expenditures and managing prices to minimise disconnections by customers. However, the costs to maintain a gas network do not decrease in proportion to gas demand decline.[80] The pipeline assets are likely to remain in use and the regulated businesses will incur ongoing maintenance and replacement costs to maintain safe and reliable network services for the remaining customers on the network, subject to any partial shutdowns of the network.

When faced with a material stranded asset risk, network businesses may want to bring forward the cost recovery of their investments to reduce the expected losses they may face in the future. Barring that, network businesses may seek additional compensation for carrying this risk or they may not have the right incentives to make efficient investments in the network. All else being equal, bringing forward the cost recovery of the RAB, or paying compensation to network businesses for stranded asset risk, will increase gas access prices.

3.4 Price volatility or uncertainty may drive further decline in demand

Gas appliances typically last for 10-15 years. Consumer expectations of gas prices over that 10-15 year period are a factor in their investment decision. If future gas demand is expected to fall substantially or is highly uncertain, with corresponding expectations of price increases or price uncertainty, consumers may perceive a higher risk or cost associated with their investment in gas appliances.

Material price increases caused by a shrinking customer base, or expectations of future price increases, can further incentivise customers to leave the gas network, compounding the effects of declining gas demand. This is what we commonly refer to as the 'utility death spiral'.

[79] NGR, r. 86.

[80] Lucas Davis, Catherin Hausman, Energy Institute at Haas, *Who will pay for legacy utility costs?*, June 2021, p.2.

4 Potential options to address the implications of falling gas demand

In light of the uncertainty in future gas demand, we will need to balance the interests of regulated businesses and gas consumers, as well as the interests of current consumers versus future consumers. This will require continuing assessment as community views, government policies and the cost of gas and alternative technologies continue to develop.

The long-term role of gas pipelines is unclear at this stage. In order to determine the appropriate regulatory options, we must consider the full range of foreseeable scenarios. This includes the most extreme scenarios, such as a total abandonment of gas networks.

The impact of declining gas demand on gas access prices is two-fold – higher network costs per customer due to fewer customers to share the fixed costs, and increasing stranded asset risk that may warrant price adjustments. While we may not be able to influence the pace at which customers leave the gas networks, we may be able to mitigate the price impact that remaining gas customers face if we act early and prudently.

This section outlines potential regulatory options for addressing decreasing gas demand by examining

- the existing gas regulatory framework under the law and rules (section 4.1)
- eight potential options for dealing with demand uncertainty (sections 4.2-4.9)
- how other regulators have dealt with issues of declining demand and stranded asset risk (section 4.10)
- if governments or taxpayers should pay for stranded assets (section 4.11)
- our preliminary views and considerations of the regulatory options (section 4.12).

4.1 The national gas regulatory framework

The national gas regulatory framework in the National Gas Law (NGL) and National Gas Rules (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.[81] (emphasis added).

[81] See NGL, Revenue and pricing principles, section 24(2).

In competitive markets, firms take on the risk of the price and quantity of sales. Where there is a material stranded asset risk, firms would defer entry into the market until prices have risen to a level that provides an acceptable rate of return after accounting for the stranded asset risk (i.e. a risk premium). Alternatively, firms mitigate stranding risk by entering into long-term contracts with customers.[82]

Economic regulation is designed to provide a functional proxy for competitive markets. The regulatory settings are designed to provide appropriate incentives for regulated businesses to invest by preserving the expectation of recovering the efficient costs of their investments, including a normal return.

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

1. remove, or substantially reduce, the prospect of under-recovery of costs, or
2. compensate the regulated business for carrying this risk.

Both approaches will inevitably raise prices for gas consumers, as opposed to doing nothing to address stranded asset risk. There may be other factors that have an offsetting effect on prices, meaning that prices do not necessarily rise materially relative to the previous regulatory period. Therefore, our approach in addressing stranded asset risk is a balancing act between preserving the right incentives for network investments and maintaining price affordability of gas network services, avoiding price shocks and further gas substitution where possible.

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.[83] The benefits of this approach are discussed in detail in section 4.2.

Exposing regulated businesses to some stranded asset risk may be desirable to reduce discretionary network expenditures given the current levels of uncertainty. However, stranded asset risks may distort the incentives that regulated businesses face in making new investments to meet service obligations for existing consumers or increase the overall costs of service. For example, a regulated business may limit or defer its network investments even if they are efficient, or opt for investments that have higher certainty in terms of cost recovery, but which may result in higher long-term costs of service. It may seek to purchase insurance to protect itself from the risk, if such insurance product is available or if any insurer is willing to underwrite the risk at reasonable costs, and these costs may be transferred to consumers. Provided there is a reasonable prospect to recover the cost of these investments, the regulated business may also be incentivised to prevent its assets from stranding by exploring innovative technologies that can replace natural gas as a reticulated gas.

82 Jemena Gas Networks, *Revised 2020-25 Access Arrangement Proposal – Attachment 8.3 – Response to the AER's draft decision – Using asset lives to manage stranded asset risks*, prepared by Incenta, January 2020, pp.15-16.

83 See AER, *Discussion paper, The allowed rate of return, compensation for risk and the use of data when judgement is required*, February 2018, p.93; and AER, *Discussion paper, Equity Beta*, March 2018, p.29.

In our view, the NGL guiding revenue and pricing principle that regulated businesses should be provided with a *reasonable opportunity* to recover at least the efficient costs they incurred in providing services does not mean gas consumers must guarantee that the regulated businesses recover their costs under any circumstances. That is, regulatory depreciation or risk compensation cannot be adjusted without constraint to guarantee cost recovery for the regulated businesses. We must have regard to consumers' interest in having affordable and stable or reasonably predictable gas access prices to encourage their use of the gas infrastructure. Having said that, it is fair to note that regulated businesses also have an interest to maintain price affordability to avoid further decline in gas customer numbers.

We must carefully consider what regulatory actions may be appropriate to promote the efficient investment in, operation and use of the gas networks while maintaining reasonably affordable and predictable gas access prices, both of which are in the long-term interests of gas consumers, in light of the uncertainty in future gas demand we face now. We will do so with regard to the specific circumstances of the regulated business and the scale of price adjustments that can be reasonably made without creating price shocks. We discuss the potential options in this section. These are not mutually exclusive (i.e. we may use a combination of these options) and not all of them would be warranted at the same time or now.

4.2 Option 1: Adjusting regulatory depreciation

Bringing forward the cost recovery of the efficient investments that regulated businesses have already made would increase the certainty that incurred costs would be recovered, thereby reducing stranded asset risk and the potential need for material upwards price adjustments in the future.

Accelerating regulatory depreciation, either by shortening the period over which assets are depreciated or by increasing the rate at which the assets are depreciated over time, alters the apportionment of risk between consumers and the regulated businesses, and between current and future consumers.[84] It increases the revenue requirement and the amount that current consumers pay via network charges, holding all other factors unchanged. The increase in charges passed through to current consumers represents an increased allocation of the risk of asset stranding to current consumers and a decreased allocation of the risk to businesses and future consumers.

Under the NGR, regulatory depreciation is determined by:

- the level of efficient capital expenditure that is incorporated into the RAB (conforming capital expenditure)
- the economic life or the time taken until the asset is fully depreciated
- the depreciation profile or pattern of depreciation over time.

Rule 89(1) of the NGR stipulates that the depreciation schedule should be designed:

84 Regulatory depreciation can be increased by shortening the period over which assets are depreciated, which is to define a shorter economic life for the asset than what its technical useful lie would be, assuming a straight-line depreciation. Alternatively, regulatory depreciation can be increased by accelerating the recovery of a portion of costs, creating a front-loaded instead of flat depreciation profile over time.

(a) so that reference tariffs will vary, over time, in a way that promotes efficient growth in the market for reference services[85]

(b) so that each asset or group of assets is depreciated over the economic life of that asset or group of assets[86]

(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[87]

(d) so that (subject to the rules about capital redundancy), an asset is depreciated only once[88]

(e) so as to allow for the service provider's reasonable needs for cash flow to meet financing, non-capital and other costs.[89]

Rules 89(1)(b) and (c) provide flexibility for a depreciation schedule to change where necessary to allow cost recovery and to generate efficient prices, as new information becomes available. Rule 89(1)(a) requires the regulator to consider how the changes in the depreciation schedule, and in turn the tariffs, would encourage the use of the asset (demand side) and provide the right incentive for efficient investments to facilitate the growth of the market (supply side). We must balance the effect on both sides when adjusting the depreciation schedules, taking into account consumers' willingness to pay and the regulated businesses' incentives to invest.

Our standard approach uses a real straight-line method to calculate regulatory depreciation, and the economic life for a particular asset is assumed to be its technical useful life.[90] However, ultimately, the expected economic life of an asset should reflect the period over which the asset can be reasonably expected to be in use economically. In the case of long-lived assets, this would mean a shortening of asset lives if demand is expected to end before the technical life ends.

Specifying shorter asset lives for *new* pipeline assets could preserve the effective incentives required for regulated businesses to make new investments. On the other hand, shortening the remaining asset lives of existing assets (i.e. the RAB) could potentially limit the incentive for the regulated businesses to make new investments. This is because they may prefer to prioritise cost recovery of the existing RAB over adding new capital expenditure to the RAB while avoiding price increases that may encourage further customer disconnections.

Also, as noted by the Economic Regulation Authority (ERA) in its recent access arrangement decision for the Dampier to Bunbury Natural Gas Pipeline (DBNGP), 'the proposal to cap economic life... may be construed as being contrary to the long-term interests of consumers. The reduction in economic lives results in an increase in regulated tariffs with no apparent consumer benefit. While generally the provision for a service provider to recover the costs of sunk investments may have a long-term consumer benefit through supporting incentives for future investments … it is difficult to see any such benefit in the circumstances of the DBNGP, which

85 NGR, r. 89(1)(a).

86 NGR, r. 89(1)(b).

87 NGR, r. 89(1)(c).

88 NGR, r. 89(1)(d).

89 NGR, r. 89(1)(e).

90 With straight-line depreciation, an asset's cost is depreciated the same amount for each access arrangement period in real terms.

DBP presents as being a declining business'.[91] Therefore, it may be construed as contrary to the long-term interests of gas consumers to shorten the asset lives of existing assets if the benefits for consumers in doing so are not demonstrated.

When gas consumption per customer is declining and the competitiveness of electricity as a substitute for gas is increasing, a price path that declines rather than increases could promote efficient use of the pipeline assets. The increasing price sensitivity of gas over time would suggest that a front-loaded depreciation profile, which allows a higher portion of costs to be recovered earlier (while price sensitivity is lower compared to later), would mitigate the potential price increases in the future, thereby encouraging fewer customers to leave the gas networks overall.

How we adjust the regulatory depreciation schedules, in terms of the length of asset lives and the rate of depreciation, reflect the degree of stranded asset risk allocation between regulated businesses and consumers based on available information. What is considered reasonable will depend on the surrounding circumstances and community views. We explore several ways to adjust regulatory depreciation in section 4.12.

Pros of adjusting regulatory depreciation:

Accelerating regulatory depreciation changes the timing of cash flow to the regulated gas network businesses but does not change the value (in net present value terms) of the costs that regulated businesses recover. It does not add to the costs of providing network services or gas access prices in net present value terms.

Regulatory depreciation can be reviewed at each access arrangement review and it can be adjusted as circumstances change in the future. It can be calibrated at later time intervals to address any material estimation errors made previously. Apart from the risk of discouraging gas consumption with a price increase (or lack of price reduction), which depends on how much accelerated depreciation we consider reasonable with respect to price affordability, there is little downside in accelerating depreciation to effectively create a price buffer for the future.

It may be an opportune time to accelerate depreciation now given interest rates (and rate of return) are relatively low, which may offset some price impact of accelerated depreciation. Also, with an expectation that interest rates may increase in the future, there is an argument that accelerating depreciation would help smooth prices across access arrangement periods and result in greater price stability.

Increasing regulatory depreciation to recover more of the sunk costs when there are more customers to share the costs can help maintain intergenerational equity by ensuring future customers are not subject to unreasonably high gas access prices if demand does fall substantially. As such, accelerating depreciation may not only increase certainty in cost recovery for regulated businesses, but also in future price paths for consumers.

Another scenario for consideration is where incurring expenditure to make regulated gas pipelines capable of carrying hydrogen is assessed as efficient under the regulatory framework. In this instance, increasing regulatory depreciation now may provide for reduced price impacts associated with a transition to hydrogen.

[91] ERA, *Final decision on proposed revisions to the Dampier to Bunbury Natural Gas Pipeline access arrangement 2021 to 2025*, April 2021, p. 357.

Cons of adjusting regulatory depreciation:

Changing regulatory depreciation, by changing the asset lives of the RAB assets or increasing the pace of depreciation, may increase access prices for consumers in the short term. Consumers are generally more sensitive to price increases today compared to the future. This may cause consumers to disconnect from gas, if the price impact is high.

Because of the intergenerational nature of gas customers, the net present value of the total costs that consumers need to pay for gas network services over time may change if regulatory depreciation is adjusted. For long-term customers, bringing forward depreciation means they pay more today but less in the future. Overall, they pay the same amount of costs. However, for short term customers who intend to leave the gas network soon, accelerating depreciation would mean paying more than they otherwise would have.

Adopting a policy of accelerating depreciation in response to declining demand without some pre-defined limits could create an expectation of potentially large or repeated increases in future gas access prices in response to changes in expected demand. The threat of future possible price rises may have a chilling effect on consumers' investments in gas appliances that rely on the gas network. This could hasten the decline in demand for gas network services.

4.3 Option 2: Compensating for stranded asset risk

We could provide ex-ante compensation to the network businesses for the expected loss from a stranded asset risk in the form of a business-specific cash payment. Compensation would be calculated based on the probability of the stranded asset risk eventuating and the value of the stranded assets. The compensation amount will also depend on the extent to which other risk mitigation options, such as accelerated depreciation, have been adopted to reduce the risk.

Consumers would not be paying for the stranded assets in the event that the assets are economically stranded, but they would nevertheless be paying higher gas access prices to compensate regulated businesses for the risk.

We (and the ACCC) have taken a theoretically based approach to rate of return and stranded asset risk in the past. While we have not found the risk to be material to date, to the extent that the risk warrants any regulatory action, we expressed the view that it should not be compensated through the regulated rate of return, but in the form of a cash payment for the expected loss from the risk. This is on the basis that stranded asset risk is a non-systematic expected loss and therefore it should be accounted for in cash flow compensation and not in the cost of capital.

Pros of providing stranded asset risk compensation:

Absent any regulatory depreciation adjustments, providing ex ante cash flow compensation for the regulated businesses to bear stranded asset risk may maintain the expectation the businesses will have an opportunity to recover its efficient costs. This may thereby provide the incentives necessary for efficient investments in the gas networks.

Cons of providing stranded asset risk compensation:

It is extremely challenging to estimate the probability and consequences of a gas network becoming stranded, and in turn the actuarially fair compensation for the stranded asset risk. There can be material windfall gains or losses if the estimated compensation for stranded asset risk is inaccurate, or if the risk eventuates earlier or later than anticipated or does not occur at all. Customers are not able to claw back the compensation they have paid if the extent of asset stranding was misjudged. Conversely, there will be a windfall gain to consumers if the compensation paid is not commensurate with the value of the stranded assets when the stranding event occurs. If we were to choose to compensate for stranded asset risk, how we estimate the compensation will be a very contentious and challenging issue in access price reviews.

With so much uncertainty about future gas demand and the potential of renewable gases, the risk of asset stranding is highly unpredictable. This uncertainty creates a risk of overestimating compensation. Choosing to compensate for stranded asset risk rather than accelerated depreciation gives us less flexibility to adjust prices in response to new information in the future.

We don't view stranded asset risk as systematic, so we do not consider it appropriate to compensate this risk via increasing the rate of return instead of providing a business-specific cash payment. There is also an impediment in doing so because the AER publishes a Rate of Return Instrument every four years under the relevant energy laws, and this instrument determines how the regulated rate of return will be calculated for all regulatory determinations made over its four year life.[92] The Rate of Return Instrument is binding on the AER and regulated service providers and it provides the AER with no discretion in its application (i.e. it is purely formulaic in its application).The 2018 Rate of Return Instrument specified a single rate of return approach to be applied at each electricity and gas regulatory determination until its replacement which is expected in December 2022.[93]

It may be possible for the AER to set a gas-specific regulated rate of return methodology or Rate of Return Instrument in the future. However, this would also likely apply across all regulated gas businesses that may be facing markedly different market conditions and stranded asset risks.

4.4 Option 3: Removing capital base indexation

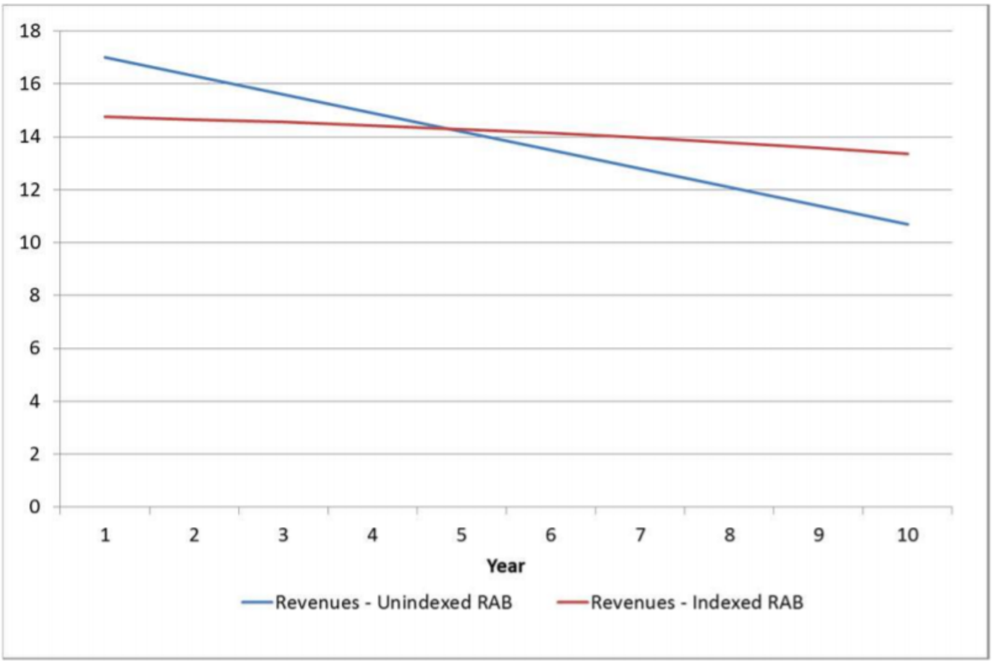
Removing indexation of the RAB (and allowing a nominal rate of return) can speed up the cost recovery of investments. Our current regulatory approach is to index the RAB with the amount of compensation for inflation that customers should pay regulated businesses. We compensate regulated businesses with a nominal rate of return, but we make a negative revenue adjustment to net off the compensation for inflation to avoid double counting. In effect, we add inflation compensation into the RAB, while providing a real rate of return to the regulated businesses. This effectively defers the regulated businesses' cost recovery of the compensation for inflation, which forms part of the required return on capital.

If we stop indexing the RAB, the return on capital provided to the regulated businesses will be based on the nominal rate of return. This means, regulated businesses recover a greater proportion of revenues sooner and prices would be higher in the short to medium term. Figure 9 shows the revenue paths of an indexed RAB approach with a real rate of return and an unindexed RAB approach with a nominal rate of return.

92 NGL, chapter 2, part 1, subdivision 2, cl. 30D; NEL, Part 3, division 1B, subdivision 2, cl. 18I.

93 During the development of the 2018 Rate of Return Instrument, we considered the difference in exposure to systematic risk between gas pipelines and electricity network businesses is not material enough to reasonably justify different equity beta benchmarks to calculate rate of return for gas businesses. We considered that stranded asset risk could be dealt with using accelerated depreciation instead.

Figure 9 Revenue path example – indexed vs unindexed RAB approaches ($nominal)



Source: AER analysis.

Indexation of the RAB leads to a somewhat higher asset valuation during an asset's life and therefore a higher overall RAB value in nominal terms. However, it also leads to smoother revenue recovery. It typically reduces the increase in revenues that invariably happens when assets are replaced at the end of their useful life, which promotes consumer's investment and consumption decisions by avoiding or reducing price shocks. We have maintained the approach of indexing RAB with inflation consistently across electricity and gas networks in the past.[94]

Pros of removing capital base indexation:

Where future gas demand is highly uncertain or expected to decline materially, removing indexation of the RAB avoids deferring cost recovery of required revenues into future periods in which there may be fewer customers, lower demand and higher risks of economic stranding. It does this while being net present value neutral. While revenues are higher in the short term, they are lower in the future (due to lower regulatory asset base) and the overall value of these cash flows is unchanged.

Removing indexation of the RAB can achieve a front-loaded cash-flow profile, akin to accelerated depreciation.

Cons of removing capital base indexation:

Currently, the RAB is maintained in real terms through time via its indexation for inflation. Depreciation is then calculated based on this real value over the economic lives of the regulatory assets. This means the RAB value through time should approximately reflect its real economic value. By removing indexation of the RAB, the RAB would be maintained in nominal terms and its

[94] See AER, *Draft position on regulatory treatment of inflation – Inflation review 2020*, pp. 71–82 and 138–140; AER, *Final position on regulatory treatment of inflation – Inflation review 2020*, December 2020, pp.66- 67.

real value would be reduced through time due to the effects of inflation. The cumulative impact of inflation on the real RAB value over time would be significant. It would also mean the network charges consumers face would not move with inflation where (typically) their income does.

In addition, the change in the real RAB value over time would vary according to actual inflation outcomes. Given inflation is inherently uncertain and can change unexpectedly, future (real) RAB values and real prices could be hard to predict for energy consumers.

A change in the treatment of inflation in the gas sector may have wider policy implications because the same approach may be introduced in electricity and other regulated sectors for regulatory consistency. We consider that a departure from targeting the real rate of return would be a fundamental change to the regulatory framework that has operated successfully and has been tested over many years.

4.5 Option 4: Sharing costs under capital redundancy provisions

There is scope for regulated businesses and their users to negotiate an allocation of the stranded asset risk between them by using the capital redundancy provisions in the NGR.[95]

The NGR provides that an access arrangement may include a mechanism for sharing costs associated with a decline in demand for pipeline services between the service provider and users.[96] Prior to requiring or approving such a mechanism, the AER must take into account the uncertainty such a mechanism would cause and the effect the uncertainty would have on the service provider, users and prospective users.[97]

The NGR also provides that a full access arrangement may include a mechanism to ensure that assets that cease to contribute in any way to the delivery of pipeline services are removed from the capital base.[98] The redundant asset can be added back to the RAB if it later contributes to the delivery of pipeline services.[99] In the medium to long term, there is a reasonable expectation that gas networks may become increasingly under-utilised as a whole, but their assets may not necessarily become redundant on an individual basis.

We are aware of one instance where capital redundancy provisions were used to reduce the value of a regulated asset base. In 2005, the Independent Pricing and Regulatory Tribunal of NSW (IPART) declared that part of the Wilton to Wollongong pipeline was redundant due to decreased utilisation. IPART removed the asset from the capital base under section 8.27 of the *National Third Party Access Code for Natural Gas Pipeline Systems*.[100] The service provider sought to have that part of the pipeline rolled back into the capital base in the 2010 access arrangement review. The AER rejected the proposal on the grounds that the redundant asset was not contributing to the delivery of pipeline services.[101]

95 NGR, rule 85.

96 NGR, rule 85(3).

97 NGR, rule 85(4).

98 NGR, rule 85(1).

99 NGR, rule 86(1)

100 IPART*, Revised access arrangement for AGL Gas Networks, Final Decision*, April 2005, pp. 36-41, 78-89.

101 AER, *Jemena Gas Networks, Access arrangement proposals for the NSW gas networks, Final Decision (public),* June 2010, pp. 45-46.

Pros of using capital redundancy provisions:

A cost-sharing mechanism for potentially stranded assets can reduce stranded asset risk by providing certainty to the cost recovery of those assets, even though it may be a partial cost recovery. By agreeing on how to share some stranded asset costs explicitly and upfront, it removes some uncertainty of cost recovery and allows gas access prices to be more predictable in the future, thus promoting efficient use of the gas networks.

A cost-sharing mechanism can be more flexible in dealing with the costs associated with a decline in gas demand, compared to regulatory depreciation that is subject to specific criteria and the regulator’s assessment.

The design of a cost-sharing mechanism is likely to involve a more consultative and transparent engagement between the regulated businesses and their users in determining what may be reasonable and fair in the circumstances for the parties. Consumers would have a stronger voice in the determination of the possible future gas access price paths.

Cons using capital redundancy provisions:

One limitation of the capital redundancy provisions is that an asset may first need to become materially under-utilised or obsolete in order to be declared redundant and be removed from the RAB. However, this may not occur until much later in the distant future when demand for gas falls. The capital redundancy provisions may also only be appropriate to address specific under-utilised assets, rather than network-wide under-utilisation.

By agreeing to a cost-sharing mechanism under the capital redundancy provisions, a regulated business may have to forgo the opportunity to recover some costs from customers. There is presumably a financial disincentive for regulated businesses to propose a cost-sharing mechanism.

This option also involves substantial delay in implementation because a cost-sharing mechanism must be established in the access arrangement first before being applied in a subsequent access arrangement period.[102] This is not ideal, especially when there is a benefit to act early to maximise the potential to eliminate or reduce stranded asset risk through other means (i.e. by adjusting regulatory depreciation).

4.6 Option 5: Revaluation of asset base

Historically, economic regulatory frameworks in Australia have provided a high degree of assurance to regulated businesses that they will be able to recover prudently incurred costs. However, it may not be desirable, or even feasible, to maintain this level of assurance in the future when gas demand is constrained by decarbonisation policies or competing energy sources. It may be necessary to change the current regulatory framework to reflect the material change in circumstances, unforeseen at the time when the framework was designed.

Rather than changing network prices in response to changes in demand, which may create a destructive price spiral, it may make sense to reflect changing demand conditions in the regulatory asset base in the form of periodic revaluation. For example, if at a certain point in time it is forecast

102 NGR, rule 85(2).

that future demand is lower than expected, the regulatory asset base would be revised downwards. Conversely, if demand conditions are forecast to be better than expected, the regulatory asset base would be revised upwards. The downwards revaluation of the asset base can be viewed as the removal from the asset base of partially or fully 'stranded assets'. Careful adjustments in this way would allow the network charges to be kept broadly stable despite the uncertainty in demand.

Revaluations of this kind would expose the network business to a new risk. Compensation would need to be provided for bearing this risk, so that the regulated business can expect to earn (on average) a normal return commensurate with the regulatory and commercial risks it faces.

Pros of revaluing asset base:

If carried out carefully, this approach would place the risk of demand changes on the network businesses, while retaining stable prices for customers. This maintains the confidence of customers in the regulatory framework and therefore preserves their incentive to invest in gas appliances.[103]

Cons of revaluing asset base:

This option would likely require a fundamental, legislative change to the NGL and NGR to allow for partial, periodic revaluation of the asset base and a new "building block" component to compensate for the regulatory risk of RAB revaluations.

It is challenging to estimate the probability of future changes in demand for a gas network and therefore the actuarially fair compensation for the regulatory risk of RAB revaluations and the value of the RAB. There can be material windfall gains or losses if the forecasts of future demand are inaccurate. How we revalue asset bases and how we estimate the compensation for the revaluation risk would likely be a contentious and challenging issue in access price reviews.

Revaluing RABs based on forecast demand volumes may mean that future prices are decoupled from the costs incurred for the purpose of providing network services. . The potential consequence is that a regulated business may not be able to recover all its incurred costs and therefore not be incentivised to make new investments.

The risk of asset write-down or revaluation may increase the low financing costs for network investments, which are predicated on the current regulatory framework that provides the regulated business with a reasonable opportunity to recover its efficient costs. [104] The higher non-systematic risk may increase debt costs and discourage investments that would otherwise be efficient. By potentially denying this opportunity to recover efficient costs, RAB revaluations increase investment uncertainty for the regulated business and the risk compensation that the business may demand. This may increase the long-term cost of network services to consumers and generate higher, rather than lower, network tariffs.

[103] Preserving customers' incentives to invest in gas appliances promotes efficient growth in the gas market and efficient investment and use of the gas networks. This is encouraged under the current national gas regulatory framework. As discussed in section 6.1, this may be perceived as contradictory with decarbonisation policy objectives.

[104] Garth Crawford, Energy Networks Association, *Written-down value? Assessing proposals for electricity network write-downs*, August 2014.

4.7 Option 6: Introducing exit fees

Levying exit fees on customers who disconnect from the gas network can reduce the amount of unrecovered costs associated with their connections remaining in the RAB, thereby reducing the potential for price rises that remaining gas customers would face. Exit fees should be calculated as the difference between the incremental revenue that the customer was expected to contribute at the time of investment and the actual incremental revenue that the customer paid during the time the customer was connected to the gas network. They are distinct from disconnection fees or connection abolishment fees that cover the costs of disconnecting a customer from gas supply services or physically removing the gas infrastructure from the customer's property.

Pros of introducing exit fees:

Levying exit fees across the entire customer base can promote equity among customers by requiring those who leave the gas network to pay a contribution to make up for the costs associated with their use of gas network services, rather than shifting the costs to future gas customers.

Cons of introducing exit fees:

We are not aware of any regulated business who imposes a contractual obligation on customers to pay exit fees. If exit fees are introduced as part of the terms and conditions for new connections, the impact of this measure will be limited to a set of identifiable new customers.

Imposing exit fees makes it harder for customers to switch to alternative fuel sources. This may be considered as anti-competitive and contradictory to governments' decarbonisation policies to curb natural gas use. Also, financially disadvantaged customers may be unable to afford the exit fee, thus being prevented from disconnecting.

There are implementation challenges in managing customers who relocate or disconnect for short periods of time.

Exit fees may be perceived as unfair by gas customers because those who disconnected before the introduction of exit fees did not have to pay. The threat of introducing exit fees may also drive more customers to leave the network earlier than they otherwise would, because they would be incentivised to disconnect from gas to avoid paying exit fees.

Imposing exit fees may not provide clear price signals that consumers need at the time of investment to properly consider the total costs of connecting to gas.

It also seems administratively burdensome to calculate the fair amount of exit fees for each customer with reference to the incremental revenue and costs they have individually contributed to the network.

4.8 Option 7: Increasing fixed charges

Gas access prices are generally structured into fixed charges and volumetric charges that vary based on the volume of gas consumers use. The costs of network investments are expected to be recovered through both fixed charges and volumetric charges over an assumed period. If gas consumers replace their gas appliances with more efficient ones, or only switch some but not all their gas appliances to electricity appliances, they would pay less in variable charges. As such, regulated businesses may under-recover the cost of their investments over the assumed period (stranded asset risk).

A price structure where the fixed costs of supply would be recovered more though fixed charges rather than variable charges may ensure gas users pay for the costs of their gas services, no more and no less, irrespective of how much gas they consume. This may help reduce stranded asset risk contributed by declining gas consumption of individual users.

Pros of increasing fixed charges:

Fixed charges can apply across the customer base rather than an identifiable subset of customers, which may be considered to be more equitable.

Cons of increasing fixed charges:

This application is quite limited in addressing stranded asset risk because it is reliant on little or no decline in the number of customers served.

Increasing fixed charges may encourage customers to disconnect from gas supply completely in some cases. If a customer's gas consumption is low, such as with the use of one gas appliance only, higher fixed charges may make it harder for the customer to manage gas bills by adjusting consumption. This would make it more attractive for the customer to switch to electricity completely, whereby the customer would only incur a marginal cost increase in electricity bill but receive relatively higher savings in avoided gas expenditure.

While the revenue from low-use customers under the current volumetric price structure may be low, but because the incremental cost of supplying gas to them is also low, they nonetheless would be contributing to the network's fixed costs.

Increasing fixed charges may have a greater impact on vulnerable or low-income families who may have less gas consumption, compared to other customers.

4.9 Option 8: Maintaining status quo

The need to take action depends on how one perceives the materiality of the stranded asset risk and the opportunity costs of not taking action. If stranded asset risk is not demonstrated to be material, it may not necessitate any regulatory action. If a proposed action to address stranded asset risk is contrary to consumers' long-term interests, we may not accept it either.

Based on economic regulators' experiences abroad, it is generally recognised that once a non-immaterial stranded asset risk arises, there is a need to adjust regulatory approaches to safeguard consumers' long-term interests. To the extent that stranded asset risk is demonstrated to be sufficiently material, we consider some regulatory action to address the risk will be necessary at the time when investment is being considered. Otherwise, efficient investments may be dissuaded or delayed until such point the regulatory settings address the stranded asset risk, which may not be in the long-term interests of gas consumers.

Pros of maintaining status quo:

Current consumers do not need to pay more to address the potential problems of declining gas demand that may arise in future.

The unintended consequences of ‘getting it wrong’ due to the uncertainty around gas forecasts and likely regulatory changes associated with emissions reduction are avoided.

Cons of maintaining status quo:

Ignoring stranded asset risk may result in a lack of efficient investments in the network to ensure a safe, reliable and affordable gas supply for consumers in the future. A commitment to review regulatory depreciation or risk compensation in the future may not provide regulated businesses with sufficient confidence to undertake irreversible investments now.

Our ability to adjust prices as a means to reduce price uncertainty and stranded asset risk will diminish over time and there is a window of opportunity, ie. a period of time, within which we can make decisions that will produce a desired outcome.[105]

Not permitting asset life adjustments would risk increasing the materiality of any potential future adjustment to asset lives, if stranded asset risk becomes more likely. In other words, there is an opportunity cost of not doing anything to mitigate the risk, particularly when the ability to smooth prices across multiple access arrangement periods and adjust cost allocation among current and future customers are limited by how much time we have before 2050.

Issues for consideration

1) *Is there sufficient uncertainty in future gas demand, or reasonable grounds, that give rise to a non-immaterial stranded asset risk and warrant some regulatory action?*
2) *Which option(s) may be preferable in the specific circumstances of the regulated business to manage demand uncertainty and stranded asset risk? What are the likely immediate and long-term price impacts of the business’s proposed risk-management measures and are they proportional to the identified risks?*

4.10 How other regulators deal with declines in regulated service demand and stranded asset risk

We examine the regulatory approaches economic regulators have adopted in other jurisdictions as they regulate natural monopolies in the face of potential significant decline in demand that would give rise to economic stranding risk.

Example 1	
Jurisdiction	New Zealand
Regulated business(es)	Electricity distribution businesses (EDBs)
Relevant regulator	New Zealand Commerce Commission (NZCC)
Decision	Input methodologies review decision 2016[106]

105 See Schmalensee, R, *An Expository Note on Depreciation and Profitability under Rate-of-Return Regulation*, Journal of Regulatory Economics, 1(3), 1989, pp. 293-298; Crew, M and Kleindorfer, P, *Economic Depreciation and the Regulated Firm under Competition and Technological Change*, Journal of Regulatory Economics, 4(1), 1992, pp. 51-61.

106 NZCC, *Input methodologies review decisions, Topic paper 3: The future impact of emerging technologies in the energy sector*, December 2016, pp.32-33.

What causes economic stranding of assets?	Increasing deployment of emerging technologies, including distributed generation and distributed electricity storage
How does the regulator address stranded asset risk?	The NZCC acknowledged there was a high degree of uncertainty about the potential for asset stranding. It considered it appropriate to take action to address the stranded asset risk in the following way:[107] • allowing EDBs to apply for a discretionary net present value neutral shortening of remaining asset lives, but the adjustment will be capped at a 15% reduction in remaining average asset lives as compared to the situation at the time of the default price-quality path reset • EDBs may elect new asset lives based on their assets' expected economic asset lives rather than their technical asset lives. NZCC considered that its approach does not entirely mitigate stranded asset risks for EDBs, but expands EDBs' ability to mitigate the risk of economic network stranding. The NZCC has thus far not provided any EDBs with a shortening of asset lives upon application.

Example 2	
Jurisdiction	New Zealand
Regulated business(es)	Fibre fixed line access service providers
Relevant regulator	New Zealand Commerce Commission (NZCC)
Decision	Fibre input methodologies decision 2020[108]
What causes economic stranding of assets?	Prospect of competition from lower cost alternative technologies (eg. mobile)
How does the regulator address stranded asset risk?	The NZCC include several measures in the input methodologies to address stranded asset risk by allowing regulated businesses to:[109] • retain some stranded assets in the RAB (in situation where some customers are lost to competitors, but sufficient customers remain to permit all costs to be recovered) • reduce asset lives or provide for an alternative depreciation path • receive a small ex-ante allowance of 10 basis point in cash flows (to compensate for the residual stranding risk not mitigated by the two measures above).

Example 3	
Jurisdiction	England
Regulated business(es)	Gas distribution and transmission network service providers
Relevant regulator	Office of Gas and Electricity Markets (Ofgem)

107 NZCC, *Input methodologies review decisions, Topic paper 3: The future impact of emerging technologies in the energy sector*, December 2016, p. 36.

108 NZCC, *Fibre input methodologies: Main final decision – reasons paper*, October 2020, accessed via https://comcom.govt.nz/__data/assets/pdf_file/0022/226507/Fibre-Input-Methodologies-Main-final-decisions-reasons-paper-13-October-2020.pdf

109 NZCC, *Fibre input methodologies: Main final decision – reasons paper*, October 2020, [6.1022] and [6.1235].

Decision	RIIO-2 Network price controls 2021-2028 - Final Determinations [110]
What causes economic stranding of assets?	Forecast declining demand, energy transition to net zero emissions
How does the regulator address stranded asset risk?	Ofgem applies a front-loaded depreciation profile for post-2002 assets, using a 45 year sum of digits approach.[111] The rate of depreciation is set so that different generations of consumers pay network charges broadly in proportion to the value of network services they receive. [112]

Example 4	
Jurisdiction	The Netherlands
Regulated business(es)	Gasunie Transport Services (GTS), the national gas network operator in the Netherlands
Relevant regulator	Authority for Consumers and Markets (ACM)
Decision	Tariff decision for GTS for 2022[113]
What causes economic stranding of assets?	Forecast declining demand, energy transition to net zero emissions
How does the regulator address stranded asset risk?	ACM allowed GTS to charge network customers earlier by applying declining balance depreciation (diminishing balance depreciation).[114] ACM has moved from targeting a real rate of return to a nominal rate of return (i.e. removing indexation of the regulatory asset base) so that the inflation compensation for a given year is charged to gas network users, rather than to future users.[115] ACM also allowed divestments from the RAB to be written off entirely in the year that the divestment occurs, distributing such costs to current rather than future users.[116]

Example 5	
Jurisdiction	Australia
Regulated business(es)	DBNGP (WA) Transmission Pty Ltd (DBP)
Relevant regulator	Economic Regulation Authority Western Australia (ERA)

110 See, Ofgem, *RIIO-2 Final Determinations – Finance Annex (Revised), February 2021, pp.112-113 and Ofgem, RIIO-GD1: Final Proposals – Overview, Final Decision*, 17 December 2012, pp.35-36.

111 Sum-of-years' Digits depreciation results in a more accelerated depreciation than straight line. It is calculated by first adding each year's digits, over the depreciation period. So for instance, with a depreciation of 5 years, this would be 1+2+3+4+5=15. Next, the depreciation for each year is calculated by dividing the asset's number of useful years left (in year 2 for instance, this would be 4), by the sum-of years' digits (15). This figure is then multiplied by the Gross Book Value of the asset to give the depreciation for that year.

112 Ofgem, *RIIO-GD1: Final Proposals - Finance and uncertainty supporting document Finance and uncertainty supporting document*, 17 December 2012, pp.6-7.

113 See https://www.acm.nl/nl/publicaties/tarievenbesluit-gts-2022

114 Authority for Consumers and Markets, *Methodebesluit GTS 2022-2026*, May 2021, pp. 45-46. Accessed via https://www.acm.nl/sites/default/files/documents/2020-08/ontwerpmethodebesluit-gts-2022-2026.pdf

115 Ibid, pp. 43-44.

116 Ibid, pp. 48-49.

Decision	Final decision on proposed revisions to the Dampier to Bunbury Natural Gas Pipeline access arrangement 2021-25[117]
What causes economic stranding of assets?	Competition via alternative energy sources in the future
How does the regulator address stranded asset risk?	The ERA accepted DBP's proposal to cap the economic life of its pipeline to 2063 and adjusted DBP's regulatory depreciation schedules accordingly.[118] The ERA recognised that DBP faces a greater likelihood that the Dampier to Bunbury Natural Gas Pipeline's economic life will be shorter than its technical life due to the combination of technological change and environmental policies curtailing natural gas use.

4.11 Should governments or taxpayers pay for stranded assets?

The fact that there is a policy as well as economic dimension to the expected decline in gas demand raises the question of whether the stranded asset risk should be allocated only between regulated businesses and consumers.

In its access arrangement engagement process, Evoenergy conducted a consumer workshop on stranded assets.[119] There was a strong opinion expressed by a number of participants that the costs of reduced asset lives should not be borne by customers at all.[120] Some considered that government and taxpayers should pay for stranded asset costs, noting that the proposal to reduce asset lives was a consequence of government policy to eliminate gas usage. However, it is important to note that the fall in gas demand is not solely driven by government policies but also technological and social changes that are motivated by climate change concerns.

The national gas regulatory framework does not provide for the AER to allocate stranded asset risk or the costs of gas infrastructure to governments or taxpayers. Should a government provide financial support to address stranded asset risk in gas networks, this will likely be factored in the AER's decisions in determining access prices. For example, the need for accelerated depreciation or ex ante compensation may be reduced if a government's financial support or commitment has substantially reduced the stranded asset risk.

There are examples where State and the Commonwealth Governments have borne costs associated with changes in government policy. In 2014 the South Australian Government restricted fishing in marine park sanctuary zones. The Government bought commercial fishers' licences or catch entitlements equivalent to the estimated reduction in commercial catch/effort brought about by the implementation of the sanctuary zones.[121]

In managing the Murray Darling Basin, the Commonwealth Government implemented water rights and set sustainable diversion limits. The Commonwealth Government undertook water buybacks to account for the difference between the pre-implementation diversion limits and the sustainable

[117] ERA, *Final decision on proposed revisions to the Dampier to Bunbury Natural Gas Pipeline access arrangement 2021-2025*, April 2021.

[118] Under its former access arrangement, DBNGP's pipeline assets were deemed to have a 70-year life. See ERA, *Final decision on proposed revisions to the Dampier to Bunbury Natural Gas Pipeline access arrangement 2021-2025*, April 2021, Table 173, p.359.

[119] Evoenergy, *2021-26 Access Arrangement proposal, Attachment 4.1 Stranded asset risk deep dive workshop outcomes report*, January 2021, p.7.

[120] Ibid, pp. 7-9.

[121] Government of South Australia, *Productivity Commission Inquiry – Regulation of Australian Marine Fisheries and Aquaculture Sectors, Submission from the Government of South Australia*, May 2016, p.15. Accessed via: https://www.pc.gov.au/__data/assets/pdf_file/0005/200957/sub063-fisheries-aquaculture.pdf

diversion limits set post-implementation. This was to reduce the impact on individual water entitlement holders of the reduction in diversion limits.[122]

In both these instances the government acquired the property rights. Were hydrogen to become a feasible future option, and if the government were to acquire property rights in relation to gas assets on behalf of consumers, it may be possible for the government to realise a return on and of that property right.

4.12 AER's preliminary view and considerations

Adjusting regulatory depreciation is the most accessible regulatory tool we currently have in managing demand uncertainty and influencing the trajectory of future gas access prices, notwithstanding that there are other options available.

Our preliminary view is that some form of accelerated depreciation would be appropriate if there is sufficient evidence to demonstrate and quantify the pricing risk and stranded asset risk arising from demand uncertainty. We can respond to the forecast change in demand in a pragmatic manner and adjust the tariffs over time to facilitate an equitable and efficient allocation of costs between current and future gas customers.

Importantly, adjusting depreciation offers us the greatest flexibility in responding to new information in the future if the natural gas substitution pathways or actual demand turn out to be different than expected. Unlike other options under consideration, accelerating depreciation does not lock in a price change permanently, which avoids providing a material windfall gain or loss to either the regulated businesses or consumers if actual gas demand differs markedly from our assumption made under uncertainty. Depreciation can be adjusted in later access arrangement periods when the future of gas networks utilisation becomes clearer. Also, the price impact of accelerated depreciation is more equitably spread among all gas customers of the network and is not confined to a specific sub-group.

Since regulatory depreciation is determined by the length of the expected economic life of assets, the longer the time we have to make adjustments, the smoother the depreciation profile/ price impact would be. The opportunity and flexibility for adjustment is greatest when we act as soon as we can to minimise the adverse impact of a decline in gas demand.

[122] Murray–Darling Basin Authority, *Guide to the proposed Basin Plan*: Volume 1, 2010, pp.xii,48, 152-153. Accessed via: https://www.mdba.gov.au/sites/default/files/archived/guide_pbp/Guide_to_the_Basin_Plan_Volume_1_web.pdf ; Murray–Darling Basin Authority, *Guide to the proposed Basin Plan*: Volume 2, 2010, p.237. Accessed via: https://www.mdba.gov.au/sites/default/files/archived/guide_pbp/Guide-to-proposed-BP-vol2-04.pdf

AER's expectation:

To demonstrate stranded asset risk, we expect regulated businesses to provide plausible future energy scenarios that covers a spectrum of outlooks from the most pessimistic to the most optimistic for their networks, and to estimate the likelihood (probability) of each scenario. We expect regulated businesses to demonstrate the magnitude of stranded asset risk and possible divestment and investment plans under each scenario. In particular, to demonstrate the materiality of stranded asset risk and the justification for early regulatory intervention, we expect a regulated business to provide compelling evidence to identify:

- the factors that influence the estimates of expected economic lives, such as applicable government policies, evidence of their customers' sentiments in switching away from gas, developments in competing technology etc
- those assets that may be repurposed for transporting hydrogen and those that cannot be
- those assets whose economic lives may need to be adjusted to reflect the potential decline in long-term demand
- the value of stranded assets under the different forecasting scenarios
- the costs that may be avoided or incurred in the different forecasting scenarios
- the level of customer support for the business's proposed action to manage the risk and the quality of that customer engagement
- analysis of the price impact for the business's proposed action.

In line with the economic principle of allocation of risk, we consider that regulated businesses are best placed to manage the risk of cost recovery from lower uptake in the near term (driven by increases in regulatory depreciation) versus asset stranding risks in the longer term. We recognised that a broad base approach may not necessarily be in the long-term interests of consumers as gas networks face varying levels of asset stranding and operate in different environments. As such, we would assess the depreciation path proposed by regulated businesses on a case-by-case basis, with reference to the evidence submitted by the businesses.

Regulatory depreciation can be adjusted by shortening the period over which assets are depreciated or changing the rate at which assets are depreciated over time.

4.12.1 Adjust the expected economic lives for assets

Generally, we require a regulated business to depreciate its assets on a straight-line basis over the 'standard asset lives' nominated for each high-level asset class used by the business. Standard asset lives are based on the period in which the assets are expected to last technically (technical life).

Instead of using standard asset lives (or remaining lives), we may specify shorter asset lives for assets that are subject to stranding risk to reflect the period in which they would likely be in economic use, consistent with the principle of providing adequately for cost recovery. This would require the regulated business to demonstrate that there is a material risk of economic stranding for the relevant assets and when that may likely occur. If we adjust the economic lives of all assets that are subject to stranding risk in the RAB, it will likely result in significant price increases or volatility. Therefore, considering the price elasticity of demand, a targeted approach may achieve a better outcome for long-term consumers depending on the circumstances.

We have adopted this approach for new pipeline assets in the decision for Evoenergy 2021-26 access arrangement, given the ACT Government's commitment to phase out fossil-fuel gas in the ACT. We considered this a prudent, responsible and precautionary first step to protect the long-term interests of Evoenergy's gas consumers from asset stranding risk.[123]

AER's expectation:

We would expect regulated businesses to provide compelling evidence to justify the asset lives that they have proposed.

Notwithstanding the 2050 net zero emissions targets adopted by State and Territory governments, this does not necessarily mean the gas networks must be decommissioned or retired completely at that time. There is a possibility that hydrogen or bio-methane can be used as reticulated gas in the future. There is also a possibility that natural gas may continue to be used by specific customers (for example, industrial users who must use natural gas as a chemical feedstock), such that gas networks may continue to operate beyond 2050 at a smaller scale or in specific regions. Therefore, in our view, assuming 2050 as the cap for the expected economic lives of pipeline assets without reasonable evidence or analysis would be inappropriate.

As regulated businesses may face different levels of stranded asset risk, we may consider a departure from our typical approach of assuming uniform standard asset life for a specific class of assets (based on technical life). We may allow the same class of assets to have different assumed asset lives (depending on the economic stranding risk the relevant business faces) among regulated businesses.

4.12.2 Adjust the depreciation profile

We have traditionally adopted a straight-line depreciation approach, whereby the value of the asset is depreciated in equal amounts in real terms over time. To enable different generations of consumers to pay network charges broadly in proportion to the value of network services they receive, it may be better to front-load depreciation such that a higher portion of costs can be recovered earlier in time, when there are more customers in the market to share the costs. This may mean a different depreciation method, such as a diminishing balance method[124] or a tilted annuity depreciation method[125], is more fit-for-purpose than a straight-line method.

[123] AER, *Draft decision Evoenergy 2021-26 access arrangement*, 27 November 2020, pp. 10, 40.

[124] Under the diminishing balance method of depreciation, a decreasing charge over the useful life is applied, resulting in the largest depreciation expense in the first year through to the smallest depreciation expense in the last year. The depreciation expense is calculated by applying the depreciation rate to the carrying value of the asset rather than the initial asset book value. (AASB 116/ IAS 16).

[125] Tilted annuity depreciation is a proxy for economic depreciation, where the written down value of an asset at any point in time is equal to the NPV of the expected future cash flows generated by the asset. A tilted annuity calculates an annuity charge that changes between years at the same rate as the price of the asset is expected to change. This results in declining annualisation charges if prices are expected to fall over time. The tilted annuity charge is calculated as: {(r-p)/(1-((1+p)/(1+r))^t)}xI, where r = cost of capital, p = rate of price change ("tilt"), t = asset lifetime, I = investment. This depreciation method is commonly used in telecommunication access pricing regulation to take into account the competitive dynamics of the sector or the decreasing input prices due to technological progress. It is often referred to as competitive depreciation.

Another way to adjust depreciation was suggested by DBNGP (WA) Transmission Pty Ltd (DBP) in its 2021-25 access arrangement proposal. DBP relied on the theoretical Window Of Opportunity Past (WOOPS) framework originally employed by Crew and Kleindofer (1992) to quantify the necessary depreciation adjustment or to estimate an end date for the Dampier Bunbury Pipeline's economic life such that:[126]

> …given the competitive environment which is forecast to exist in the future due to technological change, the regulatory pricing schedule up to the point that this competitive market emerges is capable, when combined with revenues expected to be earned in the competitive market, to deliver sufficient returns to meet the efficient costs of the relevant investment.

Front-loading depreciation and shortening asset lives can together have a significant impact on prices. To adjust the regulatory depreciation in a broad way would potentially distort replacement and consumption incentives in both the short and long run. As such, we would require such proposals to be well-justified and strongly supported by consumers.

To depart from our typical straight-line depreciation approach may also require fundamental changes to the revenue model which would be subject to consultation requirements under the NGR.[127] As such, a front-loaded depreciation profile may not be applicable in upcoming access arrangement reviews for the Victorian gas transmission and distribution businesses in 2022.

AER's expectation:

Regulated businesses, consumers and regulators may have differing perspectives on how quickly network investments can or should be depreciated. Consumer views are vital in determining what depreciation adjustments would be in the long-term interests of consumers under the circumstances. Consumer views are also important to us in understanding their expectations of future energy needs and the particular challenges that captive customers may face in this energy transition. Such information will enable us to determine what regulatory approaches would be efficient and prudent.

We expect that, in proposing any variation to the existing depreciation schedules, regulated businesses would actively and meaningfully engage with their customers on the range of available options and reflect customers' feedback in their proposals. We consider that good consultation will involve a range of scenarios being put to consumers with respect to demand forecasts, expenditure and any stranding mitigation measures, together with the price impacts of those scenarios.

[126] DBNGP (WA) Transmission Pty Ltd, *Five year plan for the Dampier to Bunbury Natural Gas Pipeline, 2021-2025 Final Plan, Attachment 9.2, Assessment of the Economic Life of the DBNGP*, January 2020. See Crew, M and Kleindorfer, P, *Economic Depreciation and the Regulated Firm under Competition and Technological Change*, Journal of Regulatory Economics, 4(1), 1992, pp. 51-61.

[127] NGR, r. 75A.

Issues for consideration

3) *Are the expected economic lives for the specific assets proposed by the regulated business supported by evidence and best available information? Is it relevant to consider the probability that the assets may be repurposed to carry other gases in the estimation of the expected economic lives for the assets?*
4) *Is the depreciation adjustment proposed by the regulated business reasonable or equitable in the current circumstances, having regard to both its interest to recover efficient costs and consumers' interests in not having to pay more than necessary for gas network services?*
5) *Does the current NGL revenue and pricing principle that a regulated business should have a reasonable opportunity to recover efficient costs extend to making adjustments to regulated prices to ensure the business is able to recover the sunk costs of all its investment in the current circumstances?*
6) *When considering the extent to which regulated prices should be adjusted to address a stranded asset risk, should there be a distinction drawn between policy changes and technological and competition changes that underpin the stranded asset risk?*
7) *Should there be a specific limit on the increase in regulatory depreciation across all regulated networks and across periods to provide more certainty in regulatory decisions and price paths? For instance, the limit could be defined by a reduction in standard asset lives or maximum cap on revenue impact. If yes, how should the limit be set?*

5 Other potential changes to our access arrangement reviews

The option analysis in section 4 focuses primarily on how to distribute costs of network investments efficiently and equitably to consumers. However, how we ensure adequate cost recovery of investments is only part of the equation in managing uncertainty in future gas demand.

We must also consider how we evaluate the prudency and efficiency of new investments going forward. With declining gas demand, there is a risk of over-estimating costs and capacity needs of gas networks. To minimise unnecessary new costs incurred by regulated businesses and therefore the cost burden of future gas customers, we may need to adopt more stringent or conservative assumptions in our expenditure assessments and demand forecasts, and adjust the incentives currently provided under the regulatory framework.

In this section, we examine other aspects of our regulatory approach in access arrangement reviews that may need to change in response to the uncertainty of future gas demand and climate change policy development. We cover the need for potential changes to the

- way we undertake expenditure assessments (section 5.1)
- demand forecasting approaches used (section 5.2)
- operation of financial incentives schemes (section 5.3)
- form of regulation – price versus revenue caps (section 5.4)
- mechanisms used to manage uncertainty (section 5.5).

5.1 Expenditure assessments

Naturally, with the expectation of shorter economic lives for pipeline assets, the incremental revenue expected to be derived from a capital investment would be much more constrained. The expected economic lives of assets are crucial in determining the prudency and efficiency of investments in an environment of uncertainty. For example, in light of the energy transition in the United Kingdom, Ofgem adopted a cost-benefit analysis cut-off date of 2037 for asset management mains investments by regulated gas distribution businesses to protect customers against the risk of assets becoming stranded.[128]

Rule 79(1) of the NGR stipulates that conforming capital expenditure is capital expenditure that satisfies 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

[128] Ofgem, *RIIO-2 Final Determinations – GD Sector Annex (Revised)*, February 2021, pp. 112-113, [3.141].

(c) the capital expenditure must be for expenditure that is properly allocated in accordance with the requirements of subrule (6).

Rule 79(2) provides 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).

The consideration of uncertain demand and expected economic lives of assets would be relevant in net present value analysis and economic value analysis under rules 79(2)(a) and (b) respectively. Also, if prevailing tariffs are used to forecast incremental revenue and we bring forward depreciation or provide compensation for stranded asset risk that may result in higher tariffs. We must consider whether there is a risk of over-estimating incremental revenue subject to the assumptions of future prices and demand.

Some capital expenditure may be justifiable under rule 79(2)(c), even if it does not satisfy the criteria under rules 79(2)(a) and (b). This calls for a careful consideration of whether investments in long-lived assets are efficient and prudent to achieve the objectives under rule 79(2)(c), given the uncertainty in the future utilisation of the assets.

Natural gas demand is likely to persist for some time despite the risk of a decline in the future sometime away. It is important to ensure a prudent level of expenditure on network investment or maintenance to maintain safe and reliable gas services for remaining customers, notwithstanding the risk that these expenditures may have economic lives shorter than expected or may not produce a net benefit ultimately.

AER's expectation:

We expect regulated businesses to apply consistent assumptions across all the building blocks of the access arrangement proposal where possible. This includes their demand forecasts, their expected economic lives of their assets, and their economic value and net present value analyses of their expenditure proposals.

5.1.1 Market expansion capex

In the absence of any prohibition on new gas connections, we must assess what levels of market expansion capex[129] are reasonable. New connection growth may not be in the long-term interests of consumers in a potentially declining reticulated gas sector, if they add to the cost burden of future gas consumers.

Although investing to connect new customers may benefit the wider consumer base with increased customer numbers to share fixed costs, this could also add to the value of assets that may be stranded in future. Further, the increase in demand could also lead to the need for network augmentation to increase network capacity to service demand, which may not be justifiable in an environment of demand uncertainty or long-term decline in demand.

In general, the AER approves a network business's capital expenditure to connect new customers to its network if it is demonstrated that the incremental revenue to be recovered from the new customers over a certain period will outweigh the incremental costs (i.e. it is net present value positive). To the extent that the cost of the connection outweighs the expected revenue associated with that connection, a capital contribution is charged to the new customer.[130] The net connection costs[131] will then be added to the RAB of the network business and recovered from the whole customer base through network tariffs.

The cost recovery time period considered in such capital expenditure assessments is typically the technical life of the pipeline assets, assuming the new customers would continue to use the gas network services until the retirement of the assets. If customers leave the gas network before they have contributed sufficient incremental revenue over the period as first assumed when the investments were made, then the remaining customers in the network will share the outstanding incremental costs caused by the new connections.

We consider that all new market expansion capital expenditure proposals should take into account stranded asset risk if it is non-immaterial. The cost recovery time period assumed in the net present value analysis or incremental revenue assessment could be shorter than previously assumed and should reflect a possibility that not all new connecting customers would remain in the gas network within the period with reference to best available demand forecast. This in turn would likely result in higher capital contributions required from new connecting customers to justify a market expansion capital expenditure as conforming capital expenditure under rule 79 of the NGR.

High capital contributions may discourage new connections from proceeding including those that may be deemed efficient in some circumstances. This problem may be exacerbated where it is the property developer who decides whether to connect to gas based on costs, rather than the end customers who may choose to connect to gas notwithstanding the upfront costs. In addition, high capital contributions may also deter financially disadvantaged customers from connecting to gas.

[129] Market expansion capex refers to capex incurred to expand the network to connect new customers to the gas network. This is in contrast with augmentation capex, which is incurred to increase the network capacity to accommodate higher volume demand with the existing connections of the network.

[130] Rule 82(1) of the NGR provides that a user may make a capital contribution towards a service provider's capital expenditure.

[131] Net connections expenditure is equal to the total connections expenditure less capital contributions.

5.1.2 Operating expenditure/capital expenditure substitution

The uncertainty in demand may also affect a regulated business's decision to substitute capital expenditure (capex) with operating expenditure (opex) to cope with stranded asset risk. Unlike capex, opex is generally recovered from customers in the access arrangement period it is incurred.

Rule 91(1) of the NGR requires that opex 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 delivering pipeline services.

Where there is material uncertainty about the future utilisation of gas networks, it is conceivable that regulated businesses may consider opex over capex to be prudent investments to achieve the lowest sustainable cost of delivering pipeline services. For example, it may be economic in some cases to maintain assets for longer rather than to replace them, and to recover the expenditure over a shorter period.

5.1.3 Optionality for repurposing gas networks

The possibility that hydrogen may be used as a reticulated gas in the future is highly speculative at this point. To accommodate hydrogen, regulated businesses may need to make modifications to their networks or undertake more expensive capital expenditures to address the needs of current natural gas customers while upgrading the network's technical capability to transport hydrogen.

The economics and technical feasibility of using hydrogen as a reticulated gas are not yet known and there is a risk that investments made for the sole purpose of carrying hydrogen could be stranded. However, to prevent or delay network investments that optimise the potential to carry hydrogen in existing gas networks may foreclose the opportunity of using hydrogen as reticulated gas realistically in the future. We need to consider whether it is in the long-term interests of gas consumers to preserve optionality when evaluating capital investments that are for repurposing gas networks, particularly when future hydrogen users are not considered as gas consumers under the NGL or NGR at this stage.

Issues for consideration

8) *Are the new capital expenditure criteria in rule 79 of the NGR still appropriate to ensure that conforming capex will best achieve the NGO if there is an expectation of material decline in the future demand for gas network services?*

9) *Where there is high uncertainty in future gas demand, is it prudent and efficient for a regulated business to substitute capital expenditure with operating expenditure to avoid stranded asset risks even if it may result in higher costs in the long run? In other words, how much of a risk premium should consumers pay to avoid the risk of having to pay more than expected for gas services in the future?*

10) *To what extent is it in the long-term interests of consumers to fund any network investments that may be predominantly for enhancing a network's capability (or potential) to carry hydrogen or other gases in meeting a net zero emission target in the future?*

5.2 Demand forecast

Demand forecast is an integral part of our expenditure forecasts. With the uncertainty surrounding gas demand, it is likely to be challenging for regulated businesses or the AER to identify prudent expenditure levels based on historical trends.

We have not yet seen any drastic changes or decline in gas demand across eastern Australia. The transition away from natural gas, while inevitable, does not appear to be immediate. The decline in gas demand is likely to occur over the next 30 years, with uncertain speed and magnitude. This uncertainty makes it challenging to rely on past data about costs and capacity to estimate future costs and volumes.

AER's expectation:

We expect that, in preparing their access arrangement proposals, regulated businesses would:

- take into account relevant climate change policies and cross-elasticities of demand for natural gas substitutes in their demand forecasts
- forecast a range of different possible demand scenarios, with associated probabilities
- look well beyond the next regulatory period, and would consider demand and supply conditions potentially several regulatory periods into the future
- form a view on whether or not current price levels will be able to maintained in the future, in the face of different demand scenarios. If there is a prospect that prices will not remain stable, we expect this possibility to be explored with customers (as part of the consumer engagement) and to be explained in the access arrangement proposal, including proposed mechanisms for mitigating the consequences.

5.3 Financial incentive schemes

The efficiency benefit sharing scheme (EBSS) and capital expenditure sharing scheme (CESS) promote efficient expenditure by providing a continuous financial incentive for network businesses to undertake efficient expenditure. Network businesses and customers/consumers share the benefits of any opex and capex underspends. We will need to consider if these incentive schemes remain fit for purpose given the expected decline in gas demand.

For example, where a network business faces strong incentives to minimise customer disconnections and asset stranding risks, we may not need additional financial incentives such as the CESS for a network to undertake efficient capex. The more exposed a network business is to asset stranding risks, the more incentives it may have to minimise capex.

The EBSS is designed to allow network businesses and customers to share efficiency savings in perpetuity. If there is a high likelihood that the gas network has a limited lifespan then the sharing of costs and benefits between regulated businesses and consumers under the EBSS may be different than previously assumed.

5.4 Form of regulation – Price vs. Revenue Cap

Given the uncertainty around future gas demand and the decarbonisation policy objectives, there may be a need to change the form of regulation control or to embed some flexibility into the price control framework to manage risk.

Regulated gas networks are generally subject to price-cap regulation. Under a price cap, regulated businesses cannot set prices higher than the weighted average price cap we determine by dividing their required revenues with forecast demand. Under a revenue cap, regulated businesses cannot set prices higher than what they need to recover their required revenues.

Revenue caps and price caps both promote and reward a business for cost-efficiency in supply of the regulated service. However, the choice between revenue caps and price caps influences the variability and predictability of consumer prices and regulated businesses' revenues. A price cap provides within-period average price stability for consumers but regulated businesses are exposed to the risk of over- or under-recovery of revenue. A revenue cap provides regulated businesses with guaranteed revenue, but may lead to more price volatility for consumers within the price control period. Consumers face higher risk of price volatility between periods under a price cap compared to a revenue cap.

Within an access arrangement period, the cost associated with the difference between actual and forecast demand (demand risk) is allocated to regulated businesses under a price cap, and to consumers under a revenue cap. During periods when expected demand is uncertain, the demand risk is heightened.

Under price-cap regulation, network businesses have an incentive to under-forecast demand or use more conservative estimates of demand, to avoid under-recovering their required revenues during the period. The uncertainty surrounding future gas demand makes it very challenging to forecast demand robustly and accurately. This increases the risk that consumers will pay more than necessary for regulated pipeline services under price-cap regulation if actual demand turns out to be higher than forecast. Conversely, if actual demand is lower than forecast, regulated businesses will bear all the costs associated with the demand risk.

In our final decision for Evoenergy 2021-26 gas access arrangement, we rejected Evoenergy's proposed residential demand forecast and substituted a revised (higher) forecast. Nevertheless, we recognise the significant uncertainty with demand forecasting in Evoenergy's service area and noted that Evoenergy may seek to vary its access arrangement in mid-period if actual demand is substantially different to our demand forecast.[132]

Another effect of price-cap regulation is that it incentivises demand growth and new connections. These incentives are inconsistent with efforts to reduce fossil fuel use and decarbonise the Australian economy (this is further discussed at section 6.1). Revenue cap regulation removes the incentive for regulated businesses to under-forecast demand, but also removes the financial incentive for them to increase connections and gas consumption even when efficient to do so.

Under price-cap regulation, regulated businesses generally design their tariff structures to be declining block tariffs to incentivise customers to use more gas. The price per unit falls as consumption increases. This encourages greater utilisation of gas networks, and minimises bill

[132] AER, *Final Decision Evoenergy Access Arrangement 2021-26, Attachment 12 Demand*, April 2021, p.4.

impacts of higher usage during peak times of the year for customers. Declining block tariffs are also inconsistent with governments' decarbonisation policies. If revenue cap regulation is adopted, the resulting tariff structures would likely be changed from declining block tariffs to one that has less incentives on consumption growth.

Issues for consideration

11) *With respect to the regulated business's circumstances, is it still reasonable to assume that the business can manage demand risk or stimulate gas demand? Is price cap regulation still fit for purpose in the business's circumstances?*
12) *Is it consistent with the NGO to align the incentives under the form of control regulation and tariff structures with decarbonisation policies?*

5.5 Mechanisms to manage uncertainty

We are considering the benefits and costs of introducing mechanisms that manage the uncertainty created by climate change policies and their impact on regulated businesses' revenues.

For example, in the United Kingdom, Ofgem has introduced a 'net zero re-opener' across all energy networks (including gas) to allow for any necessary adjustments to the price control within the RIIO-2[133] regulatory period in response to changes connected to the meeting of the Net Zero targets, subject to a materiality threshold.[134] Ofgem has also introduced a Heat Policy re-opener for gas distribution businesses to vary revenue allowances in response to changes to specific regulations and connection charging methodologies that support the transition to low carbon heat.[135]

If demand forecast risk within an access arrangement period is high (as discussed in section 5.4), it may be beneficial to allocate the risk between regulated businesses and consumers, rather than to one party. This may be achieved by introducing price re-openers to adjust price caps in mid-access arrangement period under price-cap regulation or imposing limits on the yearly change in the required revenues that regulated businesses may recover from customers under revenue cap regulation.

The current regulatory regime allows a regulated gas business to submit a proposal for variation of an applicable access arrangement within an access arrangement period.[136] However, the AER cannot vary or revoke an access arrangement during an access arrangement period unless the determination is affected by a material error or deficiency.[137]

133 RIIO stands for Revenues = Incentives + Innovation + Outputs. RIIO-2 is the exercise through which Ofgem determines the income that the gas and electricity networks will receive over the next price control period. The RIIO-2 process is staged. The final determinations made in February 2021 relates to the 2021-26 period for gas distribution and transmission businesses.

134 Ofgem, *RIIO-2 Final Determinations – Core Document (Revised)*, February 2021, pp. 94-98.

135 Ofgem, *RIIO-2 Final Determinations – GD Sector Annex (Revised)*, February 2021, pp. 149-151.

136 NGR, r. 65.

137 NGR, r. 68. The material error or deficiency must be of one or more of the following kinds: a clerical mistake or an accidental slip or omission; a miscalculation or mis-description; a defect in form; a deficiency resulting from the provision of false or materially misleading information to the AER.

The use of re-openers (with a pre-defined trigger event) may introduce additional complexity to an access arrangement review and significant administrative burden. This may weigh against regulated businesses' ability to submit access arrangement variations at any time.

6 Potential changes required for the national gas regulatory framework

In addition to considering how the uncertainty in future gas demand may affect specific elements of our access arrangement reviews, we observe that there are some limitations of the national gas regulatory framework in adapting to the current energy transition. This may warrant legislative changes to the NGL or NGR.

Potential changes to the NGL or NGR are explored in this section, which looks at:

- conflicting policy objectives between the national gas regulatory framework and decarbonisation policies (section 6.1)
- how changes in the gas sector potentially affect the long-term interests of consumers in the electricity sector (section 6.2)
- whether the regulatory framework is still fit for purpose given the energy transition occurring (section 6.3)
- whether the existing regulatory framework applies to sustainable gases (section 6.4).

6.1 Conflicting policy objectives between the national gas regulatory framework and decarbonisation policies

Decarbonisation policies encourage consumers, particularly residential gas customers, to reduce gas consumption or switch from gas to electricity. However, this appears contradictory to the objectives of the national gas regulatory framework, which encourages more gas consumption to promote efficient utilisation of the gas network and to lower the prices paid by gas consumers. This inconsistency will likely persist as long as natural gas, rather than sustainable gas, is regulated under the national gas regulatory framework.

The AER is required to perform its economic regulatory functions or powers in a manner that 'will or is likely to contribute to the achievement of the national gas objective'.[138] The National Gas Objective (NGO) 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*'.[139]

In its guide 'Applying the Energy Market Objectives', the Australian Energy Market Commission (AEMC) states that the national energy objectives (including the NGO):[140]

> *…do not specifically require the Commission to have regard to the long-term interests of consumers with respect to climate change or the environment. Instead, the national energy objectives direct the Commission to consider the achievement of economic efficiency in the long-term interests of consumers with respect to specified matters, being the price, quality, safety, reliability and security of the supply of energy or energy services. However, in order to make decisions that meet the national*

[138] NGL, s 28(1)(a).

[139] NGL, s 23.

[140] AEMC, *Guide to applying the energy market objectives*, July 2019, pp. 8-9.

> *energy objectives, the Commission considers whether its decisions are robust to any impacts on price, quality, safety, reliability and security of supply of energy or energy services, if these matters are impacted by mitigation or adaptation risk that manifests due to the issue of climate change.*

By the same token, the AER would need to consider whether its decisions are robust to any impacts on the price, quality, safety, reliability and security of gas supply caused by climate change policies or mitigation actions.

The AER may be able to consider decarbonisation policies or objectives if they constitute a regulatory obligation under the national gas regulatory framework. However, it appears difficult to reconcile the inherent tension between decarbonisation objectives and the NGO without explicit guidance in the NGL or NGR on how to address the conflict between the two.

Issues for consideration

13) *Should the national gas regulatory framework be amended to explicitly take into account the benefits and costs of reducing carbon emissions in the provision of natural gas services? If so, how?*

6.2 Consideration of gas and electricity consumers' interests

The national gas regulatory framework applies to pricing and regulation of natural gas networks, and the decision framework instructs the AER to look at the long-term interests of current and future gas consumers. It may be ambiguous whether the AER can consider the implications of its gas regulatory decision on electricity networks or consumers under the NGL/NGR framework, or vice versa.

For instance, the NGO makes reference to the *long-term interests of consumers of natural gas*. Also, rule 79(3) of the NGR, which relates to the economic value assessment for new capital expenditure, requires consideration to be given only to economic value directly accruing to the service provider, gas producers, users and end users.

In the AEMC's guide 'Applying the Energy Market Objectives', the AEMC notes that: [141]

> *Consumers in the context of the energy market objectives are consumers in general, or all consumers, rather than a particular type or group. This includes residential consumers of energy and small businesses, but also large industrial users such as aluminium smelters or LNG plants.*

The AEMC notes that the energy objectives were drafted in this way because it is considered that an institution with delegated powers (such as the AER) should balance the interests of all consumer groups in the market rather than prioritise the interests of one.

We acknowledge that the long-term interests of consumers across the energy market may not always be aligned. In the second reading speech for the *Bill for the Statues Amendment (National Electricity and Gas Laws-Limited Merits Review) Act 2013* (SA), the Commonwealth Minister for Industry and Science noted that:

[141] AEMC, *Guide to applying the energy market objectives*, July 2019, pp. 4-5.

> *"The national electricity objective and national gas objective explicitly target economically efficient outcomes that are in the long-term interests of consumers, but the nature of decisions in the energy sector are such that there may be several possible economically efficient decisions,* ***with different implications for the long-term interests of consumers****"* (emphasis added).

Our view is that the NGL or the NGR as currently drafted do not limit the AER's ability to take into account those differing implications on consumers across the energy sector when making decisions that target economically efficient outcomes.

To the extent that energy service providers are able to, we would encourage them to take into account the implications of their specific proposals on energy consumers, including both gas and electricity consumers where relevant. It is becoming increasingly important that the AER considers the interdependencies between electricity and gas in this energy transition and targets economically efficient outcomes in the energy sector as a whole.

6.3 Is the regulatory framework still fit for purpose in this energy transition?

The national gas regime was developed at a time when the gas market was growing and was expected to continue to expand. The regulatory framework is predicated on the assumption that natural gas service providers can exercise monopoly power if unregulated. The regulatory framework does not appear to contemplate a scenario of curtailment or decline in natural gas demand, or that gas networks may have an end-life. The market has evolved in ways unforeseen when the rules were developed.

6.3.1 Is it still in the long-term interests of consumers to encourage growth in the gas market?

The national gas framework encourages growth in the market of gas pipeline services when it is efficient to do so. For example, one of the depreciation schedule criteria require that access prices (reference tariffs) to be varied, over time, in a way that promotes *efficient growth* in the market for reference services (emphasis added). Price-cap regulation and declining block tariffs are used to encourage growth in the gas market. Also, we generally accept efficient market expansion capital expenditure proposals on the assumption that more new customers mean lower prices for all gas consumers and that most of these customers will stay on the network consistently.

However, given the uncertainty associated with the energy transition in Australia, it may no longer be in gas consumers' interests to allow further growth in the gas networks at this point, which contributes to greater risk of stranded assets, until the economics of using hydrogen or bio-methane as reticulated gas can be proven.

6.3.2 Does the current regulatory framework still promote consumers' interests if gas network services become a sunset industry?

The rules dealing with depreciation in the NGR and the pricing and revenue principles in the NGL may not always promote consumers' interests in a world of declining gas demand. The regulatory framework provides scope for regulated prices to be adjusted to provide regulated businesses with a reasonable opportunity to recover their incurred efficient costs. This may mean raising regulated prices even in circumstances where a gas network service enters into a terminal decline.

Adjusting prices upwards may be contrary to the efficient operation of a declining natural monopoly service industry, such as the Australian postal service. The risk that regulated gas prices may constantly be revised upwards with declines in demand may jeopardise the investments that consumers make in their gas appliances and therefore their gas consumption. This would result in less efficient outcome for the gas network service market.

6.3.3 Do regulated businesses have an obligation to supply service even when it may no longer be economical to do so?

Gas distribution network operators currently have an obligation to provide ‘basic connection services’ to retail customers who request them under the NGR.[142] A ‘basic connection service’ is a service involved in providing a connection between a distribution pipeline and a retail customer’s premises where the provision of the service involves minimal or no extension to, or augmentation of, the distribution pipeline.[143] A gas distribution network operator is required to have in place a model standing offer to provide a basic connection service to retail customer.[144]

However, this obligation to provide basic connection services does not appear to extend to require gas distribution network operators to continue to invest in assets to continue to connect customers to the pipeline where that infrastructure does not already exist. It is also unclear whether a gas distribution network operator may cease servicing particular customers on its network where it may be uneconomical to continue operating the infrastructures that service those customers.

In a wind-down scenario, where gas networks cannot be repurposed and become gradually obsolete, the NGL and NGR as currently drafted do not provide any guidance on how a network may cease its services to customers.

In light of the possibility that gas networks may not be successfully repurposed to transport other gases, the NGL and NGR may need to be amended to provide network service providers with more flexibility to manage the under-utilisation of their networks and the cost of maintaining and operating their networks, while protecting the interests of captive customers during the transition to shut down their networks.

6.3.4 Should gas network businesses be fully regulated on price when there may be effective competition?

The basis for economic regulation of infrastructure is when there are conditions in the market which severely limit effective competition. Such conditions can include large sunk costs and natural monopoly production technology in the supply of the service, as in the case of gas networks.

These conditions limit contestability of the market with the effect that in the absence of regulation, the incumbent can exercise market power by restricting supply and charging prices above efficient costs over a sustained period without eliciting a competitive response. However, it is possible that the market for the services of gas network business may evolve in future and could become

[142] See, generally, Part 12A of the NGR.

[143] NGR, r. 119A.

[144] NGR, r. 119B(1).

effectively competitive. In this scenario, where the costs of full regulation of gas network services may outweigh its benefits, there should be a consideration of light regulation or even recourse to interventions that do not involve any economic regulation. [145,146]

Effective competition in a market exists when there is an opportunity for sufficient influences to constrain the market power of suppliers (eg. rivalry amongst existing suppliers, the threat of substitute goods and services, the threat of new entrants, or the buying power of consumers).[147]

If electricity becomes more competitive against natural gas, and switching costs become immaterial, gas network services may no longer have substantial market power or the incentive to charge monopoly prices absent regulation. The threat of a natural gas substitute, such as electricity or other types of primary energy used for distributed electricity generation, may exert sufficient competitive constraints on the price of gas pipeline services in the future. This may be true in the residential market where customers can readily substitute gas with electricity. However, not all customer segments have access to natural gas substitutes currently, as there are still many industrial customers or vulnerable customers who cannot readily switch to an alternative. These customers would be captive customers.

Notwithstanding the increasing threat of natural gas substitutes, natural gas remains an important and perhaps irreplaceable fuel source for many customers in the short to medium term. The competition between natural gas and its substitutes may depend heavily on governments' policies and technology advancements in lowering renewable energy and storage costs, and in changing industrial processes and appliances that traditionally rely on gas.

Depending on the regulated business's circumstances and technological development of renewable energy in coming decades, there may come a time when it would be more efficient and effective for the regulated business to be subject to less stringent economic regulation, such as the light regulation regime, or other forms of regulation, such as industry codes of conduct, price monitoring and enforcement of competition law.

6.4 Application of the national gas framework to sustainable gases

Some regulated businesses are looking to adapt to the energy transition by exploring the possibility of blending natural gas with bio-methane or hydrogen. There is some ambiguity in the current definition of natural gas in the NGL with respect to natural gas that is blended with other gases that are not methane.

The definition of natural gas in the NGL refers to a substance that –

145 Full regulation requires the service provider to submit an access arrangement to the regulator and have it approved by the regulator.

146 Under light regulation, the pipeline operator determines its own tariffs and can lodge a more limited access arrangement for the regulator to approve. The pipeline operator must publish relevant access prices and other terms and conditions on its website. In the event of a dispute, a party seeking access to the pipeline may ask the AER to arbitrate.

147 New Zealand Competition Commission, *Input Methodologies (Electricity Distribution and Gas Pipeline Services Reasons Paper*, December 2010, p iii.

(a) is in a gaseous state at standard temperature and pressure; and

(b) consists of naturally occurring hydrocarbons, or a naturally occurring mixture of hydrocarbons and non-hydrocarbons, the principal constituent of which is methane; and

(c) is suitable for consumption.

Energy Ministers have agreed on an expedited process to amend the NGL, National Energy Retail Law and subordinate instruments so hydrogen, bio-methane and other renewable gas blends are brought within the national energy regulatory framework.[148]

The introduction of natural gas blends has implications for the scope of regulated gas pipeline services, such as:

- how we may take the costs of repurposing gas pipelines to carry natural gas blends into account
- whether regulated businesses can recover expenditures related to the development and/or delivery of natural gas blends from customers.

6.4.1 Cost recovery of network expenditures necessary to carry natural gas blends

Provided the natural gas blend is defined as a natural gas in the national gas regulatory framework, then expenditures incurred for the purpose of hauling natural gas blends may be recoverable if the expenditures satisfy the new capital expenditure criteria[149] or the criteria governing operating expenditure[150] specified in the NGR (described in sections 5.1 and 5.1.2).

This may be difficult to demonstrate if there is no regulatory obligation to carry natural gas blend and the costs associated with carrying the natural gas blend (such as investments to modify the network to accommodate the natural gas blend) are higher than what would be incurred if unblended natural gas were supplied instead. As such, strong consumer support and demand for natural gas blend may need to be demonstrated to justify the expenditures required to facilitate the haulage of natural gas blend despite the higher costs.

The current regulatory framework provides limited flexibility for the AER to accept expenditures to accommodate natural gas blends when determining efficient costs for gas networks. While this may be perceived as a barrier to the supply of sustainable gases into pipelines, it ensures that consumers pay no more than the efficient cost of receiving natural gas services, which is consistent with the current NGO.

Nevertheless, provided that a regulated businesses demonstrates strong consumer support for expenditures related to the conveyance of natural gas blends, we may consider the expenditures

[148] The Hon Angus Taylor MP, *Energy National Cabinet Reform Committee media release*, 20 August 2021. At the time of this paper, the AEMC had released a public consultation paper that discusses the reforms to the national gas regulatory framework to accommodate natural gas equivalents. See AEMC, *Review into extending the regulatory frameworks to hydrogen and renewable gases, Consultation paper*, 21 October 2021.

[149] NGR, r.79.

[150] NGR r.91.

as prudent and efficient to cater for consumer preferences. For example, in our final decision for Australian Gas Networks (AGN) (SA) 2021-26 access arrangement, we accepted AGN's proposal to incur higher costs for obtaining 20% of its 'unaccounted for gas' from biogas because of the strong customer support it had garnered for this proposal.[151]

6.4.2 Cost recovery of research and development projects to repurpose gas networks to carry gases other than natural gas

In order to establish the necessary capital works required for the network to accommodate natural gas blends and/or sustainable gases such as renewable hydrogen, regulated businesses are likely to have to incur research and development costs to determine the feasibility of repurposing their networks for other gases. Expenditures incurred for such purposes are experimental in nature. To allow the cost recovery of such expenditures from consumers would mean that consumers bear the risks of these expenditures.

We are beginning to see some regulated gas businesses undertaking research and development or trial projects to blend natural gas with bio-methane or hydrogen.[152] We consider that the risks of these projects are best managed by the regulated businesses and should be allocated to them, not consumers. Our preliminary view is that these expenditures would not be considered as conforming capex.

We adopted this approach in our final decision for Jemena Gas Networks (JGN) (NSW) 2020-25 access arrangement. We allowed the opening of a speculative capex account, which applies to non-conforming capex, to account for the expenditures associated with JGN's research trial (Western Sydney Green Gas Trial) that sought to ascertain the future potential of hydrogen as an alternative fuel source. This allows JGN to recover the capex in future years if it conforms to the NGR at such time.[153]

It may be argued that if regulated businesses are not guaranteed to recover the costs of these development or trial projects, they may not have sufficient incentives to invest in them and this may not be in the long-term interests of gas consumers. However, the long-term commercial viability of the regulated businesses hinges upon their ability to repurpose their assets to deliver natural gas substitutes and to cultivate consumer demand for those substitutes as soon as practicable. It is our view that regulated businesses have an incentive to innovate and explore options to increase and maintain consumer demand of pipeline services, thereby extending the economic lives of their assets and their commercial viability, particularly in the current circumstances where their future revenues are no longer assured due to the emerging competition from alternative energy sources.

6.4.3 Ring-fencing for sustainable gas production

Expenditure related to the production of sustainable gases should not be recovered from consumers in the form of gas access prices. While the predominant purpose of producing these

[151] AER, *Final decision – Australian Gas Networks (SA) Access Arrangement 2021-26 Overview*, April 2021, p. 7.

[152] Jemena Gas Network (JGN) is currently undertaking a trial project to modify an existing water treatment plant at Malabar to allow for the injection of renewable gas (biomethane) into the JGN network in NSW.

Australian Gas Infrastructure Group's Hydrogen Park South Australia project produced renewable hydrogen in late 2020 and began blending hydrogen with natural gas to supply to nearby homes via the existing gas network.

[153] AER, *Final decision – Jemena Gas Networks (NSW) Ltd Access Arrangement 2020-25 Overview*, June 2020, pp. 8, 41.

gases may be to explore the possibility of hauling sustainable gases in existing gas networks, the cost of production should be reflected in the supply cost of the sustainable gas itself and not gas access prices.

The production of bio-methane and hydrogen, as well as natural gas blending, are at an infancy stage and they have yet to be proven economical. Nevertheless, as the production of hydrogen or bio-methane develops as an industry, we need to be mindful of the evolving competition dynamics in the sustainable gas market. In particular, regulated network businesses who produce sustainable gases may be able to exercise market power in the sustainable gas market with first mover advantage, or to subsidise their gas production businesses with their regulated revenues from providing network services. The technical constraints on a gas network to carry hydrogen more than a specified safety threshold (which is currently about 10%) may also add to the complexity of ensuring other hydrogen producers have adequate access to the gas networks.

The NGL currently imposes minimum ring-fencing requirements on regulated service providers, requiring them to keep separate accounts in respect of regulated pipeline services.[154] The NGL further provides that the AER may make a determination to impose additional ring-fencing requirements.[155, 156]

Issues for consideration

14) Should the NGR be amended to allow the AER to give special consideration to expenditures related to the haulage of natural gas blends?

15) Should the NGR be amended to support efficient investments in the investigations, trials and exploratory projects to repurpose gas networks? If yes, how should we allocate the risk and cost of such projects between network businesses and consumers?

16) What additional ring-fencing requirements may be necessary to ensure that regulated network businesses maintain competitive neutrality in the market of sustainable gas production in the future?

[154] NGL, ss. 139 – 141.

[155] NGL, s. 143.

[156] As part of its review into extending the regulatory frameworks to hydrogen and renewable gases, the AEMC identified ring fencing arrangements for pipelines as one of the issues that may need to be addressed in the NGR to effectively accommodate the supply of natural gas equivalents. See AEMC, *Review into extending the regulatory frameworks to hydrogen and renewable gases, Consultation paper*, 21 October 2021, pp.11-12.

Appendix A – Energy transition initiatives in six Australian jurisdictions

This appendix outlines the energy transition initiatives that the AER is currently aware of in six Australian jurisdictions. These initiatives may evolve or change over time. This table is by no means an exhaustive list of governments' energy transition initiatives.

	Federal	ACT	New South Wales	Queensland	South Australia	Tasmania	Victoria
Emissions Targets[1]	26-28% reduction on 2005 levels by 2030 Net zero by 2050[2] Long-Term Emissions Reduction Plan[3] Technology Investment Roadmap[4]	Net zero by 2045; 50–60% below 1990 levels by 2025 [5]	Net zero by 2050 and 50% below 2005 levels by 2030[6]	Net zero by 2050 and 30% below 2005 levels by 2030[7]	Net zero by 2050 and 50% below 2005 levels by 2030 (currently legislated at 60% reduction of 1990 levels by 2050)[8]	Net zero by 2050. No official 2030 target but by 2017 it was already 95% below 2005 levels[9]	Net-zero by 2050, with five-yearly interim emissions reduction targets, the first two being 28–33% for 2025 and 45–50% by 2030 below 2005 levels[10]
Renewables Targets[11]	Renewable Energy Target Scheme: 33,000 GW hours of additional renewable electricity generation by 2020 (achieved in 2021)[12]	100% renewable electricity supply from 2020[13]	Delivering 12 GW of new transmission capacity through renewable energy zones and supporting 3 GW of storage and firming projects by 2030 under the Electricity Infrastructure Roadmap	50% renewable energy by 2030	100% net renewable energy generation by 2030.[14]	100% renewable electricity by 2022 (achieved in 2020) By 2040, 200% of the baseline of 10,500 GWh per year[15]	Victorian Renewable Energy Target (VRET) of 50% by 2030
Electric Vehicle or Zero Emissions Vehicle Policies[16,17]	The Future Fuels and Vehicles Strategy (2021) focuses on five priority initiatives: Providing convenient access to electrical vehicle charging and hydrogen refuelling infrastructure; early focus on commercial fleets; improving information for motorists and fleets; integrating battery electric vehicles into the electricity grid; supporting Australian innovation and manufacturing.[18]	EV buyers qualify for up to $15,000 in interest-free loans, full stamp duty exemption for new sales, and 2 years of free registration on zero emissions vehicles[21] Transition to Zero Emissions Vehicles Action Plan 2018-21 detailed a range of government commitments, including the goal that all newly leased ACT Government passenger fleet vehicles will be	NSW Net Zero Plan Stage 1: 2020-2030 (2020) and NSW Electric and Hybrid Vehicle Plan (2019)[24] The NSW Electric Vehicle Strategy (2021) includes rebates, phased removal of stamp duty for EVs, targets for NSW Government fleet, incentives for council and private fleets, and major investment to ensure widespread EV charging coverage. The	The Future is Electric: Queensland's Electric Vehicle Strategy (2017) identifies 16 government programs to prepare for the transition to EVs grouped into themes of Empower (community awareness and innovation strategies), Enable (develop charging network), Explore (electrify government fleet, feasibility studies) Envisage (mobility	Electric Vehicle Action Plan (2020) identifies 10 actions across four themes: state-wide public charging network; leading by example (government fleet and municipal buses); catalyse fleet and private uptake; and a framework to speed up transition.[28] The plan includes $13.4 million to co-invest in Electric Vehicle Charging Network; $3.6 million in Electric	Electric Vehicle ChargeSmart Grants Program[30] Established Electric Vehicle Working Group to develop a coordinated approach to support the uptake of electric vehicles.[31] Target to transition the Tasmanian Government fleet to 100 per cent electric vehicles by 2030; stamp duty exemption for the purchase of new, or second-hand,	Zero Emissions Vehicle Roadmap (2021)[33] indicates a target of 50% of vehicles sales by 2030 to be zero emissions vehicles (ZEVs) and a target for all public transport bus purchases to be ZEVs from 2025. Supported by $100m package including 20,000 subsidies of up to $3,000 for new electric vehicle purchases under $69,000[34] and $100 registration discount for EVs and

	A $250 million Future Fuels Fund will support: public electric vehicle charging and hydrogen refuelling infrastructure, heavy and long-distance vehicle fleets, light vehicle commercial fleets, and household smart charging.[19] Electric Vehicle Grid Integration Workstream[20]	zero emissions vehicles from 2020–21 (where fit for purpose).[22] The Zero Emissions Vehicle Public Charging Masterplan to rollout of charging infrastructure, including 50 publicly accessible charging stations.[23]	strategy is intended to increase EV Sales to 54% by 2030-31.[25]	trends, electric public transport). [26] The QLD Government is currently developing the Zero Emission Vehicle Strategy, which will supersede the existing 'The Future Is Electric' Strategy.[27]	Vehicle Smart Charging Trials; and transitioning the government's 6,800 passenger vehicle fleet to EVs.[29]	battery electric or hydrogen fuel cell vehicles, for a two-year period; waiving registration fees for electric vehicles purchased by rental car or tour bus companies for a period of two years; and supporting Metro Tasmania to trial zero emissions buses.[32]	hybrids; $19 million funding commitment to establishing electric vehicle fast-charging network[35]; $20m bus trial; $10m for 400 ZEV government vehicles; $298,000 for an EV-readiness in new buildings study; $5 million to establish a commercial sector Zero Emissions Vehicle Innovation Fund.
Hydrogen Aspirations[36,37]	National Hydrogen Strategy[38] - identifies an adaptive pathway of foundational scale up activities to 2025, and large-scale market activation beyond 2025, supported by enabling activities. National Energy Resources Australia (NERA) has formed a network of 15 hydrogen technology clusters across Australia[39] Under the Technology Investment Roadmap[40], a $1.2 billion investment is committed to accelerate the development of Australian hydrogen industry, including $464 million to develop up to seven Clean Hydrogen Industrial Hubs in regional Australia.[41] $300 million Advancing Hydrogen Fund, administered by CEFC[42] ARENA funding $103 million to support three	Hydrogen Mobility Demonstration project - 20 hydrogen government fleet vehicles and refuelling infrastructure[46] The ACT government has established several renewable hydrogen projects including: a test facility for examining how to reticulate hydrogen in existing gas network, a hydrogen refuelling station; and the ACT Renewable Hydrogen Cluster.[47]	The NSW Hydrogen Strategy will provide up to $3billion to support the development of a hydrogen industry in the state. The Strategy aims to produce up to 110,000 tonnes of green hydrogen per annum by 2030 and become a major exporter of hydrogen. Supporting Hydrogen R&D through the Clean Technology Innovation focus area of the $750 million Net Zero Industry and Innovation Program[48] NSW Government has set an aspirational target of 10% hydrogen blending in gas networks by 2030 as part of its 'Net Zero Plan Stage 1: 2020-2030'.[49]	Queensland Hydrogen Industry Strategy 2019-2024 (2019) nominates five focus areas: supporting innovation, facilitating private sector investment, ensuring an effective policy framework, building community awareness and confidence, facilitating skills development for new technology, and associated actions. A$15 million Hydrogen Industry Development Fund. Five hydrogen fuel cell vehicles in government fleet as part of its trial of fuel cell EV technology[50] $2 billion Queensland Renewable Energy and Hydrogen Jobs Fund to finance renewable energy and hydrogen projects.[51]	South Australian Green Hydrogen Study (2017), A Hydrogen Roadmap for South Australia (2017) South Australia's Hydrogen Action Plan (2019)[52] outlines 20 actions across five themes: facilitate investments in hydrogen infrastructure; establish a world-class regulatory framework; deepen trade relationships and supply capabilities; foster innovation and workforce skills development; integrate hydrogen into our energy system. Hydrogen Export Prospectus (2020)[53] identifies three hydrogen hubs.	Tasmania Renewable Hydrogen Action Plan (2020) identifies four focuses: explore opportunities for locally produced renewable hydrogen; financial support for hydrogen projects and investment attraction activities; supportive regulatory framework and assess supporting infrastructure; community and industry awareness, develop skills, and support research and education. By 2030, goal is to be a significant global producer and exporter of hydrogen. As part of the Tasmanian Renewable Action Plan, $50 million has been committed to develop a green hydrogen economy and become and exporter by 2025 and a global export hub by 2030.	Victorian Hydrogen Investment Program (2018), Victorian Green Hydrogen Discussion paper (2019) and Zero Emissions Vehicle Roadmap Renewable Hydrogen Industry Development Plan (2021)[54] identifies three focus areas: foundation for renewable hydrogen (R&D, safety, workforce skills and education); connecting the economy (gas networks, exports, integration with renewables); leading the way (pilots and demonstrations, community awareness, government initiatives) Hydrogen Energy Supply Chain Pilot Victorian government is a founding member of the Australian Hydrogen Centre and is supporting a series of feasibility studies

	commercial-scale hydrogen electrolyser projects.[43] $24.9 million funding to enable hydrogen capable gas power generators.[44] Legislative reform to the national gas regulatory framework to expand its scope to include hydrogen blends, biomethane and other renewable gases.[45]						examining hydrogen blending in the natural gas network.
Support for Batteries	ARENA and CEFC provide funding support for projects involving battery storage.[55] The Government will provide $49.3 million for battery and microgrid projects.[56]	Next Generation Energy Storage Grants[57] - eligible installers can apply Sustainable Household Scheme [58] - zero-interest loans of between $2,000 to $15,000 for a range of energy products	Empowering Homes solar battery loan[59] - $14,000 towards a solar PV and battery system (repayable over a range of terms up to 8 years), or $9,000 towards retrofitting a battery system to an existing solar PV system (repayable over a range of terms up to 10 years). Smart Distributed Batteries Project[60] - point of sale discount for VPP enrolment	Renewable Energy and Hydrogen Jobs Fund also supports battery storage projects.	$100 million Home Battery Scheme[61] $50 million Grid Scale Storage Fund[62]		Support for three large-scale batteries in Western Victoria[63] Procurement of the 300 MW/450 MWh Victorian Big Battery[64] Solar Homes Program - Solar battery rebate[65] - point of sale discount where eligible up to a maximum of $4,174. Soon to expand to include aggregation option.
Domestic Solar PV Support	Small-scale Renewable Energy Scheme[66]	Solar for Low Income Households Program[67] - 50% subsidy capped at $2,500 for eligible households	Empowering Homes solar battery loan[68] - $14,000 towards a solar PV and battery system (repayable over a range of terms up to 8 years).				Solar Homes Program – Solar PV Rebate[69] - up to $1,850 rebate for solar panel (PV) system installation, for homeowners and rental properties
Renewable Energy Zone (REZ) Commitments	ARENA and CEFC provide funding support for projects that enable the development of REZs.[70][71]		Will develop REZs in five locations as set out in its Electricity Infrastructure Roadmap[72]	Committed $145 million to establish three REZs[73]		Released draft Renewable Energy Coordination Framework for public consultation to consider the development of three REZs.[74]	Pledged $543 million to fund six REZs[75] administered by new body VicGrid[76]

Other Industry Support	National Greenhouse and Energy Reporting (NGER) scheme[77] Offshore Renewable Energy Regulatory Framework[78] Snowy Hydro Snowy 2.0 Project[79] Snowy Hydro Hunter Power Project[80] - Kurri Kurri Gas Plant Bilateral Energy and Emissions Reduction Agreements (State Deals) with NSW (2020), Tas (2020) and SA (2021)[81] Emissions Reduction Fund[82] and Safeguard Mechanism[83] $250 million Carbon Capture, Use and Storage (CCUS) Hubs and Technologies program and $50 million CCUS Development Fund[84] The Underwriting New Generation Investments (UNGI) program [85] Post-2025 reform package for the National Electricity Market[86]	$100 million committed to delivering a 'Big Canberra Battery'[87] The Zero Emissions Government fund[88]	Net Zero Industry and Innovation Program[89]	$500 million Renewable Energy Fund to support renewable energy projects[90]	$150 million Renewable Technology Fund (2017)[91]		$108 million for an Energy Innovation Fund[92] $20 million New Energy Jobs Fund[93] $13 million Microgrid Demonstration Initiative[94] $10.92 million Neighbourhood Battery Initiative[95] Renewable Communities Program[96] Household Energy Savings Package[97] Yallourn Closure Support[98] [99]

Source: Energy Security Board; Department of Industry, Science Energy and Resources; and AER.

Note: Current as of November 2021.

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