APRIL 2021 | GAS INFRASTRUCTURE ADVICE – LITERATURE REVIEW

Literature Review

Gas Infrastructure Advice

Final version

INFRASTRUCTURE VICTORIA

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1. Introduction

Background

The fifth Synthesis Report of the Intergovernmental Panel on Climate Change (IPCC) provides the most recognised scientific analysis of the role of human influence on the climate system. Recent anthropogenic emissions of greenhouse gases are the highest in history. Continued greenhouse gas emissions will cause further warming and long-lasting changes in the climate, increasing the likelihood of severe, pervasive, and irreversible impacts for people and ecosystems. To slow or limit these risks, humanity must both adapt to a changing climate and take measures to reduce greenhouse gas emissions (IPCC 2014).

Countries and their jurisdictions have committed to reduce and manage the risk of climate change around the world. In 2017, the Victorian Parliament created the *Climate Change Act 2017* to establish a long-term emissions reduction target of net zero by 2050.

Natural gas is a naturally occurring gas that primarily consists of methane. The fossil fuel is made from carbon-rich, decomposed plants and animal matter subject to intense heat and pressure under the Earth's surface for millions of years. The combustion of natural gas produces environmentally harmful greenhouse gases like CO_2, contributing to a changing climate. In 2018, the energy sector in Victoria produced 89.5% of Victoria's total net emissions, including electricity generation, direct combustion, transport, and fugitive emissions from fuels.

The cost of energy is also a key influence on living and doing business in Victoria. Victoria has Australia's largest network of natural gas infrastructure, providing over two million households and businesses with natural gas. Natural gas combustion is used as an energy source in the energy sector for industrial and residential heating, cooling, and electricity generation. Compressing natural gas into a liquid form is also used in the transport sector as a fuel for vehicles. In the chemical industry, natural gas is used as an industrial fuel and chemical feedstock to produce ammonia as a fertiliser.

While many national and global studies focus on the emissions impact of the electricity sector, the gas sector has not been fully considered. The exact pathway forward to decarbonise gas technology and infrastructure domestically and internationally is not yet known. There are several uncertainties: First, there are uncertainties as to which technologies can be applied to achieve decarbonised gas infrastructure. Second, the development of pathways and scenarios, timing, scale, and growth trajectories are uncertain. Finally, economic, social, and environmental impacts on costs and benefits of those pathways are unknown.

Scope of Advice

The Victorian Government has asked Infrastructure Victoria to advise on the nature and timing of decisions relating to Victoria's extensive gas transmission and distribution networks in 2050 where: net zero emissions are economy-wide sufficient, and suitable energy and chemical feedstocks are available for domestic, commercial, and industrial use; and hydrogen and biomethane solutions are viable.

To inform this advice, Infrastructure Victoria will engage with industry, government, regulators, consumer groups and other key stakeholders and seek out evidence to inform our recommendations. Infrastructure Victoria will also complement and build upon existing state and federal strategies, policies, and regulatory frameworks, including *Victoria's Gas Roadmap* funded in the 2020-21 State Budget, led by the Department of Environment, Land, Water and Planning (DELWP).

The advice will examine two or more appropriate scenarios for a net zero emissions energy sector in 2050 and assess their relative economic, social, and environmental impacts. It will explore the implications of these for gas production, electricity generation, and transmission and distribution networks, identifying the infrastructure decisions that need to be made, and the timing of these decisions.

Infrastructure Victoria will consider the extent to which gas infrastructure can be used for hydrogen, carbon capture and storage (CCS) and/or biomethane, where existing gas infrastructure can be optimised, and the role for the Victorian Government in supporting these technologies as they transition. Our advice will also assess the cost and reliability impacts of key infrastructure decisions, including how to minimise the social, environmental, and economic costs to businesses, industry, and the community.

At the request of the Victorian Government, our analysis will also examine key uncertainties, trigger points and interdependencies associated with the infrastructure decisions identified, including any significant risks and mitigation options.

Our advice takes a multi-disciplinary approach to research, drawing on analysis from interstate and international jurisdictions. Existing available evidence and modelling will be used where it is available, and the sources of that evidence clearly identified. The analysis will consider the implications for gas infrastructure relative to related trends, such as the use of zero-emission vehicles, low emission fuels, industry transitions, and sector pledges to reduce greenhouse gas emissions.

Scope of Literature review

This review presents key issues and opportunities identified in current literature sourced from academia, industry, think-tanks, and governments. The reviewed literature contributes to our understanding of the critical risks and opportunities towards net zero emissions for Victoria's gas infrastructure. The literature review helps to understand where the gaps are in the current evidence and what further research may be needed to inform our final advice. This review is not intended to be a comprehensive analysis of all literature related to gas infrastructure in a net zero emissions electricity sector. Instead, it is targeted areas relevant to our advice. In particular, the literature review addresses the following questions:

1. What are the key risks and opportunities for existing natural gas transmission and distribution infrastructure in relation to achieving net zero emissions in Victoria by 2050, particularly in relation to hydrogen, biomethane and carbon capture and storage (CCS)?

2. What pathways have been proposed to replace:
    a. energy, and
    b. chemical uses of natural gas?

3. What is the technical and commercial maturity of those pathways?

4. What modelling, if any, has been conducted that can assist our understanding of the environmental, social, and economic (ESE) costs and benefits of the transition to net zero emissions for the gas sector in Victoria?

5. What are the key assumptions and conclusions?

6. What is the role of the government?

2. Literature review

The purpose of this literature review is to identify critical risks and opportunities for gas infrastructure as Victoria transitions to net zero emissions by 2050.

Section 2.1 outlines the current role of gas infrastructure in Victoria, while section 2.2 covers the three technologies currently being developed to support decarbonisation: hydrogen, biogas and carbon capture and storage (CCS). Section 2.3 Analysis of decarbonisation pathways illustrates options to replace energy and chemical uses with natural gas. Finally, section 2.4 examines the Role of government in achieving the net zero emissions of the gas infrastructure globally and locally in Victoria. Chapter 3 summarises key findings and answers the key questions of the literature review.

2.1 Victorian gas infrastructure

Section 2.1 identifies critical risks and opportunities for gas infrastructure in Victoria to 2050.

2.1.1 Gas value chain

Victorian gas infrastructure is defined as the entire value chain of consumption, production, export, gas shortfall, transmission and distribution, storage, and end-use.

Energy consumption

Primary energy consumption measures the total amount of energy demand in an economy, including the energy sector's consumption, its energy losses during the transformation from oil or gas into electricity, its energy distribution, and the final consumption by its end users, including domestic use and export.

Energy consumption by state

The amount and mix of energy sources used in each Australian state vary widely. Victoria has the third-largest energy consumption with a share of 20.9% (see Table 1). Since 2008-09, Victoria’s energy consumption has fallen by around 1.0%, mainly due to the shift from coal-fired electricity generation to renewable energy. This fall can be attributed largely to small-scale and large-scale solar and wind power (DISER 2020a).

Table 1: Australian energy consumption by state and territory in 2018-19 (DISER 2020a)

	Energy consumption in 2018-19		Average annual growth	
	PJ	Share in %	2018-19 in %	10 years in %
NSW & ACT	1,540.6	24.9	-0.3	-0.7
VIC	1,297.6	20.9	-1.5	-1.0
QLD	1,525.3	24.6	-1.8	1.8
WA	1.261.0	20.4	4.5	3.7
SA	322.6	5.2	-3.8	-0.7
TAS	108.8	1.8	-1.9	-0.6
NT	140.1	2.3	53.8	4.5
AUS	**6,196.00**	**100**	**0.6**	**0.7**

Energy consumption by fuel type

In 2018-19, most (95%) of Victoria's energy came from fossil fuels. Oil, (including crude oil, liquefied natural gas (LNG), and refined products), account for the largest share of energy consumption with 39%, followed by coal (34%) and gas (22%), the third-largest energy consumption. In 2018-19, renewable energy accounted for 6% of Victoria's total energy consumption (DISER 2020a).

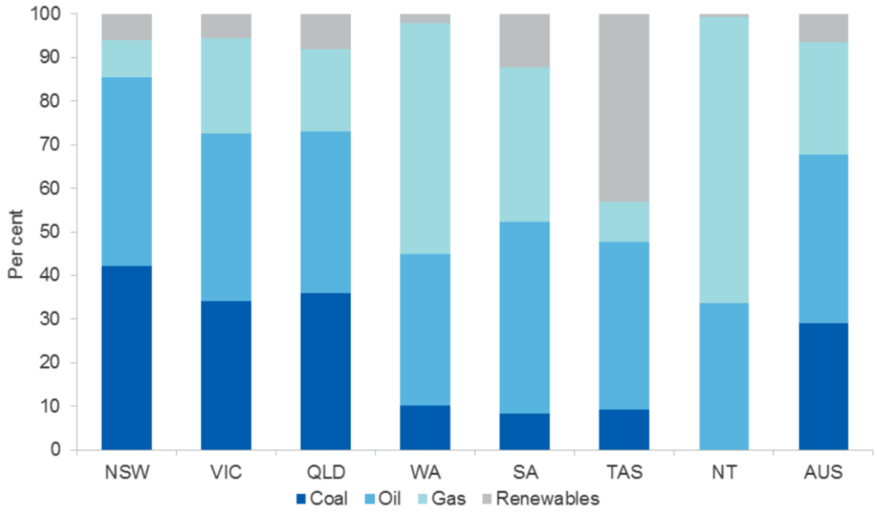


Figure 1: Australian energy mix, by state and territory in 2018–19 (DISER 2020a)

Victoria is very similar to the national average (refer to Figure 1) with fossil fuels accounting for 94% of Australia's energy consumption in 2018-19. Oil accounts for the largest share of energy consumption (39%) followed by coal (29%) and gas (27.5%). In 2018-19, gas consumption increased by 2% with the expansion of LNG exports (DISER 2020a).

Table 2 shows Victoria is the third-largest gas consumer compared to other Australian states. Including domestic use and export processing, gas accounted for 42% (668.7 petajoules (PJ)) of energy consumption in Western Australia, 18.4% (292.6 PJ) in Queensland, closely followed by Victoria with 17.8% (283.9 PJ) (DISER 2020a).

Table 2: Australian primary energy consumption by fuel type in 2018-19 (DISER 2020a)

	Energy consumption 2018-19 in PJ				
	Coal	Oil	Gas	Renewables	Total
NSW & ACT	640.3	657.9	131.4	90.4	**1,540.6**
VIC	444.1	501.3	283.9	72.0	**1,297.6**
QLD	554.0	574.6	292.6	123.9	**1,525.3**
WA	126.8	438.6	668.7	26.8	**1,261.0**
SA	26.3	141.1	114.1	39.0	**322.6**
TAS	10.0	41.6	10.0	46.6	**108.8**
NT	-	47.0	91.9	1.1	**140.1**
AUS	**1,801.6**	**2,402.1**	**1,592.7**	**399.6**	**6,196.0**

Although natural gas consumption in Western Australia and Queensland is higher than Victoria, consumption is driven mainly by gas-fired power generation (GPG) and mining (refer to Figure 2). Victoria is the highest user of residential and commercial gas.

The next step is to analyse how energy demand is met and how much energy Australia needs.

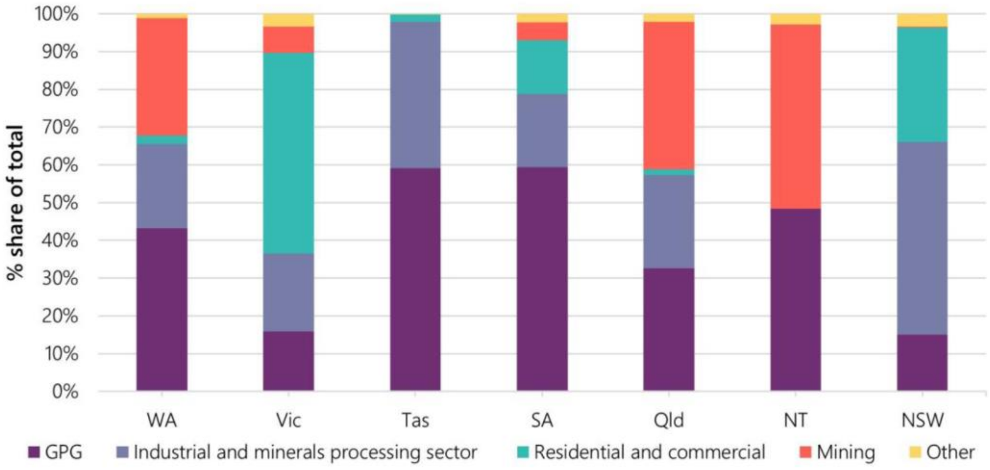


Figure 2: Major category gas consumption by state (% share of total) in 2018-19 (AEMO 2020a)

Energy production

Primary energy production is defined as the total amount of primary energy produced in the Australian economy, measured before consumption or transformation into secondary energy products, e.g., coal into electricity.

Australian gas production

Looking at gas production only, Australia produced in total 5,498.1 PJ of natural gas in 2018-19 (see Table 3). Conventional gas accounted for around three-quarters, and coal seam gas (CSG) one-quarter of the Australian gas production. Western Australia produces around 60% of Australian gas, followed by Queensland (25%) and Victoria (9%) (DISER 2020a).

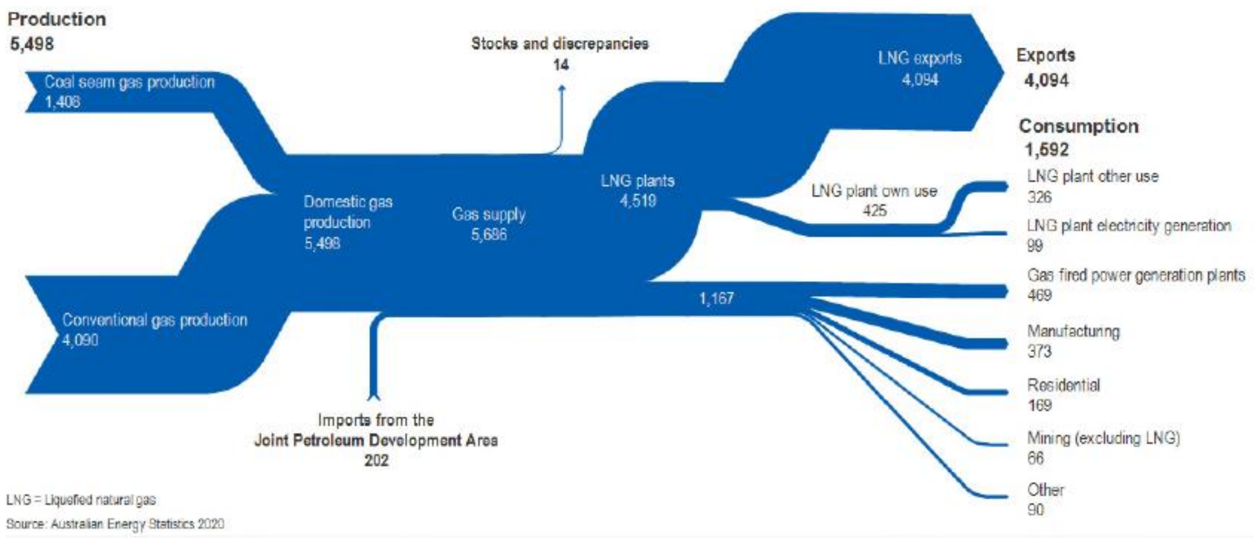
Table 3: Australian production of gas in 2018-2019 (DISER 2020a)

	Gas production in 2018-19			
	Conventional gas in PJ	**CSG in PJ**	**Total in PJ**	**Total in %**
NSW & ACT	-	3.8	**3.8**	**0.1%**
VIC	517.2	-	**517.2**	**9.4%**
QLD	37.7	1,404.4	**1,442.1**	**26.2%**
WA	3,350.4	-	**3,350.4**	**60.9%**
SA	121.0	-	**121.0**	**2.2%**
TAS	-	-	**-**	**0.0%**
NT	63.6	-	**63.6**	**1.2%**
AUS	**4,090.0**	**1,408.1**	**5,498.1**	**100%**

Gas export

Comparing Australia’s total gas production with its gas consumption, it can be seen that most of Australia’s gas producution is exported. Having a closer look at Australia’s gas flows (see Figure 3), the majority of Australia’s gas production (72% or 4,094 PJ) is exported as LNG (DISER 2020a). A large amount of energy is needed to convert natural gas into LNG. With a share of 7.5% (or 425 PJ), the second-biggest consumer of gas in Australia is the gas industry itself (Climate Council 2020b).

A total of 20.5% (or 1,167 PJ) of gas consumption is domestically used for gas-fired power generation (8.2% or 469 PJ), manufacturing (6.6% or 373 PJ), residential (3.0% or 169 PJ), and mining (1.2% or 66 PJ) (DISER 2020a).



LNG = Liquefied natural gas

Source: Australian Energy Statistics 2020

Figure 3: Australian natural gas flows, in PJ, 2018–19 (DISER 2020a)

Victorian gas shortfall

The Victorian Gas Planning Report (VGPR) provides an overview of the gas transmission network planning for Victoria. The majority of Victoria's natural gas is produced in the Gippsland Basin and processed at the Longford gas plant (refer to Table 4). Natural gas is also supplied from other gas fields in Gippsland, Otway Basins, offshore from the Bass Coast area and interstate (AEMO 2021b).

Table 4: Victorian gas production facilities (AEMO 2021b)

System Withdrawal Zones (SWZ)	Total available in 2020	Gas plant	Project	Project ownership
Gippsland	316 PJ	Longford Gas Plant	Gippsland Basin Joint Venture	• Esso Australia Resources, 50% • BHP Billiton Petroleum, 50%
			Kipper Unit Joint Venture	• Esso Australia Resources, 32.5% • BHP Billiton Petroleum, 32.5% • Mitsui, 35%
		Lang Lang Gas Plant	BassGas Project	• Beach Energy Limited, 53.75% • Mitsui, 35% • Prize Petroleum International, 11.25%
		Orbost Gas Plant	Sole Gas Project	• Cooper Energy, 100%
Port Campbell (Geelong)	44 PJ	Otway Gas Plant	Otway Gas Project	• Beach Energy Limited, 60% • O.G Energy, 40%
			Halladale/Speculant Project	• Beach Energy Limited, 60% • O.G Energy, 40%
		Iona Gas Plant	Iona UGS	• QIC, 100%
			Casino Henry Joint Venture	• Cooper Energy, 50% • Mitsui, 50%
		Minerva Gas Plant	Casino Henry Joint Venture	• Cooper Energy, 50% • Mitsui, 50%

Victoria’s gas demand has been relatively constant over the last five years. In 2020, Victoria consumed 220 PJ. By 2025, Victoria’s annual gas demand is forecast to decline 12.7% to around 191 PJ. The decline in consumption is due to uncertainties around renewable energy output, the existing Victorian Energy Upgrades (VEU) program to upgrade gas appliance efficiency, the end of gas production in some fields, the timing of proposed investments in new generation, and variable gas prices (AEMO 2020b, AEMO 2021b). Monthly natural gas consumption fluctuates widely, and the average daily is about three times higher in winter than in summer. For example, during winter 2021, from June to August, maximum monthly system consumption is forecast to be over 25 PJ per month (PJ/m). During summer 2021, from December to February, natural gas consumption is forecast to be less than 10 PJ/m (AEMO 2021b).

Victoria produced 361 PJ of natural gas in 2020 (see Table 5)[1]. Overall production from existing gas production facilities is forecast to decline by 43% from 2021 to 2025. In 2024, critical Gippsland gas fields and other smaller gas fields that supply the Longford gas plant are forecast to cease production. That is earlier than the forecast in the 2020 VGPR Update. Victoria can prevent the predicted gas shortfall from 2024 due to additional gas supply, mainly from gas import terminals in NSW (AEMO 2021b). In the past, Victoria could export more natural gas than import, making Victoria a net exporter over the average year. With anticipated investment in new import infrastructure, Victoria can prevent the gas supply shortfall from 2024, which was forecasted in VGPR 2020.

Table 5: Forecast Victorian annual gas consumption and production, 2021-25, with 2019 and 2020 actuals (AEMO 2020b, AEMO 2021b)

	2019 (actual)	**2020 (actual)**	**2021**	**2022**	**2023**	**2024**	**2025**
Total VIC available production in PJ	343	361	360	341	287	261	205
Imports from NSW in PJ	0	0	0	0	60	60	60
Total VIC consumption in PJ	232	220	207	202	198	195	191
Surplus quantity with VIC and NSW available supply in PJ	**111**	**145**	**154**	**139**	**149**	**126**	**74**

In 2017, the Victorian Government imposed a moratorium on all onshore conventional gas exploration and development, the *Resources Legislation Amendment (Fracking Ban) Act 2017*. With the *Constitution Amendment (Fracking Ban) Bill 2020* the permanent ban on fracking and the enshrining of unconventional gas (coal seam and shale gas) in Victoria remains in place (Premier of Victoria, The Hon Daniel Andrews 2021).

The restart of the onshore conventional gas sector is on track for 1 July 2021, after three years of detailed scientific investigations by the Victorian Gas Program (VGP). The Victorian Government's geoscience agency undertook scientific, technical, environmental and social studies to assess the risks, benefits and impacts of new onshore conventional gas (Geological Survey of Victoria 2020). The VGP identifies potential new onshore conventional and offshore gas resources, as well as new underground gas storage. The geoscientific investigations conclude that there is likely to be 128-830 PJ of commercially feasible onshore conventional gas yet to be discovered in Victoria.

Potential locations include the Otway Basin in south-west Victoria and Gippsland in south-east Victoria. The VGP has also started to support commercial exploration of new offshore gas, with environmental controls in place to protect Victoria's coastal areas. The exploration permit is the beginning of the offshore exploration process, including desktop research and modelling, and is expected to take several years. There is no guarantee that the exploration will produce new offshore gas fields (Geological Survey of Victoria 2020).

The VGP states the production of these resources could help avoid a predicted gas shortfall. Further, new gas resources would generate around AUD $300 million annually for regional economies and create up to 6400 jobs. The VGP also states that this additional gas resource production would have a "negligible" impact on Victoria's greenhouse gas emissions (Geological Survey of Victoria 2020).

Several projects to improve the annual gas supply balance in the short-term have started to prevent the possible gas shortfall in Victoria. Projects include (AEMO 2021b):

- The anticipated development of two major gas fields that are processed through the Longford Gas Plant increases the available gas supply until 2025.
- The potential construction of LNG terminals to import gas from Australian or international export facilities. The AGL Crib Point project to the east of Melbourne just has been rejected due to environmental concerns (AGL 2021). The Viva project in Geelong and the Vopak project at Avalon, both to the west of Melbourne, is not expected to be available until 2024.
- Proposed pipeline projects outside of Victoria can increase gas supply in the South-East gas market. Australian Industrial Energy (AIE) committed to proceeding with constructing the 500 terajoules per day (TJ/d) Port

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[1] *There is a discrepancy between DISER's and AEMOs gas production capacities based on differences in acquired data and reporting time frame.*

Kembla LNG import terminal in NSW. Jemena committed to modifying the Eastern Gas Pipeline (EGP) to enable reverse flow from Port Kembla into the Victorian DTS. AIE and Jemena will have completed these projects ahead of winter 2023.

- Distributed gas supply of biogas and hydrogen does not produce significant quantities to prevent a gas shortfall within the next five years' outlook period. Until 2025, distributed gas supply projects are expected to produce less than 100 TJ per year. From 2025 to 2030, there is potential for this quantity to increase up to 4-5 PJ per year.

Gas transmission and distribution networks

Victoria has a Declared Wholesale Gas Market (DWGM). Victoria has a significant natural gas distribution network and storage facilities to help meet demand peaks and significant interconnections with other states. Victoria's gas networks comprise a transmission network owned by one market participant (APA) and three distribution businesses based on geographic regions (see Table 6). Victoria's gas network extends over 30,000 kilometres and provides over two million end-users with gas. The gas infrastructure is valued at nearly AUD $6 billion, with network operators generating an annual revenue of nearly AUD $700 million and investing $345 million in 2019-20 (AER 2020).[2]

Victoria's net zero emissions targets coupled with falling costs of renewable energy could mean this immense gas infrastructure could become an underutilised or stranded asset long before the end of its useful life of 30 to 40 years (Global Energy Monitor 2020).

Table 6: Victoria's gas networks in numbers (AER 2020)

Network	Type	Customer numbers	Length in km	Asset base in $ million	Annual investment in $ million	Annual revenue in $ million
APA Victorian Transmission System	Transmission	n/a	1,992	1,074	50	109
AusNet Services	Distribution	710,000	11,650	1,727	99	175
Multinet	Distribution	687,000	9,866	1,321	82	176
Australian Gas Networks	Distribution	613,454	10,447	1,811	114	228
Total		**2,010,454**	**33,955**	**5,933**	**345**	**688**

Figure 4 shows a map of the Victorian gas transmission network.

The Victorian Declared Transmission System (DTS) supplies natural gas to households and business in Victoria. Gas is transported from Longford in Victoria's east, via the Tasmanian gas pipeline, to and from Culcairn in Victoria's north, via the NSW transmission pipeline, and to and from Port Campbell in Victoria's west, via the SEA gas pipelines (AEMO 2020b).

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[2] *Investment and revenue are the annual averages for the current period using actual figures where available and forecast figures for the remaining years.*

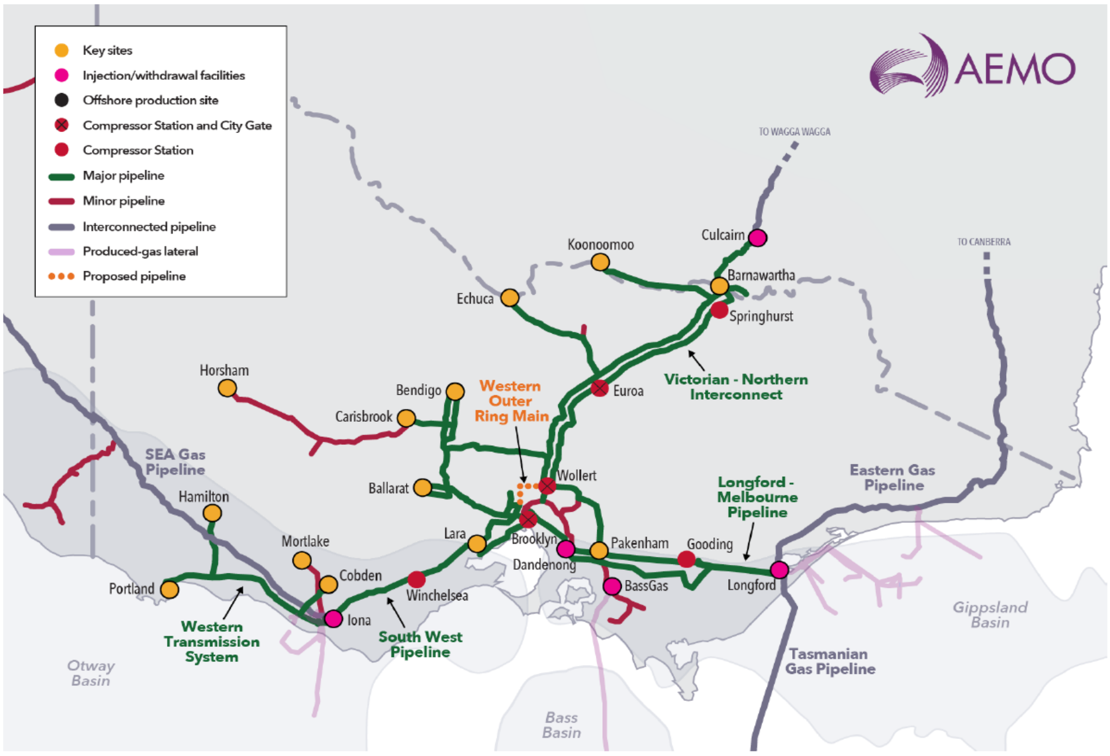

Figure 4: The Victorian Declared Transmission System (AEMO 2021b)

Gas storage

Victoria is reliant on storage capacity during peak winter periods. Victoria has two facilities for storing gas, the Iona Underground Gas Storage (UGS) in Port Campbell and the Dandenong LNG storage. The UGS reinjects gas into depleted gas reservoirs, which can be withdrawn out a later point in time. Victorian storage capacity, mainly Iona UGS, is needed to supply winter consumption. There is a risk that storage consumption will exceed the Iona UGS storage reservoir capacity if forecasted winter consumption is higher, forecasted production is lower or there is not additional supply from NSW (AEMO 2021b).

The declining Victorian production capacity during the outlook period is expected to reduce system resilience. Victoria relies on the Dandenong LNG storage facility to provide fast response peak shaving gas supply to alleviate threats to system security (AEMO 2021b). The Dandenong LNG storage facility provides the Victorian gas market with flexibility. It mainly provides gas buyers options to manage gas supply and demand during production outages or emergencies, and peak demand periods (AEMO 2020b).

Dandenong LNG plays a vital role in managing intra-day gas system pressures in Victoria. After it reached a high capacity in September 2020, storage levels fell to 443 terajoules on 31 December 2020 (see Figure 5). Capacity was at its overall lowest level, outside of winter since the beginning of the Declared Wholesale Gas Market (DWGM) in winter 2007. The decrease is driven by lower levels of contracted gas and slowing demand (AEMO 2021).

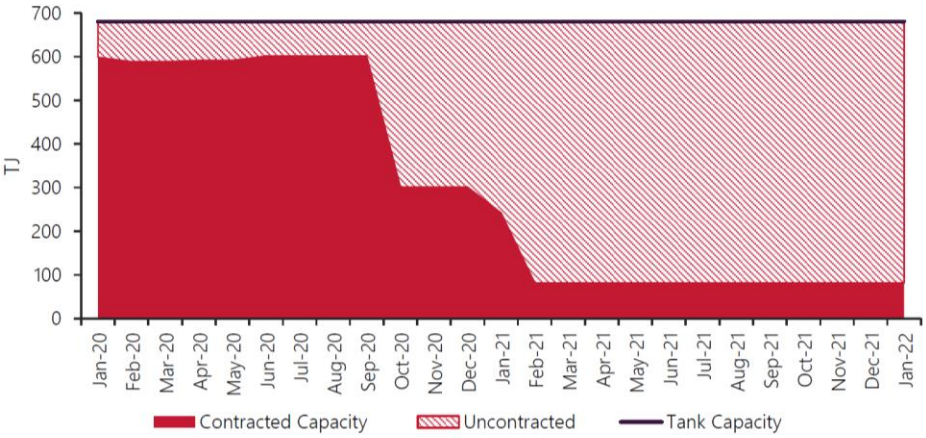

Figure 5: Dandenong contracted and uncontracted LNG (AEMO 2021)

Pipeline flows

As a gas exporter, Victoria has significant interconnections with other states. Although Victorian gas production slowed in 2020, Victorian net gas transfers to other states increased. Figure 6 shows an increased net gas flow to NSW of 5.3 PJ in the fourth quarter of 2020 compared to Q4 2019. The increased gas flows are caused by higher gas demand in NSW, which replaced gas supply from Queensland, and the Moomba – Sydney distribution pipeline to meet Queensland LNG export demand (AEMO 2021).

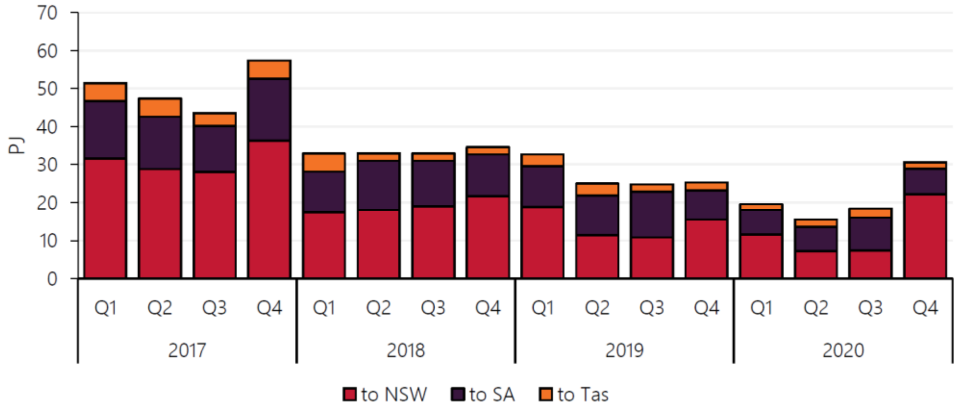

Figure 6: Victorian net gas transfers to other regions (AEMO 2021)

Gas end-use

Table 7 gives an overview of Victorian natural gas consumption, including LPG end-use by sector. The residential, manufacturing, electricity supply, and transport sectors accounted for nearly 90% of gas consumption in Victoria in 2018–19. Around 21% of Victorian natural gas consumption is needed for manufacturing mainly food, beverages, and tobacco, but also non-metallic mineral products, paper, and textiles. Natural gas is also used to meet peak electricity supply, with a share of 16.5%. The commercial and services sectors consume around 12.6% of natural gas. A small amount of natural gas is consumed in the mining sector, where natural gas is needed for oil and gas extraction. The transport sector consumes small quantities of LPG for road transport. The largest gas consumer in Victoria is the residential sector with a share of around 39%.

Table 7: Victorian gas consumption by sector in 2018-19 (DISER 2020a)

	Victorian gas consumption in 2018-2019	
	PJ	**Share**
Agriculture	1.0	0.3%
Mining (oil & gas extraction)	19.8	6.6%
Manufacturing	62.1	20.7%
Electricity (and water & waste) services	49.6	16.5%
Construction	1.8	0.6%
Commercial and services	37.9	12.6%
Transport	12.1	4.0%
Residential	116.2	38.7%
Total	**300.6**	**100%**

Due to its colder climate, homes in Victoria use much more residential gas than other states. Table 8 shows how Victorians use residential gas and how much of it is used in Australia. Natural gas is widely used in Australian homes for cooking, space, and water heating. Gas cooktops are commonplace in Victoria but consume only 2% of the states' residential gas use. Water heating consumes more natural gas than cooking, with a share of 24% of the Victorian residential gas use. Space heating is the most extensive use of natural gas, with 74% in Victoria. As a result, Victorians consume almost half of Australia's residential gas consumption only for heating. Where other states do not need heating, have single-room gas wall furnaces, or use electric heating, Victoria is highly dependent on inefficient gas ducted heating in all rooms (Grattan Institute 2020).

Table 8: Victorian residential gas use (Grattan Institute 2020)

	Cooking	Space heating	Water heating	Other appliances	Total
Share of VIC residential gas use, in %	2	74	24	0	100
Share of national residential gas use, in %	1	48	16	0	65

Gas prices

In recent years, wholesale gas prices have significantly risen in eastern Australia, including the Victorian and Queensland gas market. By 2018, wholesale gas prices rose from AUD $4 and AUD $6 per gigajoule to AUD $8 and AUD $10 per gigajoule for new gas contracts. Whereas the eastern gas prices have risen, the Western Australian gas price remained stable at around AUD $5 per gigajoule, see Figure 7 (Grattan Institute 2020).

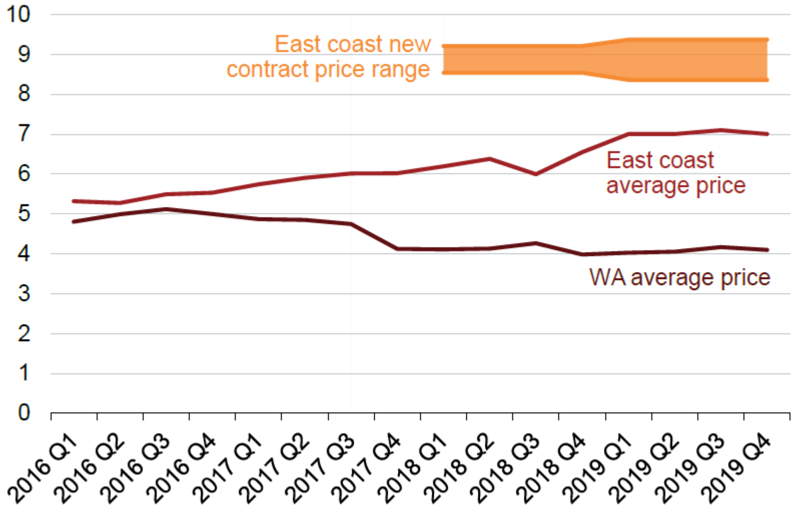

Figure 7: Comparison of east coast and WA average gas prices (Grattan Institute 2020)

Domestic gas prices were pushed by increased demand for Australian LNG from a larger and higher-priced international gas market, in particular Asia. Asian LNG prices soared to a new high of AUD $17.6 per gigajoule at the end of 2020 due to a colder than usual winter in the northern hemisphere, train outages at several major LNG facilities, and shipping disruptions. While prices on the east coast electricity and gas market have been highly correlated in recent years, they diverged in the second half of 2020, with gas prices rising but electricity prices remaining low (AEMO 2021). To meet the increased demand for natural gas, supply was increased by exploring more expensive gas sources, which further pushed prices in the east coast market (Grattan Institute 2020).

High prices on Australia's east coast, including Victoria, will increase risk and uncertainty for future energy costs and gas supply forecasts (CSIRO 2018). Lower international prices could suppress domestic exploration and development expenditure, reducing the longer-term gas supply outlook (AEMO 2020b).

2.1.2 Greenhouse gas emissions

The combustion of fossil fuels like oil, coal, and natural gas produces environmentally harmful greenhouse gases like carbon dioxide and methane.

Emissions by state

The *State and Territory Greenhouse Gas Inventories Report 2018* provides an overview of the latest available estimates of greenhouse gas emissions for Australia (DISER 2020b). Victoria is the third-largest contributor to Australia's total net emissions (19%), behind Queensland (32%) and NSW (25%) in 2018. Between 2005 and 2018, Victoria's total net emissions fell by 17.5% to 102.2 mega tonnes (Mt) (equivalent in 2018).[3] Victoria has the third-highest emission reduction results after Tasmania (111%) and South Australia (31.6%), which have more ambitious climate and renewable energy generation targets. Land-use changes and forestry have contributed to Tasmania achieving better

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[3] *2005 is the reference year for Victoria's emissions reduction target (Climate Change Act 2015)*

than net zero (negative). In Western Australia and the Northern Territory ,emissions have increased due to strong growth in mining and exports, and increased transport emissions (DISER 2020b). Victorian emissions reductions are partly due to increased renewable energy generation, as well as the closure of the coal-fired Hazelwood Power Station in March 2017 (DELWP 2018).

The *Victorian Greenhouse Gas Emissions Report 2018* states that the emissions of the energy sector, which comprises electricity generation (45.4%), direct combustion (17.4%), transport (22.9%), and fugitive emissions from fuels (3.8%), produced in total 89.5% of Victoria's total net emissions in 2018. Other emission contributors are agriculture (15.3%), industrial processes and product use (3.8%), and waste (2.5%). Land use, land-use change, and forestry (LULUCF) absorbed more emissions than it generated with, minus 11.2% of net emissions (DELWP 2018).

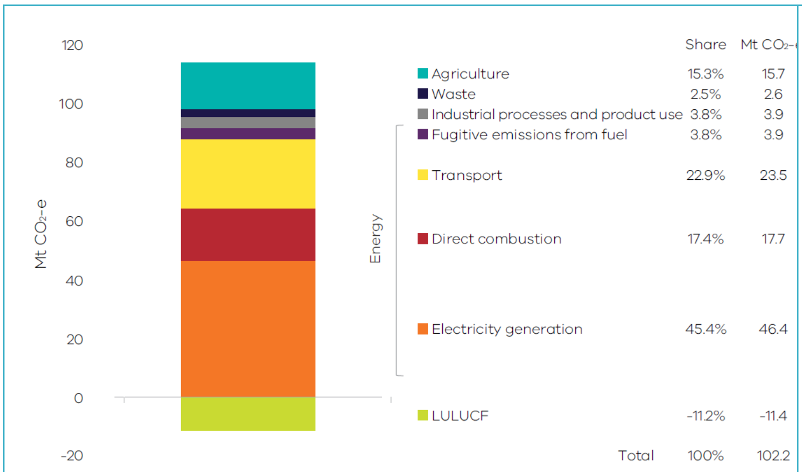

Figure 8: Victorian emissions by sector and energy sub-sector in 2018 (DELWP 2018)

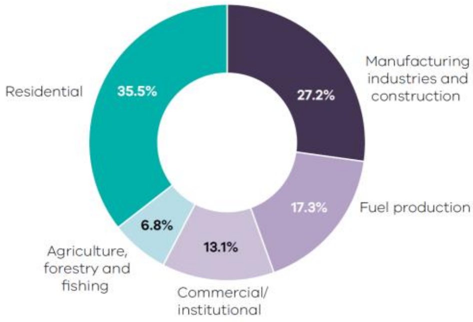

Figure 9: Direct combustion emissions by end-use in 2018 (DELWP 2018)

Natural gas emissions

Natural gas emissions are only reported by the Department of Industry, Science, Energy and Resources (DISER) and the Department of Environment, Land, Water and Planning (DELWP) in the context of direct combustion and fugitive emissions.

Fugitive emissions comprise greenhouse gas emissions from the extraction and distribution of coal, oil, and natural gas. In 2018, total emissions from fugitive fuels were 54.4 Mt of carbon dioxide equivalent in Australia with a Victorian share of 7.1% (or 3.9 Mt of carbon dioxide equivalent) (DISER 2020b).

Whereas natural gas has a small fraction of Victoria's electricity generation, gas is the primary fuel used for direct combustion, representing 62% of the total fuels used in 2018 (see Figure 9). Direct combustion emissions arise from burning fossil fuels for generating heat, steam, or pressure for major industrial operations and burning gas for household heating, hot water, and cooking. In 2018, Victoria consumed a total of 237 PJ of natural gas in direct combustion activities, with the highest consumption in residential activities (38.7%), followed by manufacturing (20.7%) and commercial (12.6%) activities. Almost 61% of fugitive emissions in Victoria arise from leakage of gases during the exploration, production, transmission, storage, and distribution of natural gas. Most of Victoria's remaining fugitive emissions relate to flaring and venting associated with oil and natural gas production and processing (DELWP 2018).

About 19% of Australia's total greenhouse gas emissions come from natural gas (see Figure 10). That is estimated to consist of about 14% of total emissions from burning the gas and approximately a further 5% from fugitive emissions. While natural gas combustion causes fewer emissions than coal, the amount of fugitive emissions is likely underestimated, and the negative climate effect of natural gas might be even more significant (Grattan Institute 2019).

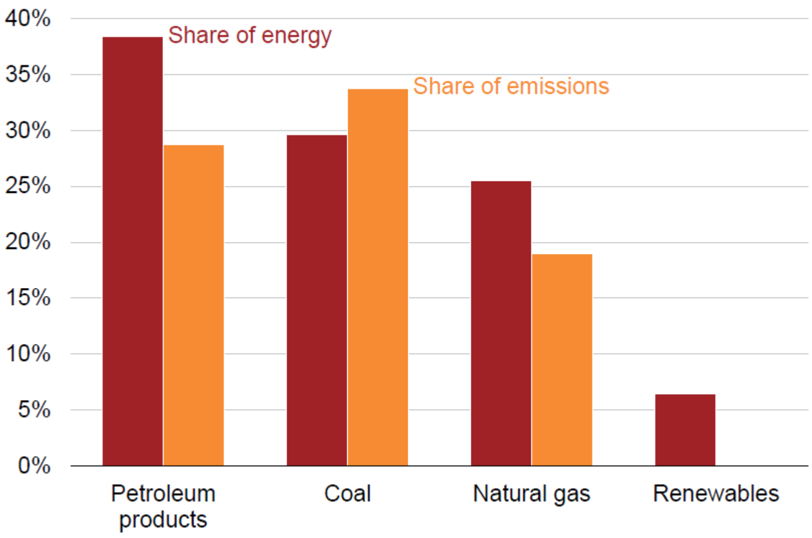

Figure 10: Share of energy consumed and share of greenhouse gas emissions (Grattan Institute 2019)

2.2 Decarbonisation technologies

This section gives an overview of the three transformational technologies that may be able to be deployed to decarbonise the Victorian gas infrastructure. It also explores the risks and benefits of each technology.

2.2.1 Need for decarbonisation

Available modelling work in this space provides global and Australia-wide analysis. No Victoria-specific work has been identified.

Economic recovery with decarbonisation

The COVID-19 pandemic has caused great economic impacts globally. Many governments are creating stimulus packages to boost their economies and recognise decarbonisation as an opportunity to create new jobs and tackle emissions reduction.

A 2020 McKinsey survey finds government spending on renewable energy like wind, solar, and bioenergy and energy efficiency (including industrial energy efficiency and smart grid), creates more jobs than spending on fossil fuels like oil, coal, and natural gas. A balanced low carbon stimulus portfolio of push and pull factors can also produce significant additional economic and environmental benefits. For example, on the regulation side in some jurisdictions, industrial emitters may be required to adopt carbon capture and storage (CCS) technologies (push). Therefore, funding in CCS infrastructure in industrial hubs is required (pull) (McKinsey & Company 2020). The survey provides a global overview. The conclusions are based on existing scientific studies released before the pandemic. There are no conclusions for the infrastructure of natural gas or zero emission gas.

The Australian think-tank Beyond Zero Emissions refers to McKinsey’s study and delivers detailed conclusions for Australia. *The Million Jobs Plan* describes how Australian sectors such as renewable energy, buildings, transport, and manufacturing could generate more than one million new jobs, reversing the losses from COVID-19. It says Australia could quickly become a world leader in the production of hydrogen, ammonia, steel, aluminium, and other metals using 100% renewable energy, creating 230,000 jobs. The analysis was carried out using a macro-econometric model (Beyond Zero Emission 2020). No further information on the methodology or the analysis approach is provided.

Another Australian think-tank, the Climate Council, comes to a similar conclusion. Its *Clean Jobs Plan*, modelled by Alphabeta, offers 12 policy opportunities to stimulate a low-emission economy and create 76,000 jobs over the next three years for resilient long-term recovery and zero emissions in Australia. In Victoria, the plan would create an estimated 15,000 – 20,000 jobs in the short-term. Major job creators include installing utility-scale renewable energy (3,000 – 4,000) and organic waste management (2,000 – 2,500). It finds green hydrogen and electric vehicle (EV) charging networks have an insignificant influence on job creation in the short-term. Alphabeta applied a detailed methodology including the review of existing international policies, assessed against key selection criteria, and evaluated by experts from both policy and industry. Detailed economic analysis using data from the Australian Bureau of Statistics was conducted to estimate potential jobs impacts (Climate Council 2020a).

Global climate risk natural gas

The most compelling reason to decarbonise energy and gas infrastructure is the climate risks from carbon and methane emissions. The challenge for the gas industry is to restructure itself for an emission-free energy future.

The International Energy Agency (IEA) provides a yearly update in its *World Energy Outlook*. Detailed scenario analysis provides an outlook of future energy use, emissions and their implications for investment and policy. The report finds that while natural gas has a better global outlook than oil and coal, there remain “crucial” uncertainties around the methane emissions from gas technologies. It finds methane abatement can be reached via alternative gases such as biomethane and low carbon hydrogen (see detailed description in section 2.2.3 Hydrogen) and technologies like carbon capture, utilisation and storage (CCUS), which need rapid innovation and deployment in the 2020s (IEA 2020c). The IEA is an autonomous intergovernmental organisation established in the framework of the OECD.

The Institute for Energy Studies at the University of Oxford highlights the need for the gas community to reach the COP21 targets. Therefore, the gas industry needs to develop decarbonisation technologies including size and timing of developing commercial-scale projects for biogas, biomethane, and hydrogen from power to gas (electrolysis). It finds that, since there are uncertainties around fugitive emissions for the production and transport of natural gas, pathways that extend the use - like reforming methane to produce hydrogen - must be avoided.

To preserve gas decarbonisation options and enable a future low carbon gas sector, a 'regulatory revolution' is necessary, which needs government funding and substantial corporate investment (University of Oxford 2019). The report assumes that the future gas industry will maintain current natural gas demand levels. Alternative pathways like electrification are regarded as unsatisfactory because of the stranding risk of substantial gas network assets. The Oxford Institute for Energy Studies Natural Gas Research Programme is sponsored by private sector organisations including members of the gas industry. The report is peer reviewed.

Meanwhile, not-for-profit group the Global Energy Monitor describes the risks of the global LNG infrastructure becoming underutilised or stranded assets before their end of life of 30 to 40 years. One reason is the pandemic-related decline of global oil and gas demand could lead to a high default rate on planned LNG export terminal projects. It says another reason natural gas should only be viewed as a "bridge fuel" is its impact on climate change, and that fugitive emissions have been underestimated. It suggests extending fossil combustion and switching from coal to gas does not offer a valuable strategy to achieve zero emissions. Emissions from LNG, including recent estimates of methane leakage throughout the system, are 29% lower to 16% higher than coal-fired power (Global Energy Monitor 2020). The correct estimation of fugitive emissions remains questionable. The Global Energy Monitor receives funding from primarily environmental organisations. Data is attributed to a source and transparent, and conclusions focus on the achievement of ecological and social goals.

Local climate risk natural gas

Australian think-tank ClimateWorks discusses the challenges and opportunities in reshaping transport, energy, water, communications, and waste infrastructure for a net zero emissions future. Combined, these sectors generate around 70% of Australia’s greenhouse gas emissions. Emissions from natural gas contribute a share of 12.7%, mainly caused by operating gas networks and fugitive emissions. The contribution of fugitive emissions is uncertain (ClimateWorks 2020b).

ClimateWorks suggest emissions reduction strategies should be developed that do not attempt to predict the future but offer greater certainty, as well as minimise risks in public and private investment decisions. For example, if natural gas is replaced by electricity in the residential sector, the value of gas networks’ is reduced and run the risk of becoming stranded assets, unless they are adapted to supply zero emission gas. To reduce these risks, a broad range of scenarios should be explored (ClimateWorks 2020b).

The Climate Council’s *Passing Gas* report gives a detailed overview of Australia's gas market. The report concludes that natural gas emissions are under-reported in Australia. Further, extracting and burning natural gas will escalate Australia’s climate risk and miss global climate change targets. Australia’s dependency on export and decreasing international gas market prices shows Australia is further exposed to job losses and energy price volatility. The report finds Australia can transition to a 100% renewable electricity supply supported by a mix of battery storage and demand-side solutions (Climate Council 2020b) and that new gas infrastructure is not needed. However, solutions for hard-to-abate gas industries and consumers, the risks of stranded assets, nor re-purposing the gas networks with zero emission fuels are not discussed.

The Grattan Institute gives an overview of natural gas production, prices, policies, and possible net zero emissions pathways in Australia, including specific recommendations for action. The Grattan Institute discuss multiple factors that could be included in future energy scenarios or pathways to lower emissions. For example, in the Grattan scenario, natural gas as a “backstop” is not a baseload power source but a flexible power source during demand peaks and persistent periods of low wind and sun. Also, it states the use of natural gas for residential heating must decline, particularly in Victoria. Grattan acknowledges that favouring electricity over gas is cost intensive through the inclusion of new appliance costs and connection upgrades. Therefore, low-emissions gas supply like biomethane and hydrogen need to be developed and applied in the long-term, requiring clear policy signals and commitment. The report concludes the priority now is to better understand the technical and economic viability of low-emissions gas substitutes (Grattan Institute 2020).

2.2.2 Australian decarbonisation pathways

Some research has been done on decarbonisation pathways for Australian gas infrastructure. Most of the work focuses on cost benefits analysis of different scenarios in 2050. Work funded by Energy Networks Australia, the peak body for Australia’s gas distribution networks is considered to present results in the interests of the gas sector. However, the pathways deliver helpful insights and will be further analysed in the section Analysis of decarbonisation pathways.

ClimateWorks’ *Decarbonisation Futures* report (2020) models least-cost and feasible decarbonisation pathways for Australia. It finds that Australia can achieve net zero emissions by 2050 and live within its recommended carbon budget, using technologies that exist today, while maintaining economic prosperity. Decarbonisation is based on an ambitious program of energy efficiency, low carbon electricity, electrification, fuel switching and reducing non-energy emissions in industry and agriculture. Natural gas is replaced, eliminated, or emissions are captured.

For example, electricity generation switches to low carbon energy sources such as renewable energy technologies or CCS. For residential use, natural gas switches to a decarbonised electricity supply. For the transport sector, electric batteries and hydrogen fuel-cells for cars and light commercial vehicles are used. However, natural gas is used in place of oil extensively for road freight. Emissions from natural gas use in industry and agriculture are captured via CCS or offset with carbon forestry (ClimateWorks Australia 2020a).

Energy Networks Australia’s (ENA) *Gas Vision 2050* also provides an overview of the current gas industry, market, and technologies. The ENA presents a vision for net zero gas use in homes, cities, industrial uses, and power generation. Options to reduce natural gas emissions include energy efficiency, decarbonisation of fuel (including hydrogen and biomethane), electrification of heat and carbon offsets. It includes analysis by Frontier Economics which includes a scenario analysis of decarbonised fuel options and their projected costs. It finds net zero emissions can be reached with hydrogen at half the cost of electrification when Australia’s existing gas infrastructure and natural gas resources are used (Energy Networks Australia 2019).

ENA engaged both Frontier Economics and Deloitte Access Economics to model net zero emissions scenarios plus projected costs. The Frontier Economics modelling includes electrification, renewable fuels with green hydrogen, and zero-carbon fuel with blue hydrogen. It finds each of the three scenarios can reach net zero emissions but will entail additional costs. The modelling finds renewable fuels and the zero-carbon fuels scenarios have lower costs than the electrification scenario, suggesting that there is value in continuing to make use of Australia’s gas network and resources (Frontier Economics 2020b).

Deloitte Access Economics analyses the decarbonisation of gas distribution networks using biogas, hydrogen, and CSS to deliver zero carbon energy. The analysis suggests a variety of decarbonised gas options that are likely to be cost competitive with electrification over the long-term (Deloitte Access Economics 2017).

The Australian Gas Infrastructure Group (AGIG) also worked with Deloitte to analyse converting to hydrogen as Victoria’s decarbonisation pathway. Two scenarios relevant only to the energy sector are compared: full electrification and the hydrogen conversion case, in the energy sector only. The cost analysis concludes that the use of hydrogen is 40% less expensive than the complete electrification of the gas infrastructure for energy generation in Victoria (AGIG 2018).

2.2.3 Hydrogen

Many of the identified publications in this literature review deal with hydrogen only. Therefore, technical details are briefly explained to better understand hydrogen applications.

Technical Details

Hydrogen (H2) is the most common chemical in the universe. Hydrogen is a colourless, odorless, highly combustible gas. If hydrogen burns with oxygen, it forms water (H_2O) (J.P. Morgan 2020).

Hydrogen use

Hydrogen can be used as both an energy supply and an industrial feedstock for chemical production, and could contribute to greenhouse gas emission reduction, depending on how it is produced. The use of hydrogen rather than natural gas depends on the (mainly costs) competitiveness of alternative technologies (CSIRO 2018).

Hydrogen production

Hydrogen can be produced from water in three different processes, see Figure 11.

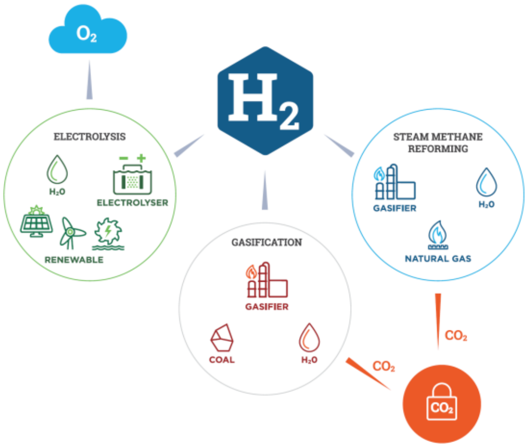

Figure 11: Production pathways for clean hydrogen (COAG Energy Council 2019)

Figure 11 and Table 9 give an overview of hydrogen production methods and their carbon credentials. The colour attributes help to describe the emission intensity of the used input fuels. However, hydrogen is a colourless and odourless gas.

Table 9: Production methods of hydrogen and its attributed colours (J.P. Morgan 2020)

Hydrogen 'colour'	Production method	Input fuel to produce hydrogen	Carbon credentials
Brown	Coal gasification (CG)	Brown or black coal	Very high process emission, very high total emissions
Grey	Steam methane reforming (SMR)	Natural gas	High process emission, high total emissions
Blue/ clean	CG/SMR + CCS	Coal or natural gas with carbon offsets	Moderate process emission, moderate total emissions
Turquoise/ clean	Molten Metal Pyrolysis of Methane	Natural gas	Low/zero process emission, moderate to high total emissions
Green/ clean/ renewable	Electrolysis of water	Renewable energy (wind, solar, hydro)	Zero process emission, moderate total emissions

A) Brown Hydrogen (using coal gasification): Gasification is a thermochemical process using brown or black coal to produce hydrogen. The fossil fuel coal produces CO_2 emissions that are commonly not captured and stored via CCS. If hydrogen is produced by coal, it is often referred to as “brown hydrogen” (J.P. Morgan 2020) (Deloitte 2019).

Currently, gasification with SMR is the most common process to produce hydrogen. Gasification already has a high technical maturity and produces hydrogen at low cost. However, future cost reductions are limited as there is little scope for further process efficiency (CSIRO 2018). Producing brown hydrogen is also emissions intensive and requires substantial CCS capacities to produce emission-free hydrogen, which must be factored when considering overall emission reduction targets (J.P. Morgan 2020).

B) Grey or Blue Hydrogen (using steam methane reforming): SMR is a thermochemical process using natural gas and pressured steam to produce a blend of CO_2 and hydrogen. CO_2 emissions must be captured and stored via CCS for the hydrogen to be considered low or zero emissions. If hydrogen is produced by natural gas without CCS, it is referred as “grey hydrogen”. If it is produced using natural gas and CCS, it is often referred as “blue hydrogen” (J.P. Morgan 2020) (Deloitte 2019). Blue hydrogen using fossil fuels with carbon offsets with CCS is also sometimes referred to as “clean hydrogen”, “low emission hydrogen” or “CCS hydrogen”.

Currently, SMR is, along with gasification, the most common process used to produce hydrogen. SMR already has a high technical maturity and produces hydrogen at low cost. However, future cost reductions are limited as there is little scope to improve process efficiency (CSIRO 2018). Grey hydrogen (without CCS) is a highly polluting production method that conflicts with emission reduction targets. Blue hydrogen that uses CCS still results in some emissions, but these are considered negligible. Blue hydrogen using CCS may be a possible pathway to replace natural gas, using existing gas infrastructure while producing only moderate emissions but there are still significant uncertainties about the economic feasibility of this at scale. (J.P. Morgan 2020).

The Hydrogen Council also lists Autothermal Reforming (ATR) which uses oxygen and natural gas to produce hydrogen. This process can more easily capture carbon emissions but remains unproven at scale (Hydrogen Council 2020).

C) Green Hydrogen (using electrolysis): The electrolysis process extracts hydrogen from water using electricity. If renewable electricity like wind or solar energy is used, hydrogen is often referred to as “green hydrogen” (J.P. Morgan 2020) or “renewable hydrogen” (COAG Energy Council 2019). Using renewable electricity, electrolysis produces no emissions. However, if fossil fuel-based electricity is used (such as in Victoria), the hydrogen is technically referred to as blue or brown hydrogen. In order to qualify as green hydrogen, equivalent emissions for the electricity generated must be captured and stored via CCS (J.P. Morgan 2020). As with blue hydrogen, green hydrogen is sometimes referred to as "clean hydrogen" or "low-emission hydrogen".

The most promising production methods include the Polymer Electrolyte Membrane (PEM) and the Alkaline Electrolysis (AE). However, electrolysis is still an emerging technology, characterised by low maturity, and process inefficiencies with high energy requirements (CSIRO 2018). Currently, it is very costly to produce hydrogen with electrolysis. However, depending on the investment level in research and development, electrolysis has the highest efficiency growth potential to produce low cost, zero emissions hydrogen in the future. Green hydrogen may be a possible pathway to replace natural gas, using upgraded existing gas infrastructure without causing emissions (J.P. Morgan 2020).

Hydrogen storage & transport

Hydrogen can be stored as both a gas and a liquid. Depending on its condition, hydrogen can be transported by pipeline, truck, ship, or rail (CSIRO 2018):

A) Compression: Hydrogen gas can be stored and compressed at higher pressures to increase the volume. That allows large-scale underground storage like salt caverns and "line packing" in gas pipelines. Compression represents the most attractive hydrogen storage option because of its lower cost than liquefaction and maximises availability of space.

B) Liquefaction: Hydrogen can be pressured and cooled to minus 253˚C to be transported in a liquid state by trucks, ships, or rail. Because liquefaction has higher costs than compression, it is more financially viable when there are stringent space limitations.

C) Chemical: Hydrogen can be used as chemical storage to carry molecules such as ammonia, metal hydrides, and toluene. Relevant hydrogen separation technologies are currently being developed and are not yet mature enough to gain a meaningful assessment of cost.

Environmental, social, and economic assessments

Some of the reviewed literature assesses the environmental, social, and/or economic impacts of hydrogen production. The following section summarises and compares key findings.

Environmental impacts

Depending on the hydrogen production method, different input resources are required, each with unique lifecycle and climate impacts.

Table 10 gives an overview of the estimated resources needed for the three different forms of hydrogen production in 2050. In summary:

- Around 31,700 to 63,600 gigawatt hours (GWh) of renewable energy in electrolysis are needed to produce 100 PJ or 1 kg of hydrogen. CCS is not required and therefore green hydrogen has a low emissions profile. However higher water amounts are needed (10.8 to 19 mega litre (ML)).
- Hydrogen using natural gas (SMR) needs slightly less water but produces emissions of around 8 Mt CO_2 per 100 PJ produced hydrogen which must be captured through CCS.

Hydrogen produced through gasification using brown coal requires almost double the amount of carbon capture capacity with around 16 Mt CO_2 per 100 PJ. Brown coal has a lower heating value than black coal, meaning more brown coal is needed to produce energy. Because brown coal has a high moisture content, little water is needed in the gasification process (Deloitte Access Economics 2017). KPMG only considers Victoria's local brown coal resources. Therefore, conversion properties reflect average properties of Victorian brown coal (KPMG 2018). In Victoria, there are significant brown coal reserves in the Gippsland region and a developed offshore reservoir with known subsurface geology suitable for CCS (CSIRO 2018).

Table 10: Overview of resource demand for 100 PJ hydrogen (Deloitte Access Economics 2017) or for 1 kg of hydrogen (KPMG 2018)

Resource demand	Source	Electrolysis	Gasification		SMR
		Renewables	brown coal	black coal	Natural gas
Energy demand in GWh	DAE	31,731	-	-	-
	KPMG	63,600	-	-	-
Coal in Mt	DAE	-	16	63	-
	KPMG	-	14.3	-	-
Natural gas in PJ	DAE	-	-	-	130
	KPMG	-	-	-	207.7
Required CCS capacity in Mt	DAE	0	15.5	15.7	8
Water in ML	DAE	10.8	2-3.1	9-10.3	10.6
	KPMG	19.04	14.25		23.2

Table 11 compares carbon emissions caused by the different forms of hydrogen production.

It is worth noting that different information sources use different input factors, resulting in different emission rates. Nevertheless, a general conclusion and ranking has been derived.

Table 11: Comparison of emissions for hydrogen production in kg CO_2-e/kg hydrogen

Emissions in kg CO_2-e/kg hydrogen	Electrolysis		Gasification (brown & black coal)		SMR	
	Australian grid electricity	100% renewable electricity	no CCS	CCS – best case	no CCS	CCS – best case
(COAG Energy Council 2019)	40.5	0	12.7 – 16.8	0.71	8.5	0.76
(KPMG 2018)	-	0	28.23	-	9.26	-
(J.P. Morgan 2020)	-	0.6 – 4.5[4]	7.1 – 16.3	1.3 – 4.6	5.8 –8.1	0.6 – 3.8

The Hydrogen Council predicts low emissions hydrogen would reduce global emissions by roughly 6 giga tonnes (Gt) by 2050 compared to today's technologies and contribute 20% of the required CO_2 abatement by 2050 (Hydrogen Council 2017).

The COAG Energy Council compares the emissions of each hydrogen process, concluding that gasification produces higher emissions than SMR. In total, replacing Australia's grid electricity with electricity from clean hydrogen avoids 15 kg CO_2 emissions per kilogram of hydrogen used. Data is referenced to CSIRO (COAG Energy Council 2019).

KPMG reached the same conclusion: renewable electrolysis produces no emissions, emissions from gasification are about three times higher than from SMR. KPMG only consider brown coal as an input fuel for the gasification production process because of Victoria's large brown coal availability (KPMG 2018).

A 2020 study by J.P. Morgan differentiates between process emissions, supply chain emissions and total life cycle emissions. Table 11 uses total life cycle emissions and also finds gasification produces higher emissions than SMR. However, the study does not specify what energy content for hydrogen or other input factors have been used. Emissions data is referenced to several other sources[5] (J.P. Morgan 2020).

It finds to produce clean hydrogen larger CCS capacities are required to capture the higher emissions of gasification than SMR. Electrolysis using renewables requires no CCS.

Social assessment

According to the Hydrogen Council, the large-scale use of low emission hydrogen would create significant benefits for the energy system, the environment, and businesses worldwide. It says hydrogen can decrease the need to transport fossil fuels across the world and boost energy security. The value creation in a hydrogen economy would create more employment and domestic value than fossil fuels' value chains (Hydrogen Council 2017).

For example, the Australian National Hydrogen Strategy (COAG Energy Council 2019), says the Australian hydrogen industry could generate about 7,600 jobs and AUD $11 billion in GDP in 2050 with exported hydrogen. If global markets develop fast, estimates rise to an additional 17,000 jobs and AUD $26 billion in GDP in 2050 (COAG Energy Council 2019).

The direct Australian economic contribution of low emission hydrogen production for export, including employee wages and gross operating surplus of hydrogen producers and exporters, is estimated to be AUD $417 million and 700 FTE jobs in the medium scenario in 2030. In the high scenario, the employment is comparable to the numbers employed in the LNG industry and its direct supply chain. Through the direct employment associated with hydrogen production facilities, hydrogen production for export may benefit regional communities, Traditional Owners, and the broader Australian community (ACIL Allen Consulting 2018).

Economic assessment

Table 12 compares the cost for each process of hydrogen production. Different sources use different parameters, which result in different costs.

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[4] *Total life cycle emissions consider emissions in renewable electrolysis, which typically arise in the manufacturing stage of the renewable generation technologies, including process energy requirements and the embodied emissions in raw materials.*

[5] *A greener gas grid, White Paper Jul'17, Imperial College London*

Table 12: Comparison of levelised cost of hydrogen in $/ GJ in 2030/ 2050

Levelised cost of hydrogen	Electrolysis	Gasification with CCS	SM with CCS
(Deloitte Access Economics 2017) 2050 scenario	$25.43 /MWh	$26.32 – $30.13 /MWh	$20.93 /MWh
(CSIRO 2018) 2030 scenario	$2.29 – $2.79 /kg (PEM) $2.54 – $3.1 /kg (AE)	$2.02 – $2.47 /kg (black) $2.14 – $2.74 /kg (brown)	$1.88 – $2.30 $/kg

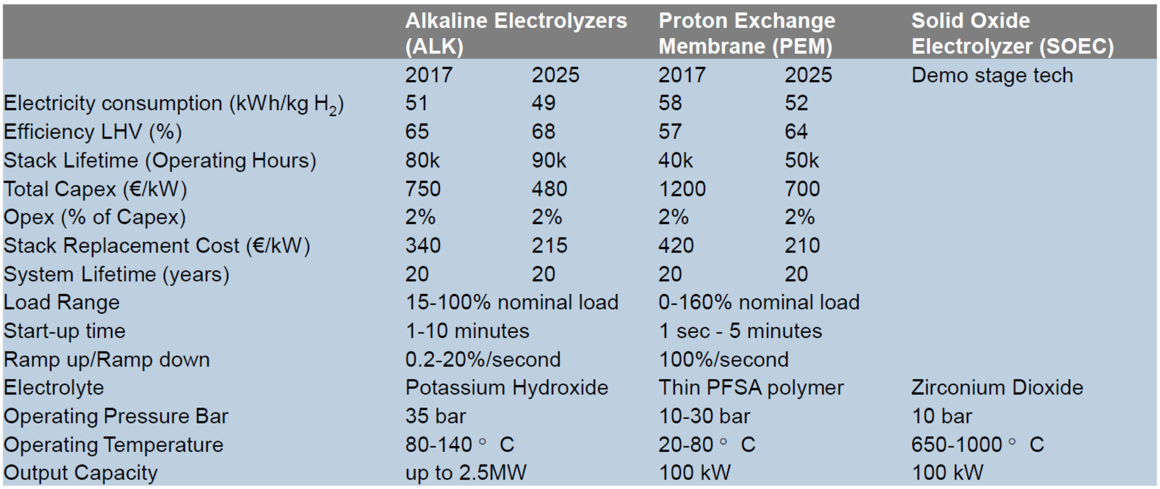
The CSIRO provide a detailed summary of the parameters used in the analysis. Input parameters can be:

- Price for energy input (price for one tonne of brown or black coal or one petajoule of natural gas)
- Capacity factor and plant size
- Capital costs
- Efficiency of technology.

Green hydrogen produced via electrolysis has the highest production costs in comparison to gasification and SMR.

In comparison to the base case in 2018, it is expected that the cost of Proton Exchange Membrane (PEM) and Alkaline Electrolysers (ALK) (electrolysis) could be reduced to AUD $2.29 – $2.79 per kg and AUD $2.54 – $3.10 per kg, respectively, in 2030. Should SMR and gasification projects also be developed, given they are mature technologies, incremental improvements could be achieved (SMR: AUD $1.88 – $2.30/kg, gasification: AUD $2.02 – AUD $2.47/kg), assuming energy input prices remain constant and that the points of hydrogen generation and CO_2 sequestration are reasonably proximate (CSIRO 2018).

Figure 12 compares different types of electrolyser technologies in more detail. The overview offers a detailed analysis of input factors. Sources were mainly used from the International Renewable Energy Agency (IRENA) but also the Imperial College London. Compared to the PEM, the ALK seems to be the hydrogen technology with lower capital expenditure (J.P. Morgan 2020).



	Alkaline Electrolyzers (ALK)		Proton Exchange Membrane (PEM)		Solid Oxide Electrolyzer (SOEC)
	2017	2025	2017	2025	Demo stage tech
Electricity consumption (kWh/kg H_2)	51	49	58	52	
Efficiency LHV (%)	65	68	57	64	
Stack Lifetime (Operating Hours)	80k	90k	40k	50k	
Total Capex (€/kW)	750	480	1200	700	
Opex (% of Capex)	2%	2%	2%	2%	
Stack Replacement Cost (€/kW)	340	215	420	210	
System Lifetime (years)	20	20	20	20	
Load Range	15-100% nominal load		0-160% nominal load		
Start-up time	1-10 minutes		1 sec - 5 minutes		
Ramp up/Ramp down	0.2-20%/second		100%/second		
Electrolyte	Potassium Hydroxide		Thin PFSA polymer		Zirconium Dioxide
Operating Pressure Bar	35 bar		10-30 bar		10 bar
Operating Temperature	80-140 ° C		20-80 ° C		650-1000 ° C
Output Capacity	up to 2.5MW		100 kW		100 kW

Figure 12: hydrogen - electrolyser technical properties (J.P. Morgan 2020)

Literature overview

The following section presents hydrogen strategies, roadmaps, and current research that have been identified as relevant for the literature review.

Hydrogen strategies and roadmaps

There are several hydrogen strategies and roadmaps on international, national, and regional levels.

The Future Fuels CRC, a research body funded largely by the Australian Gas Pipelines Association, summarises 19 global hydrogen strategies. It shows how nations, regions, and industries are exploring opportunities to become involved in the emerging hydrogen industry. In particular, Japan, the Republic of Korea, China, Germany, Britain, the European Union, and New Zealand all have detailed roadmaps to develop a clean hydrogen strategy (Future Fuels CRC 2019).

At an international level, the IEA's *The Future of Hydrogen* report (IEA 2019) finds that clean (blue and green) hydrogen is currently experiencing unprecedented political and business momentum, with the number of policies and projects around the world expanding rapidly. The report summarises current global hydrogen production, storage, and transport potential. The analysis is based on scientific sources and received feedback from other experts within the IEA. The report concludes that now is the time to scale up technologies and bring down costs to allow clean hydrogen to become widely used. Policy recommendations for governments and industry in key value chains are provided (IEA 2019):

- Build clean hydrogen hubs in coastal industrial areas
- Use existing gas infrastructure
- Make fuel cell vehicles more competitive
- Kick-start international hydrogen trade.

While Australia is referred to as a competitive hydrogen location, it is difficult to derive any targeted recommendations for Victoria's decarbonisation pathways.

The Hydrogen Council presents a global vision of hydrogen's long-term potential and a detailed roadmap for its deployment from 2030 until 2050. The approach delivers deep decarbonisation of transport, industry, and buildings and enables a renewable energy production and distribution system (Hydrogen Council 2017). The roadmap is developed with consulting firm McKinsey & Co. It includes a theoretical approach and the calculation of potential hydrogen applications but no further quantification of pathways.

In an updated report, the Hydrogen Council (2020) examined the costs of hydrogen, predicting decreased costs of up to 50% by 2030 for a wide range of applications and making hydrogen competitive with other low carbon alternatives or conventional options. The study is based on industry data and reviewed by independent experts from energy-intensive manufacturers, the oil and gas industry. Analytical support is provided by McKinsey (Hydrogen Council 2020). The roadmap will be used to inform the section Analysis of decarbonisation pathways (2.3).

At a national level, the CSIRO has also designed a roadmap for the development of a clean (blue and green) hydrogen industry in Australia. A timeframe from 2020 until 2030 demonstrates seven key investment priorities. The expected cost reductions of hydrogen supply and target markets' progression are based on when and how clean hydrogen could be commercially competitive with alternative technologies. The roadmap will help inform the next series of investments amongst various stakeholder groups like industry, government, and research to continue to scale up the hydrogen in a coordinated manner (CSIRO 2018). The roadmap will be used to inform the section Analysis of decarbonisation pathways (2.3).

Australia's *National Hydrogen Strategy,* developed by Deloitte for the COAG Energy Council*,* also sets out a vision for a clean, innovative, safe, and competitive hydrogen industry by 2030. It finds Australia can leverage a competitive advantage to produce green hydrogen from electrolysis and meet the global demand for emissions-free transport, utilities, electricity, heat generation, and industrial feedstock (COAG Energy Council 2019). The strategy will be used to inform section Analysis of decarbonisation pathways (2.3).

At the regional level, the Victorian Government is also supporting the emerging green (renewable) hydrogen industry. *The Renewable Hydrogen Industry Development Plan* sets a vision for developing a renewable hydrogen sector in Victoria. The plan sets out how Victorian can establish fully integrated supply chains to:

- build the foundation and policy environment for renewable hydrogen
- connect the economy for sector coupling of hydrogen hubs, supply chains capabilities, gas and electricity networks, export functions, transport sector, and industrial use
- lead the way and navigate a path to net zero emission with renewable hydrogen for economic growth (DELWP 2020).

Export potential

The National Hydrogen Strategy (COAG Energy Council 2019) analyses Australia's position in the hydrogen export market against potential competitors and the share of this demand that Australia could potentially capture. It finds if Australia were to secure the same global market share percentage as Australia has today for LNG, then the hydrogen sector could produce an increase to Australian GDP of up to AUD $26 billion on a Net Present Value (NPV) basis and 16,900 jobs by 2050 (Deloitte 2019). The scenarios will be used to inform the section Analysis of decarbonisation pathways (2.3).

ACIL Allen Consulting, who received funds from the Australian Renewable Energy Agency (ARENA) for this work, provides results for a scenario modelling hydrogen demand in four Asian countries with similar markets and policies for exports of Australian hydrogen in 2040: China, Japan, Republic Korea, and Singapore. It finds Australia is in a good competitive position to become a low carbon hydrogen exporter compared other countries such as Norway, Iceland, USA, and the Middle East. This is because Australia's greater ability to supply blue and green hydrogen from a large range of energy sources, experience in large-scale energy infrastructure construction, well established energy trading relationship and proximity to Asian markets. The report focuses on the potential projected (not forecasted) demand for low emission hydrogen for energy use. However, it finds green hydrogen as a chemical feedstock is unlikely to see wide-spread adoption until 2040. The analysis of low carbon hydrogen demand represents three possible future worlds with low, medium, and high hydrogen uptake rates in each. Assumptions are mainly based on climate change and global warming commitments, adoption of hydrogen technologies, and alternative fuel prices, but also population, labour market, and productivity growth (ACIL Allen Consulting 2018).

Victoria – regional priorities

Geoscience Australia (2019) provides maps that show regions with high potential for future green and blue hydrogen production and CCS under different scenarios in Australia. Using geospatial analysis, the report considers extensive regions with the base elements and infrastructure to support large-scale renewable hydrogen (green) and CCS hydrogen (blue). Most coastal areas have a high potential for green hydrogen production from electrolysis. The supply of water and the availability of electrical and port infrastructure makes these favourable areas for green hydrogen production (Geoscience Australia 2019). The maps within the report will inform our Analysis of decarbonisation (2.3).

A technical study by Arup Australia, which was developed for COAG Energy Council's *National Hydrogen Strategy*, builds on Geoscience's findings. The study identifies suitable locations for hydrogen export hubs, supply chain infrastructure to support these hubs, and criteria to determine the feasibility of hydrogen precincts, cities, and regions in Australia. The approach is based on desktop research and stakeholder consultation. The criteria to assess the viability and suitability of the domestic and export hydrogen hubs include:

- environmental, economic, and social considerations
- availability of water, land, and skilled workers
- availability of existing electricity and gas infrastructure, site access like road and rail infrastructure, co-location, and demand-based infrastructure.

The study identifies 30 potential domestic and export hydrogen hubs in Australia. In Victoria, the six potential sites are in Altona, Port Anthony, Port of Hastings, Port of Melbourne, Port of Geelong, and Portland (Arup Australia 2019).

KPMG received ARENA funds to develop an assessment framework including an assessment tool (the H2City Tool) for early concept screening of potential communities suitable for converting their energy usage to green hydrogen. Comparing a green hydrogen and an electrification pathway allows quantitative assumptions along the hydrogen value chain and qualitative assumptions for policy development. Input factors for the gasification pathway include a percentage of hydrogen and gas blending, production location, gas networks, and local infrastructure. Input factors for the electrification pathway include energy mix to replace natural gas use, availability and size of on-site generators, and other local infrastructure factors. As a result, location opportunities are identified that can be selected to do further scoping and detailed analysis (KPMG 2019). The assessment framework and tool help the decision-making process and help test identified hydrogen hubs by Geoscience Australia and Arup Australia.

Distribution and end-use

Frontier Economics, engaged by the federal Department of Industry, Science, Energy and Resources (DISER), provides an indicative analysis of the economics of blending up to 10% hydrogen with natural gas in Melbourne's gas distribution networks. It finds the business as usual case has the lowest financial cost, but the lowest cost scenario depends on when the gas displacement commences (2025 with electricity switching, 2030 with hydrogen blending), and hydrogen options with no storage have significantly higher financial costs (Frontier Economics 2020). This pathway will be used to inform section 2.3, Analysis of decarbonisation pathways. Non-financial costs and benefits were not modelled.

GPA Engineering, engaged by COAG, the South Australian Government, and the Future Fuels CRC, analysed the technical impacts to end-users of natural gas in Australian distribution networks when up to 10% hydrogen (by volume) is mixed with natural gas. The approach includes a desktop review of current domestic and international research and testing. The report reviews the safety impacts and technical standards to identify legal barriers and develop recommendations. The review concludes the following:

- Domestic appliances (Type A), commercial and industrial appliances (Type B) are likely suitable for up to 10% hydrogen, but additional work on flame stability and materials must be done.
- Hydrogen blending cannot be used for compressed natural gas users (CNG), such as transport and vehicle fuel stations because of an increased risk of embrittlement in high-pressure, steel storage vessels, piping, and components.
- Feedstock users a, such as manufacturers, are likely suitable for up to 10%hydrogen, but additional work on the efficiency and safety of the applications must be done.
- Pipelines which connect the distribution network to the appliance are likely suitable for up to 10% hydrogen, but additional work on pipeline material must be done (GPA Engineering, 2019b).

GPA Engineering was also engaged by COAG, the South Australian Government, and the Future Fuels CRC to investigate a pilot project that allowed up to 10% hydrogen into gas distribution networks. The desktop review of current domestic and international research and testing found that the addition of 10% hydrogen (by volume) to a typical natural gas blend:

- has no significant impacts or implications on gas quality, safety and risk aspects, materials, network capacity, and blending (providing the mixture is homogeneous)
- has no significant impacts for the applicable Australian standards, but a review of Australian standards applicable to downstream installations and appliances must be completed
- has no significant implications for the applicable Australian state legislation, but a review of legislation covering downstream installations and appliances must be completed.

Finally, a set of recommendations were developed that address the identified potential barriers and considered timeframes for implementation. The work focuses on the impacts of hydrogen in distribution networks. Further work is needed to understand the implications for transmission networks (GPA Engineering 2019a).

Sector-coupling - power systems

GHD Advisory and ACIL Allen Consulting were engaged by the Victorian Department of Environment, Land, Water and Planning (DELWP) to assess possible future effects of green hydrogen production to support Australian power systems. The report analyses sector coupling opportunities for hydrogen facilities to deliver value through interaction with the power system. Power systems can benefit of the controllable production of hydrogen. Regarding the implementation, there are no material barriers but regulatory barriers. Policy changes will interact positively with Australia’s electricity systems as they evolve (GHD Advisory & ACIL Allen 2020).

Sector coupling - transport

The Australian Government is developing a Future Fuel Strategy that includes electric and hydrogen fuelled transport. Currently, the strategy is in a consultation process to incorporate stakeholder feedback. The release is planned for the first half of 2021. The strategy’s goal is to address barriers to the roll-out of new vehicle technologies, to increase consumer choice, and boost private and public investments in the early stage of the technologies. The identification and development of EV charging and hydrogen refuelling infrastructure are two of five priority areas. The Future Fuels Fund will co-invest with the private sector to demonstrate hydrogen refuelling infrastructure in more locations by 2030 (DISER 2021).

Aurecon Australia, engaged by COAG Energy Council, identifies opportunities for the early use of green hydrogen for Australia’s transport sector. The study’s approach includes an international market scan, the identification of preferred mode, the consideration of opportunities and constraints, and finally, the consideration of success criteria.

Benefits of hydrogen for transport include fuel security within Australia, better air quality and no tailpipe emissions, and a similar driving experience in use and range. The risks and barriers of hydrogen for transport include the consideration of fuel and refuelling infrastructure, limited supply, limited availability of fuel cell vehicles (FCEV) in Australia and high-cost competitiveness of FCEVs and alternatives such as battery electric vehicles (BEV). Therefore, a critical step to overcome the barriers to using hydrogen in near-term transport is demonstrations, pilots, and trials. The recommendations to bring down costs and scale up the technology include the commercialisation and infrastructure support of government fleets, trucks and bus corridors, and logistics hubs (Aurecon Australia 2019).

In 2018, Infrastructure Victoria prepared advice on the infrastructure that may be required to enable highly automated and zero emissions vehicles powered by electric batteries (EV) and hydrogen fuel cells vehicles (FCV) for the Victorian Government. Because FCVs are likely to be more costly than EVs, hydrogen is a more viable fuel solution for specific applications like heavy vehicles or a storage method for renewable energy beyond the transport sector. However, the infrastructure and resource requirements for a fully hydrogen-fuelled future are likely to be significant (Infrastructure Victoria 2018). KPMG’s energy analysis found that nearly 800 million kilograms of hydrogen would be needed per year to fuel all trips in Victoria using hydrogen FCVs in 2046 (Infrastructure Victoria 2018).

Co-location in wastewater treatment plants

Jacobs and Yarra Valley Water highlight how water utilities could play a pivotal role in accelerating Australia’s hydrogen industry development. Co-locating green hydrogen production with some types of oxygen-based treatments at wastewater treatment plans (WWTP) could bring wider economic and social benefits and could improve the prospects of developing hydrogen hubs (Jacobs & Yarra Valley Water 2020).

Jacobs examines the broader ESE sustainability challenges for large-scale hydrogen production in Australia. Hydrogen produced from grid-electricity may be acceptable if it creates lower net emissions for the end-use application. Recycled water from wastewater facilities could represent a sustainable, low-cost, and reliable alternative water supply (Jacobs 2019).

Chemical uses / ammonia

Natural gas is also used as a feedstock in some chemical processes. Australia has three highly gas-intensive manufacturing sub-sectors – polyethylene, ammonia and related chemicals, and alumina. Many of these companies are in Western Australia, where natural gas prices are lower than in the South East gas market. Natural gas makes up to 10% of these industries' input costs, and they consume more than 60% of the natural gas used in Australian manufacturing. Low-emissions ammonia can be replaced with renewable hydrogen, which is currently too expensive (Grattan Institute 2020).

Currently, hydrogen is largely used as an input for refining ammonia for the chemical production of fertilisers and explosives in Australia. Hydrogen as an energy source is estimated to be only 1% to 2% of Australia's total hydrogen consumption. Ammonia is widely seen as a viable method of storing and transporting hydrogen due to its high energy density, safety, and cost-effectiveness. Ammonia provides an early pathway for hydrogen industry development and can be leveraged to develop infrastructure and demand for other purposes (Deloitte 2019).

The future demand for hydrogen as fertiliser and in explosives is increasing marginally. Ammonia production facilities are projected to use hydrogen (in part) derived from electrolysis powered by green electricity sources by 2030. They can therefore function as energy storage units or back-up for energy producers using excess renewable energy. Ammonia production facilities can be built in areas where solar, wind or other green energy forms are largely available (Deloitte 2019).

The use of clean hydrogen as an industrial feedstock involves the direct displacement of hydrogen derived from SMR as the necessary production source. The input of clean hydrogen into ammonia and other chemicals such as methanol could renew demand for low carbon products in the petrochemical and refining industry. However, clean hydrogen as an industrial feedstock is not yet economically viable (CSIRO 2018).

Fertiliser company YARA has partnered with energy company ENGIE to develop a large-scale renewable hydrogen project in the Pilbara region in Western Australia. The objective is to decarbonise the hydrogen supply YARA's Pilbara fertiliser plant by taking advantage of the region's favourable renewable energy resources to produce green hydrogen and ammonia via electrolysis. The project received funding from ARENA. In the first phase, the technical feasibility concluded positively. Until 2030 in further three phases, the renewable energy share will be scaled up, and the production of green hydrogen and ammonia ramped up (ENGIE & YARA 2020).

Community trust

The University of Queensland has researched public attitudes to hydrogen production and consumption. The survey *The Australian Public's Perception of Hydrogen for Energy* (2018) focuses on understanding community knowledge of hydrogen and the potential for developing a long-term strategy in Australia.

The recommendations conclude that ongoing community engagement between government, industry, and academia for the development of a national hydrogen industry is necessary (University of Queensland 2018). COAG Energy Council also engaged the University of Queensland to develop the report *Community Trust in Hydrogen* which documents current knowledge of social issues surrounding hydrogen projects. It reviews leading practices of stakeholder engagement, communication strategies, findings from focus groups, and research activities across Australia. Some of the recommendations include:

- manage expectations and communicate realistic timeframes
- ensure some hydrogen is available for domestic use
- develop a standard framework for benefit-sharing
- clearly communicate the costs, risks, and benefits
- use case studies and pilot projects (University of Queensland 2019).

2.2.4 Biogas

Our literature review searched for biogas and biomethane as similar terms, although they are different. Biogas is the raw product from anaerobic digestions and consists of about 60% of methane. Biogas can be upgraded and purified to 100% biomethane. The minority of the identified publications deal with biogas or biomethane. The focus of current research is more general on bioenergy or biomass than biogas. Because of the lack of literature, these publications were also considered.

Technical Details

Biogas is produced from the anaerobic (oxygen-free) digestion of organic matter. It is typically composed of 50% to 70% methane (CH_4), 25% to 45% carbon dioxide (CO_2), and other gases in small quantities such as hydrogen sulphide (H2S), water vapor (H_2O), oxygen (O_2), ammonia (NH_3) and other trace gases (ENEA Consulting 2019).

Biogas use

Biogas is a form of renewable bioenergy that can be used to decarbonise gas. Biogas is a renewable, reliable, and local source of energy (Energy Networks Australia 2019). Biogas is considered emissions neutral as carbon is both absorbed as the plants grow and emitted as the gas is burnt.

Biogas can be used as a source of energy for heat and/or electricity generation. Local heat is produced via a boiler, commonly used at wastewater treatment plants (WWPT), meat processing, and agricultural farms like piggeries. Electricity is produced via a combined heat and power (CHP) unit and can be used onsite or fed into the grid.

Biogas can also be purified and upgraded to biomethane. Biomethane's chemical characteristics are close to natural gas. It is injected into the gas grid for storage and distribution for industrial and residential gas end-use. If biomethane is converted and compressed to a liquefied form, it can be transported in bottles or be used as a vehicle fuel.

Digestate is the remaining material after the anaerobic digestion of the biogas feedstock. Because it is nutrient-rich, it can be used as a fertiliser (ENEA Consulting 2019).

Biogas production

The production of biogas is a three step process see Figure 13 below (ENEA Consulting 2019):

1) Feedstock selection, collection, and processing
Various organic feedstocks like industrial food waste, agricultural waste, energy crops, sludge, and household waste are collected and transported to the biogas station. Land fill sites naturally release methane and other harmful gas, which is currently often unused and flared (burned without it being used to generate useful electricity or heat). Each feedstock is characterised by a different energy content that influences the amount and quality of biogas produced by anaerobic digestion.

2) Anaerobic digestion process
In the digester, the organic feedstock is biochemically digested into CO_2 and CH_4 by anaerobic microorganisms. The digester configuration depends on the feedstock, which needs different parameters like moisture content, range of temperature, stage of digestion, and stock flow.

3) Use of products from anaerobic digestion
The end products include biogas, biomethane and digestate (which can be used as fertiliser).

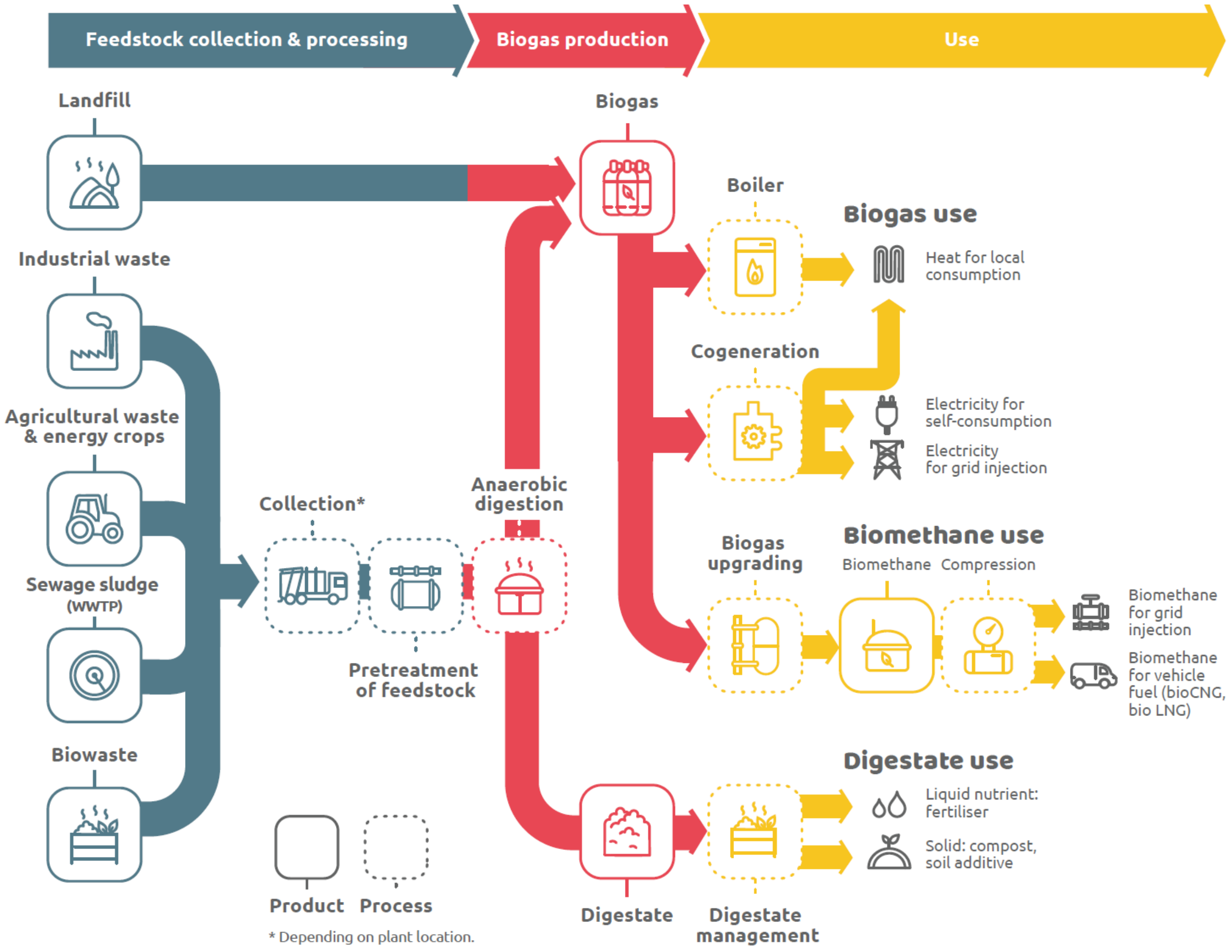


Figure 13: biogas value chain (ENEA Consulting 2019)

Environmental, social, and economic (ESE) assessment

The identified literature does not provide much information for a detailed ESE assessment of biogas. There is too much uncertainty regarding the size and composition of biomass resources in Australia, affecting its correct ESE assessment. The literature focuses more on biomass availability and potentials in Australia. Especially for biogas, the future potential depends not only on the availability of feedstocks but also on the use of these resources in other industries.

Deloitte Access Economic has used the Australian Biomass for Bioenergy Assessment (ABBA) data from the Australian Renewable Energy Mapping Infrastructure (AREMI) platform to estimate the biogas potential in each state. Wet streams like urban waste, livestock residue, and food processing residue are well suited to biogas production. Agricultural crop residues can be used for biogas production. However, these compete directly against other agricultural uses like food and fibre production (Deloitte Access Economics 2017).

The Deloitte study found Victoria has a biogas potential of 48 PJ, the fourth lowest in Australia. At 27%, Victoria has the second-lowest total potential biogas supply as a share of regional gas consumption. In other words, only around a third of Victoria's total existing natural gas consumption could be covered by biogas. The share is low because Victoria's natural gas consumption is very high compared to the national average (Deloitte Access Economics 2017).

In 2016-17, electricity from biogas generated about 1,200 gigawatt hours (4,320 terajoules (TJ)), or 0.5% of national electricity generation. In 2017, there were 242 biogas plants in Australia, half of which were landfills collecting landfill gas. Roughly half of this landfill gas was not used as an energy source and was flared (burned).

The total estimated future biogas potential in Australia is 103 terawatt hours (371 PJ); comparable with the current biogas production in Germany. Australia's future biogas potential is equivalent to almost 9% of Australia's total energy consumption of 4,247 PJ in 2016-2017. Considering the current average size of biogas units in Australia, this could represent up to 90,000 biogas units. Moreover, the investment opportunity for new bioenergy and energy from waste projects is estimated at AUD $3.5 to $5.0 billion, with the potential to avoid up to 9 Mt of CO_2 emissions each year. Besides biogas projects, this investment opportunity includes other waste to energy technologies such as direct combustion of waste (biomass combustion or waste incineration) (ENEA Consulting 2019).

Figure 14 shows that most biogas production in Australia is used for heat and electricity generation or is being flared. Almost half of the landfill gas collected is currently flared. That can be explained by several reasons, including the absence of infrastructure for converting landfill gas into electricity and the landfill gas's low methane content (compared to natural gas). More than half of the 122 plants rely on biogas production to self-sustain their heat and electricity demand or generate revenues from the heat and electricity sales. There is currently no biogas upgrading plant for biomethane production operating in Australia (ENEA Consulting 2019).

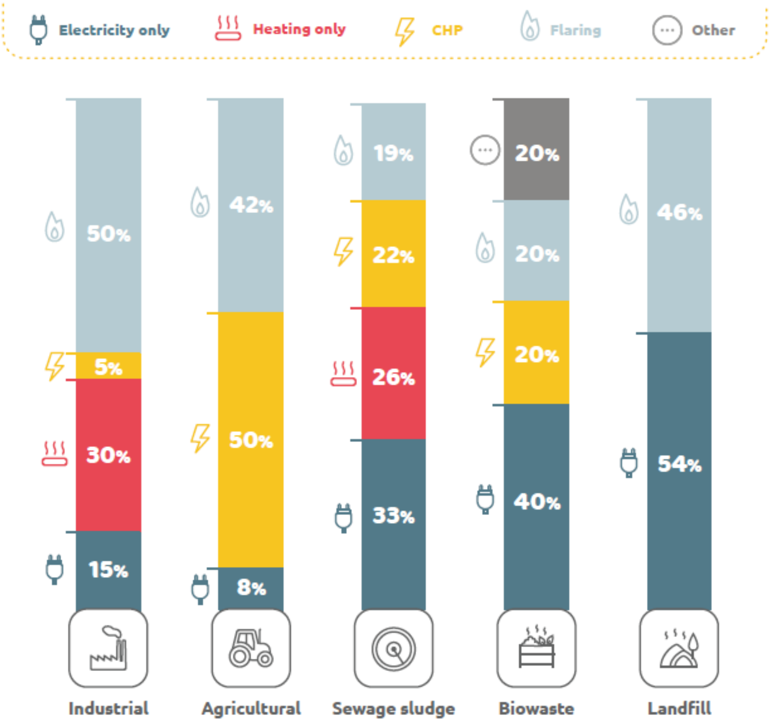


Figure 14: Utilisation of biogas in Australia (ENEA Consulting 2019)

In summary, biogas can contribute to Victoria's emission reduction target via three pathways:

- replacing the combustion of natural gas with biogas for energy purposes
- capturing methane emissions from landfills
- capturing methane emissions from animal waste and meat processing wastewater storage (ENEA Consulting 2019).

Globally, the costs of producing biogas today lie in a relatively wide range from USD $2 per Mega British Thermal Unit (MBTU) to USD $20 per MBTU[6] (see Figure 15). Household-scale biogas systems can also provide alternative heating and cooking fuels in developing countries. Commercial-scale biogas plants are more technologically sophisticated, requiring higher capital and operating costs. The total cost of biogas plants benefits from economies of scale: the larger the plants and the larger the amount of energy produced, the lower the total costs. Small biodigester plants average around USD $16 per MBTU. Large biodigester plants average around USD $9 per MBTU. Adapting a wastewater treatment plant to support biogas entails high upfront investment costs averaging around USD $15 per MBTU. Landfill gas extraction plants have the smallest production costs below USD $3 per MBTU (IEA 2020b).

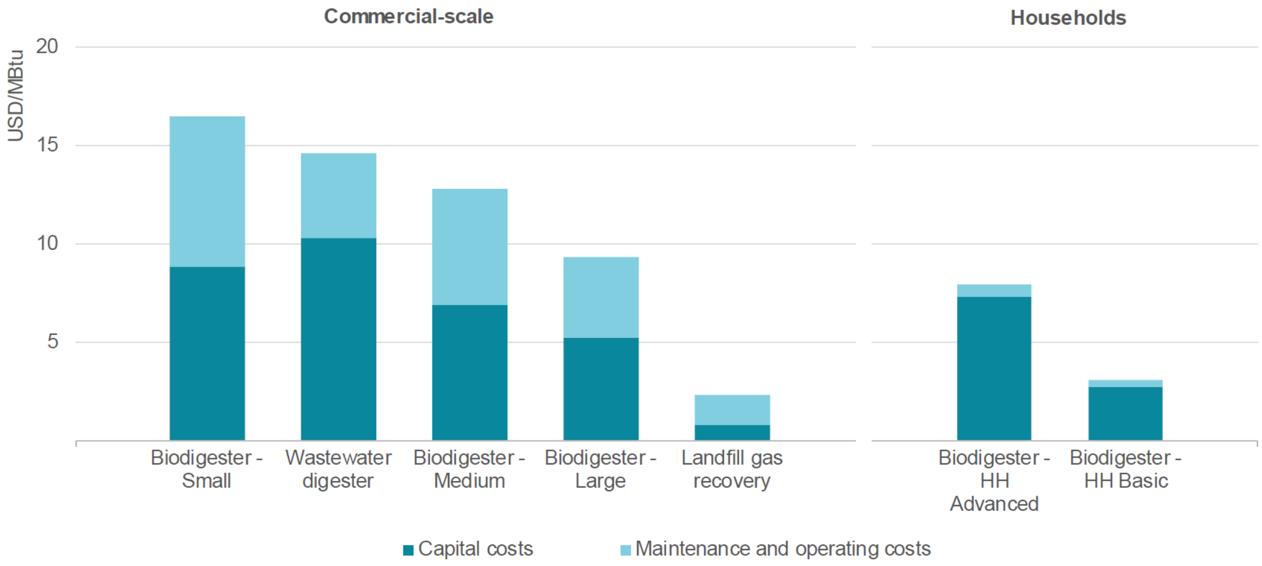


Figure 15: Average costs of biogas production technologies per unit of energy produced (excluding feedstock) in 2018 (IEA 2020b)

Around 70% to 95% of total biogas costs are for installing the biogas plant, and the remaining costs are for feedstock collection, biomethane upgrading, and grid injection. Costs for feedstock collection and processing vary between zero to negative prices, depending on if waste disposal is paid for, and up to USD $100 per tonne in some regions. Upgrading biogas to biomethane costs around USD $2 per MBTU to USD $4 per MBTU. Typical network connection costs are around USD $3 per MBTU, distributed equally between pipeline infrastructure, grid injection, and connection costs.

Literature Overview

Under-utilised biogas potential

The IEA Bioenergy country reports provide a detailed overview of national policy frameworks, energy supply, and the contribution of bioenergy, including biogas and biomethane across the globe. The IEA concludes that Australia has several comparative advantages that increase its potential to develop a sustainable and competitive bioenergy industry like:

- suitable climate, sunlight, and flat agricultural land for growing energy crops
- world-leading expertise in agricultural science
- strength in natural resources and infrastructure industry development
- existing regulatory frameworks on a federal level (Renewable Energy Target, Emissions Reduction Fund) and state level (*Victoria's Renewable Energy Action Plan;* Victorian Renewable Energy Target).

However, Australia's bioenergy potential is currently underutilised (IEA Bioenergy 2018). The IEA's outlook for biogas and biomethane answers why the biogas and biomethane potential is underutilised, not only in Australia but globally.

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[6] *1 MBtu = 1 GJ, 1 USD = AUD 1.30 -> USD 2/MBtu = AUD 2.5/GJ*

The IEA provides a global estimate of the sustainable potential for biogas and biomethane supply, based on a detailed assessment of feedstock availability and production costs across all world regions. Global, available feedstocks to produce biogas and biomethane are huge, but only a fraction of the technical potential is currently used. This is because feedstocks like crop residues or animal residues compete with food and agricultural land use. Also, natural biogas resources, like increasing amounts of municipal solid waste or wastewater, are unused. Another reason is that most biomethane potential is more expensive than natural gas. However, it is expected that biomethane production technologies will improve, and the cost gap to compete with natural gas will narrow over time. Biogas offers a local source of power and heat and clean cooking fuel for households. When upgraded, biomethane brings all the energy system benefits of natural gas without the associated net emissions. Therefore, realising the benefits of biogas and biomethane requires co-ordinated policymaking across energy, transport, agriculture, environment, and waste management (IEA 2020b).

ENEA Consulting, engaged by industry body Bioenergy Australia and the Australian Renewable Energy Agency (ARENA), provides an overview of Australia’s current and future potential biogas industry. Biogas is described as an opportunity as a renewable, reliable, and local energy source. The challenges lie in financial viability, policy conditions, and the complexity of project development and operation. Recommendations include a new policy design for transport and waste treatment to contribute to the development of local economies (ENEA Consulting 2019).

In 2020, Infrastructure Victoria prepared advice on recycling and resource recovery infrastructure for the Victorian Government, including developing residual waste-to-energy recommendations. Waste-to-energy facilities could stop some residual waste from going to landfill, particularly organic material, and recover some energy. Organic waste, which includes food and garden organics, is Victoria's largest waste stream at 35%. There is also a large amount of organic waste from the commercial and industrial sectors, but this data is not comprehensive. A recommendation includes developing anaerobic digestion capacity in Metropolitan Melbourne to process Melbourne’s organic waste as well as in regional Victoria, co-located with existing wastewater treatment plants and food production hubs. The solid residues that remain could be further reused and recycled. For example, digestate from anaerobic digestion processes could be transformed into a soil conditioner (Infrastructure Victoria 2020).

Biogas strategies and roadmaps

Currently, ARENA has provided funding to develop a national bioenergy roadmap. The goal is to identify the bioenergy sector’s role in Australia’s energy transition to reduce emissions. It will help to inform new investments and policy decisions in the bioenergy sector in Australia. The Bioenergy Roadmap is expected to be released in the first half of 2021 (ARENA 2021a).

In 2008, the Clean Energy Council developed a *Bioenergy Roadmap for Australia*. It detailed a series of objectives, issues, and actions that needed to be implemented to overcome barriers impeding the bioenergy industry’s growth and set target of 4% of Australia’s electricity generation being by bioenergy by 2020. (Clean Energy Council Australia 2008). Retrospectively, that target was not achieved. In 2018, bioenergy contributed only 1.4% to total electricity generation (IEA Bioenergy 2018), highlighting the lack of strong policy action on biogas and biomethane over the past decade.

In Victoria, there is no biogas strategy or roadmap. However, the Department of Environment, Land, Water and Planning (DELWP) has published a factsheet about bioenergy (DELWP 2020).

2.2.5 Carbon capture and storage (CCS)

Many of the identified publications in this literature review name CCS in the context of hydrogen usage. Therefore, technical details are briefly explained to understand CCS better. However, the identified literature delivers little detail about technical viability or ESE impacts.

Technical details

CCS involves capturing, transporting and storing greenhouse gas emissions from fossil fuel power stations, energy intensive industries, and gas fields.

CO_2 storage

There are two forms of how carbon can be permanently stored (Global CCS Institute 2020):

A) Oil and gas fields
There are various depleted oil and gas fields which have the capacity to meet global CO_2 storage requirements. But their geographic distribution is limited (Global CCS Institute 2020). CO_2 storage in depleted oil and gas wells has been limited to pilot demonstrations, but there are plans to develop commercial facilities (IEA 2020a).

B) Saline formations
Saline formations are rock formations with insufficient quality water instead of hydrocarbons. These formations are common, more widely spread, and have vast CO_2 storage resources. But there is no or low economic value to store

carbon (Global CCS Institute 2020). There is relatively limited experience in operating other geological storage options at scale (IEA 2020a).

CO_2 capture

Because of its numerous depleted oil and gas fields and existing pipeline infrastructure, Australia is well situated to take advantage of CCS technologies. Carbon capture, which involves capturing carbon during the production process and storing it, is more cost-effective when used to produce low-emissions hydrogen rather than to capture emissions from coal and natural gas combustion for electricity generation. However, carbon emissions are easier to capture during the hydrogen production process because the gas mixture produced during coal gasification and SMR is at a much higher pressure than the flue gases produced during electricity generation. To produce blue hydrogen from natural gas or coal at low emissions levels, carbon capture rates of 90% are required. These rates are technically feasible (COAG Energy Council 2019).

CO_2 Transport

If carbon is captured, it needs to be transported via pipelines to the final storage location. It is estimated that 5,000 km of large-diameter CO_2 pipelines would need to be constructed to meet Australia's emissions reduction goals using CCS. Currently, there is 50km in Australia. Liquified or gaseous CO_2 can also be transported via trucks and ships. Therefore, it is more efficient to have CO_2 separation and storage close together (Deloitte Access Economics 2017).

Environmental, social, and economic (ESE) assessment

For blue hydrogen production from fossil fuels combined with CCS, the environmental and financial viability, the geological availability, and public acceptance of CO_2 storage are essential requirements.

Further, CCS can also be used to help to transition coal-fired power plants and other emission-intensive combustion processes. If technologies that apply CCS to blast furnaces to capture emissions from the air are successfully commercialised, they could enable retrofits and play a vital role in addressing emissions from already built plants (IEA 2020a). Currently, most direct air capture projects are still under development.

Although global research on the storage of CO_2 has been done, experience in projects has shown the importance of site selection as all storage reservoirs are different and need extensive study to understand whether they are suitable, along with on-going monitoring in the initial decades of the project, adding to the total costs of CCS (Deloitte Access Economics 2017).

The Hydrogen Council says with CCS blue, low carbon hydrogen made from natural gas could be produced with costs only about 10% to 20% higher than conventional grey hydrogen. To create blue hydrogen, the carbon capture process cost is estimated to be USD $0.20 to $0.30 per kg for a Steam Methane Reforming (SMR) plant (pressurised steam and natural gas) and less than USD $0.10 per kg for an Autothermal Reforming plant (oxygen and natural gas). Costs for carbon transport and storage vary strongly depending on local availability and conditions. Also, the costs of CCS vary according to which type of hydrogen is produced. For example, brown hydrogen from coal produces four times more CO_2 per kg of hydrogen than blue hydrogen. Therefore, gasification requires higher sequestration volumes that affect the overall costs of CCS (Hydrogen Council 2020). Therefore, brown hydrogen with CCS is less viable than blue hydrogen with CCS.

Literature overview

The IPCC highlights the importance of reaching net zero emissions by 2050. All IPCC scenarios require CO_2 removal and the use of CCS to limit a global temperature rise. The scenario that does not utilise CCS requires the most radical changes in human behaviour (IPCC 2014).

The Global CCS institute, an international think tank based in Melbourne, lists four reasons for the need for CCS (Global CCS Institute 2020):

- achieving deep decarbonisation in hard-to-abate industries
- enabling the production of low carbon hydrogen at scale
- providing low carbon dispatchable power
- delivering negative emissions.

The institute's *Global Status of CCS Report* (2020) documents key industry milestones over the past 12 months, as well as key opportunities and challenges faced by the emerging sector. It says there are currently 65 commercial CCS facilities across the world (26 in operation, 2 suspended operation, 3 under construction, 13 in advanced development, 21 in early development). There are another 34 pilot and demonstration-scale CCS facilities in operation or development and 8 CCS technology test centres. Most of the CCS facilities are in the United States, Canada, and China (Global CCS Institute 2020).

The report finds Australia has a global advantage in CCS due to its potential for large storage capacity. Australia has an estimated geological storage potential using depleted oil and gas fields of 16.600 Mt. In Western Australia, the Gorgon CCS facility has a capacity of 3.4–4 Mt of CO_2 injection per year, the world's largest operating CCS facility. In South Australia, the Santos Cooper Basin CCS project is a commercial facility in advanced development. The project will capture and geologically store 1.7 Mt of CO_2 each year. Santos claims abatement costs of less than AUD $30 per tonne.

In Victoria, the Hydrogen Energy Supply Chain (HESC) project is a pilot plant under construction. The project is supported by the Victorian, Australian and Japanese governments and coordinated by a consortium of Japanese and Australian energy companies. Also, in Victoria, the CarbonNet project, within the Victorian Government's Earth Resources unit, is identifying and assessing geological storage resources to commercialise CO_2 storage in a future where users pay for CO_2 transport and storage business. Currently, the project has completed appraisal drilling and started industry stakeholder consultation on future commercialisation options (Global CCS Institute 2020).

There is much certainty around suitable CCS locations. Geoscience Australia has identified Australia's most prospective CCS areas (Geoscience Australia 2019). In Victoria, there are significant brown coal reserves in the Gippsland region and a developed offshore reservoir with known subsurface geology suitable for CCS (CSIRO 2018). However, because most projects are still in development, the technical and economic viability of CCS projects in Victoria is still uncertain.

2.3 Analysis of decarbonisation pathways

Different research organisations, think tanks, industry bodies, and consulting firms have explored possible pathways to decarbonising the energy sector in general and the gas infrastructure in Australia. The selection of literature is based on publications that contain the development of

- scenario descriptions
- cost benefit analysis
- energy system modelling
- roadmap or strategy development,
- and spatial analysis to identify feasible options and pathways.

Nine pathways are presented in the combined context of energy and chemical use. There is only one pathway in the context of energy use and no pathway in the context of chemical uses suggesting that there is a research gap for analysis of replacement of natural gas as an industrial feedstock. The analysis of pathways will look at the modelling used, ESE assessment, and implications for gas infrastructure.

Pathway summary

Table 13: Summary of proposed pathways for zero emissions chemical uses with gas in Australia and Victoria

Pathway	Input fuel	Methodology	Decarbonisation pathway
Pathway 1: (Energy Safe Victoria 2020)	Electricity Natural gas Hydrogen Biogas CCS	Scenario development	Energy Safe Victoria (ESV) describes four possible future scenarios with different levels of renewable and conventional energy production and consumption. The scenarios look at electricity and gas demand and supply. It describes the influence of new technologies and the role of policy.
Pathway 2: (Energy Networks Australia 2019)	Natural gas Hydrogen Biogas CCS	Vision development Scenario development	The pathway analyses four scenarios to achieve net zero emissions in the gas sector, including the projection of costs of the transition for Australia's gas infrastructure. Natural gas as an industrial feedstock is replaced using low carbon (blue) or net zero (green) gas. The vision concludes that net zero emissions can be reached with hydrogen at half the cost of electrification when Australia’s existing gas infrastructure and natural gas resources are used.
Pathway 3: (Frontier Economics 2020b)	Natural gas Hydrogen Biogas CCS	Scenario development Cost benefit analysis	The pathway contains an analysis of three scenarios to achieve net zero emissions in the gas sector, including a cost projection for the decarbonisation of Australia's gas infrastructure. Each of the three scenarios reaches net zero emissions but entail additional costs. In this study, the Renewable Fuels and the Zero-carbon Fuels scenarios have lower financial cost than the Electrification scenario, suggesting that there is value in continuing to make use of Australia’s gas network and resources. Natural gas as an industrial feedstock is replaced using low carbon (blue) or net zero (green) gas. In all scenarios, Victoria has the highest conversion cost due to its heavy reliance on natural gas as an input fuel in both residential, industrial, and business contexts.
Pathway 4: (Deloitte Access Economics 2017)	Natural gas Hydrogen Biogas CCS	Energy market modelling Levelised cost of energy	The pathway contains a cost analysis of three transformational technologies biogas, hydrogen, and CCS, to achieve net zero emissions for Australia's gas infrastructure. The analysis suggests a variety of decarbonised gas options are likely to be cost competitive with electrification over the long term. The decarbonisation of gas distribution networks using biogas and hydrogen (green, blue, and brown with CCS) would utilise the existing and highly reliable gas networks to deliver zero carbon energy. In Victoria, green hydrogen production from electrolysis via wind power is most favourable. Current low biogas resources cannot meet gas demand. The report finds Victoria has prospective CCS capacities.

Pathway 5: (AGIG 2018)	Electricity Hydrogen	Energy market modelling	The Australian Gas Infrastructure Group (AGIG) compares two scenarios: Full Electrification and (green) Hydrogen Conversion case, in the energy sector only. The cost analysis concludes that green hydrogen is 40% less expensive than full electrification of gas infrastructure for energy generation in Victoria.
Pathway 6: (COAG Energy Council 2019) & (Deloitte 2019)	Hydrogen	Energy market modelling Roadmap	Australia's *National Hydrogen Strategy* sets a vision for a clean, innovative, safe, and competitive hydrogen industry by 2030. It finds Australia should leverage its competitive advantage to produce green hydrogen from electrolysis to meet the global demand for emission free transport, utilities, electricity, heat generation, and industrial feedstock.
Pathway 7: ClimateWorks Australia 2020	Electricity Natural gas Hydrogen Biogas CCS	Scenario development Energy market modelling	The ClimateWorks scenario finds Australia can achieve net zero emissions before 2050 with fast deployment of mature and proven zero emissions technologies like biogas and CCS and the rapid development of emerging zero emissions technologies like green hydrogen in harder-to-abate sectors. It finds emissions reductions require action by governments, businesses, and individuals.
Pathway 8: (CSIRO 2018)	Hydrogen	Roadmap National and international cost and technology benchmark	The CSIRO hydrogen roadmap identifies several hydrogen use scenarios, the expected cost reduction of hydrogen supply, and the development of target markets based on when hydrogen could be commercially competitive with alternative technologies. In Victoria, brown hydrogen production via coal gasification in the Latrobe Valley presents the most viable hydrogen production project, likely to be available after 2030 (and has only low emissions if produced in conjunction with CCS). CSIRO finds green hydrogen with electrolysis is preferred due to its net zero emissions footprint.
Pathway 9: (Hydrogen Council 2017) & (Hydrogen Council 2020)	Hydrogen	Roadmap Stakeholder Consultation	The Hydrogen Council's hydrogen roadmap delivers a deep, global decarbonisation pathway for transport, industry, and buildings. It finds green hydrogen enables a renewable energy production and distribution system by 2050 and says Australia has great capacity to convert renewable power to green hydrogen for export.
Pathway 10: (Geoscience Australia 2019)	Hydrogen CCS	Spatial analysis	The maps produced by Federal Government agency Geoscience Australia show that most of Australia's coastal areas have elevated potential for green hydrogen production from electrolysis due to the unlimited supply of (desalinated) seawater and electrical and port infrastructure availability. Their analysis finds Australia has extensive fossil fuel resources that can be used with CCS to produce hydrogen with low carbon emissions (blue hydrogen). It finds that Victoria is well placed to deliver this using brown coal due to the co-location of fossil fuels, big storage reservoirs, access to water and ports, pipeline, and electricity network infrastructure, but that this is highly prospective.

2.3.1 Scenario description

Scenario development is a tool to help to make future decisions under uncertainty. Scenario planning identifies a specific set of uncertainties, different assumptions of what might happen in the future, and how this might affect decision making. Scenarios are the basis for any further quantification like a cost benefit analysis, energy system modelling, or spatial analysis.

Pathway 1: Energy Safe Victoria (ESV) 2020

ESV has developed four scenarios to address global and local challenges and opportunities for the future Victorian energy landscape's energy safety risks. The scenarios describe the electricity and gas market in Victoria. The developed scenarios are regarded as “pre-strategy” to build a basis for developing future energy strategies.

Modelling

ESV identified and formulated responses (strategic options) to each of these challenges and opportunities. The strategic options underpinned the development of the adaptive strategic roadmap. Using the OGSM method (Opportunity, Goal, Strategies, Measures), the project team translates the strategic options into concrete actions – determining timing, assigning ownership, and allocating people and resources to the strategic options that flowed from the scenarios (Energy Safe Victoria 2020). The model is a purely qualitative approach. There is no detailed analysis, or quantification of the opportunities, goals, strategies, or measures.

ESE assessment

Table 14 briefly summarises all assumptions and their environmental, social, and economic implications for the scenario planning.

Table 14: Summary of scenario description (ESV, 2020)

	Brave new world	Energy oligarchy	In it together	Good old days
Climate	Global reduction of emissions and early transition to renewables	Effects of climate change noticeable, but pro-coal agenda, no renewables	Global emission reductions targets but delayed transition to renewables	Increasing rejection of scientific evidence for climate change
Energy policy	Bipartisan Australian National Energy Policy (NEP), renewables subsidies and carbon taxes Federal more influential than state government	No coherent National Energy Policy (NEP)	Bipartisan, long-term diversified energy strategy, the National Energy Policy (NEP) Federal more influential than state government	Reactionary and politicised short-term energy policies No national energy policy (NEP) Funding of new coal power stations
Technological revolution	A government controlled technological revolution Internationalisation of technology regulation, Leading development of harmonisation of markets and standards	Polarising technological revolution with automation and robotisation No international coordination and harmonisation	Up-scale of proven technologies over disruptive innovations Internationalisation of technology regulation, late adapting to harmonisation of markets and standards	Backlash against new technologies Lack of international standards, complex and confusing regulatory landscape
Hydrogen	National hydrogen strategy for deployment of utility-scale hydrogen Conversion of pipelines for industrial and residential use	Missing out on hydrogen	Continued use of natural gas, small deployment of blue hydrogen & biogas Green hydrogen as export product for Asian markets	Missed commercialisation projects lowered hydrogen potential No use of hydrogen because not cost competitive
Energy market	Hydrogen powered grid as energy backbone No large-scale renewables, peak surpluses of rooftop solar generation High grid prices	Blackouts and brownouts because of decommissioning Widened 'energy gap' between energy self-sufficient and poor neighbourhoods High energy prices	Utility-scale grid as energy backbone Large scale solar, hydro but also nuclear power plants Low energy prices, low cost for network augmentation	Fossil fuel-based energy mix with frequent capacity issues

Gas infrastructure

Each of the scenarios has different implications for Victoria's gas infrastructure (Energy Safe Victoria 2020):

1) Brave new world

National Energy Policy (NEP) identified hydrogen reticulation as the optimal way to leverage and decarbonise the existing gas infrastructure. Complete electrification of energy was deemed too costly. Appliances are on the market that can operate safely on 100% hydrogen.

With blue hydrogen becoming more readily available and cost effective, the main bottleneck was converting pipelines and appliances. The NEP framework dictated an ‘all or nothing’ approach, e.g. full conversion with a phased neighbourhood-by-neighbourhood rollout. After limited trials with 100% hydrogen, reticulation to households in the more isolated markets of Western Australia and the Northern Territory concluded successfully, hydrogen conversion has started in Victoria, and the rest of the country, with the roll-out to be completed by 2040.

In order to lower the financial burden on the distribution network service providers and partnering gas companies, the conversion of the pipelines has been co-funded by the Federal Government through the renewable energy fund, paid for by a carbon tax on natural gas during the (lengthy) transition years, during which biogas was blended in.

2) Energy oligarchy

Blackouts and brownouts became commonplace as generating assets were decommissioned and not replaced, while ageing assets were operated well past their design lives with little maintenance. Energy prices have risen as utility-scale capacity has become scarcer and less reliable.

Given that many consumers are now taking charge of their own energy solutions, (investing in their own smart grids and local neighbourhood storage), investments in largescale, grid-based electricity generation has taken a sharp downturn. As a result, coal plants are now often at the end of, or past, their life span (even though they are still responsible for most utility-scale production).

3) In it together

The (partially subsidised) upgrade of the distribution network to polyethylene is completed, although there are still unresolved technical issues with hydrogen embrittlement of transmission pipelines. Governments subsequently agree to continue transmitting natural and biogas, but also blend hydrogen through the distribution network. ‘Blue’ hydrogen is still more expensive than biogas and Australian consumers do not regard it as ‘green’ enough. Therefore, its share in the blend is relatively small. Higher blends, or sometimes full hydrogen reticulation, is more the domain of industry.

4) Good old days

Blackouts and brownouts have become commonplace as generation is decommissioned and not sufficiently replaced, or ageing assets are operated well past their design lives.

Pathway 2: Energy Networks Australia (ENA) 2019

ENA provides its *Gas Vision 2050* that includes a description of four possible future scenarios to achieve net zero emissions. Energy Networks is the peak body of Australia’s gas distribution network.

Modelling

The visions are purely descriptive and based on balancing energy affordability, energy security and environmental outcomes. Assumptions for the vision are based on conclusions from a cost-benefit analysis of an electrification and low carbon scenario. Energy Networks engaged Frontier Economics and Deloitte Access Economics to do the modelling and its projected costs for the cost-benefit analysis. The vision is described as follows (Energy Networks Australia 2019):

Gas in a 2050 home uses distributed energy resources and sustainable gas. During the day, households generate much of their own electricity through solar PV. Hydrogen fuel-cell or battery electric vehicles are the main mode of family transportation. Green hydrogen, via the distribution network from the local hydrogen production facility, provides the home with fuel flexibility and powers the family’s hydrogen vehicles. Alternatively, zero emissions methane, produced from biogas and hydrogen, could meet home energy requirements with appliances that are available today.

Gas in cities in 2050 envisions city blocks as an integrated energy system where excess electricity generated from solar PV on buildings can be exported to charge utility-scale batteries or be converted to green hydrogen and zero emissions methane, which can also be produced from biogas. These gases can then be used to power transport around the city or be converted back to electricity. Green hydrogen and/or zero emissions methane production facilities can be located on the edge of cities allowing gas to be injected back into the distribution network for cooking or heating restaurants, businesses, and entertainment venues.

Gas for industrial uses in 2050 will see carbon capture and storage used to ensure that the CO_2 from industry and gas production is not emitted into the atmosphere. This will mean cleaner energy can be exported to Asia as LNG. Alternatively, CO_2 is used to manufacture specialty chemicals and materials, resulting in zero emissions from the gas industry. Waste materials from the food, agricultural and forestry sectors are processed to produce biogas that is shipped around the country for use in remote regions such as camping or remote mine sites, or for portable use around the home and city. Natural gas can be used directly or as blue hydrogen and is an important feedstock and energy source for materials manufactured domestically, such as fertiliser, plastics, cement, and metals.

Gas for 2050 power generation will be decarbonised and widely distributed using a wide range of technologies. While houses and cities generate their own power, the electricity grid provides additional resilience and connects the electrical demand of cities with power generation including large-scale hydro, wind, solar thermal and gas. Energy is stored in utility-scale batteries, as hydrogen gas (produced from electrolysis using excess renewable energy), biogas and in traditional pumped hydro. Along with natural gas, these batteries provide frequency and peaking support for the grid during times of high demand. These technologies combine to provide secure, lowest cost and low emissions electricity for use across the economy.

All four scenarios assume a continued use of “sustainable” gas but ENA’s vision assumes and recognises a transition to a decarbonised economy by 2050.

ESE assessment

ENA engaged Frontier Economics to develop more detailed scenarios to estimate the costs of different decarbonisation options, see Pathway 3: Frontier Economic 2020b. Based on the modelling, ENA came to the following conclusions:

- Deploying transformational technologies using existing gas infrastructure is more economically favourable than electrification. Electrification is the costliest scenario.
- The blue hydrogen scenario is lowest cost at a net increase of AUD $13.3 billion compared with the base case.
- The green hydrogen scenario ranks second at a net increase of AUD $15.3 billion compared with the base case.

ENA adds that the blue and green hydrogen scenarios are conservative, and further cost reductions could be achieved by including low cost biogas, cost improvements in electrolysis technology, or the repurposing of natural gas pipelines to transport hydrogen, which was not considered in the analysis (Energy Networks Australia 2019).

There is no environmental or social assessment on emissions savings or job creation.

Gas infrastructure

ENA comes to a similar conclusion as Frontier Economics, see Pathway 3: Frontier Economic 2020b:

- making continued use where possible of existing gas transmission and distribution networks to deliver energy can help avoid the material costs of building new assets, such as augmentation of the electricity transmission and distribution networks.
- the finding that both the blue and green hydrogen scenarios are lower cost than electrification suggests that there is value in continuing to make use of Australia’s gas infrastructure and Australia’s natural gas resources to deliver gaseous fuels to end-use customers.
- gaseous fuels are essential as industrial feedstock in all the scenarios. Some industries, such as mineral processing and chemical manufacture, cannot operate without these fuels. The electrification scenario required additional infrastructure costs to deliver this feedstock through localised hydrogen production.
- this finding also suggests that policies to achieve net zero emissions should be broad-based and not focus solely on promoting the electrification of all stationary energy end-use (Energy Networks Australia 2019).

2.3.2 Cost benefit analysis

Cost benefit analysis compares the costs and benefits of an intervention or scenario. The analysis only focusses on costs and benefits that are both expressed in monetary units. Other assumptions for the energy systems cannot be tested. ENA funded the following three studies.

Pathway 3: Frontier Economic 2020b

Frontier Economics was engaged by ENA to do a cost benefit analysis of three options to achieve net zero emissions and identify project costs for the decarbonisation of Australia's gas infrastructure in 2050.

Modelling

The model outcomes for the electricity sector in the Base Case and the three scenarios using Frontiers Economics’ wholesale electricity market model *WHIRLYGIG*. Input data and approach are transparent. The input assumptions align with the approach used by AEMO for the Integrated System Plan (ISP). For the modelling changes in consumption and costs for gas production, transport with electricity, gas and hydrogen are estimated and the net present value (NPV) of the scenarios are determined. The energy supply options are the following (Frontier Economics 2020b):

- **Base Case:** represents a current view on a business as usual outcome for the electricity and gas sectors in 2050. The Base Case is the scenario against which costs and benefits in the other scenarios are compared.
- **Electrification scenario**: all end-use natural gas consumption is replaced by customers switching from gas supply to electricity supply. The complete electrification of gas consumption is likely to be impractical,

particularly for industrial customers. For that reason, for industrial customers, the electrification scenario involves a mix of:

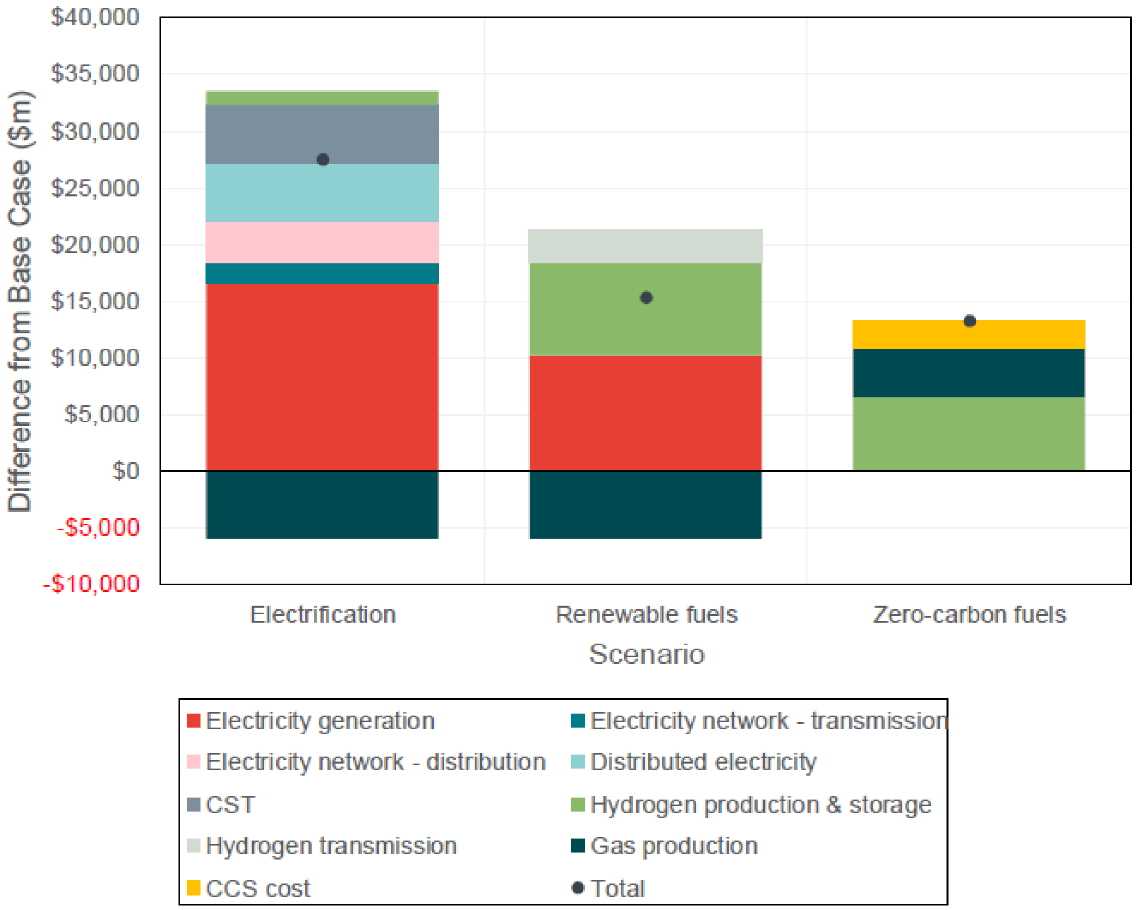
  - use of grid-sourced electricity
  - use of distributed electricity generation and storage
  - supply of heat through distributed solar thermal plant
  - use of hydrogen produced from on-site electrolysers supplied with grid-sourced electricity.

  Under each of these options, end-use customers will no longer use gas infrastructure to meet their energy needs.

- **Renewable Fuels scenario**: hydrogen is produced using alkaline electrolysis which replaces all end-use natural gas consumption. Replacement occurs to ensure that the energy content of hydrogen is equal to the energy content of displaced natural gas.
- **Zero-carbon Fuels scenario**: hydrogen produced using SMR of natural gas with CCS replaces all end-use natural gas consumption. The scenario is otherwise like the Renewable Fuels scenario.

ESE assessment

The analysis focuses on a cost-benefit comparison of the three scenarios compared to a base case. Therefore, a detailed conclusion can be made for the economic assessment, but less social or environmental assessment. Each of the three scenarios assumes reaching net zero emissions from the stationary energy sector in 2050. In contrast, in the Base Case there are continued emissions associated with the end-use of natural gas that would need to be offset to reach net zero emissions. Each of the three scenarios is more costly in 2050 than the Base Case (that is, incremental costs relative to the Base Case are positive). That is consistent with the expectation that shifting away from the Base Case of consumption of electricity and gas to a scenario that meets net zero emissions from the stationary energy sector will be more costly. The results of the cost-benefit analysis are presented in Figure 16.



Source: Frontier Economics' modelling

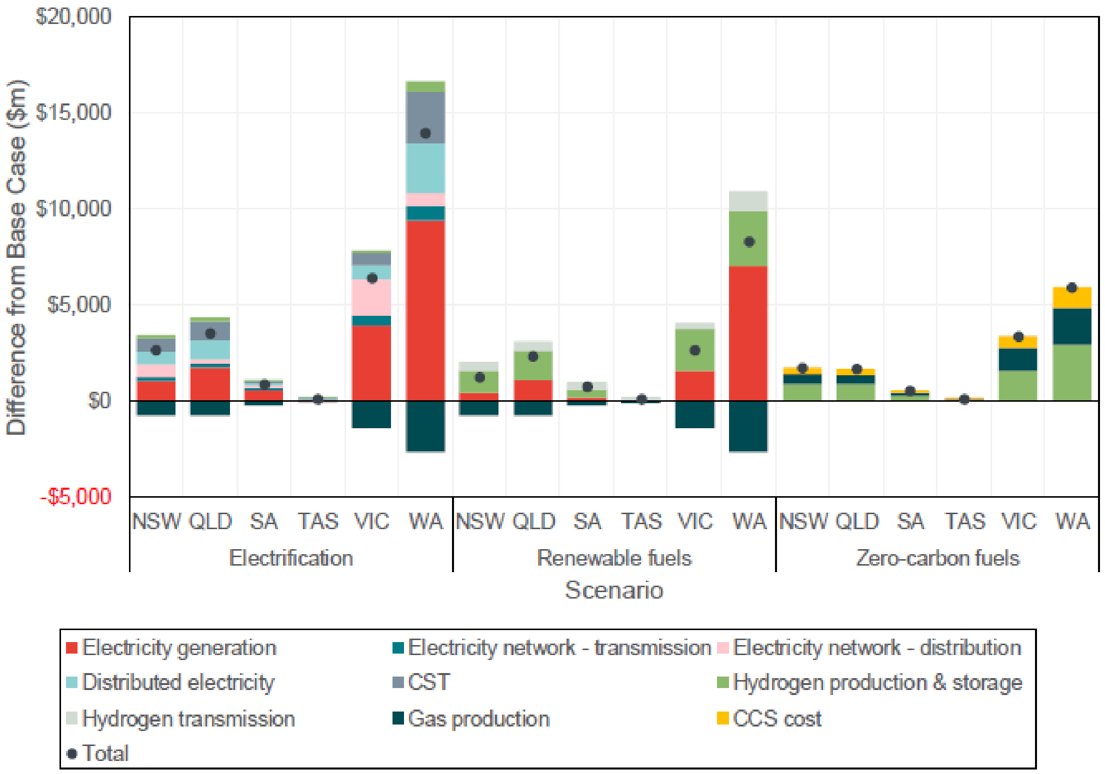
Figure 16: Cost-benefit analysis summary by components ($2020) (Frontier Economics 2020b)

There are significant additional electricity network costs associated with the electrification scenario. Of the three scenarios, the highest costs are the electrification scenario. Even in 2050, the costs of generation to meet industrial customers' energy needs using gas in the Base Case are significant.

The renewable fuels scenario is lower cost than the electrification scenario. The combined cost of building electrolysers and supplying them with electricity to replace all gas consumption is lower than the combined cost of the mix of grid-sourced electricity required in the electrification scenario. While there are significant additional costs of electricity production and hydrogen production, there are no additional costs of energy distribution because of the ongoing use of the gas distribution network. Since the operation of electrolysers can be optimised to times of lowest cost electricity, the average cost of additional electricity is lower in the renewable fuels' scenario than the electrification scenario.

The zero-carbon fuels scenario is lower cost than both the renewable fuels scenario and the electrification scenario. The cost saving for the zero-carbon fuels scenario relative to the renewable fuels' scenario is largely driven by the fact that the gas used by the SMR is lower cost than the electricity used in the electrolyser. The gas delivered to the SMR can make use of existing gas transmission assets (which are no longer required for delivering gas to end customers), , which accounts for some of the cost saving, whereas the delivery of hydrogen from the electrolyser is assumed to require new investment in hydrogen transmission pipelines. Against this, the SMR requires additional cost to capture and store carbon, and this additional cost does not outweigh the savings from using gas rather than electricity.

In each scenario, higher net costs are generally associated with higher underlying natural gas consumption in the region, refer to Figure 17. Therefore, the cost of substituting alternative fuels, either hydrogen or electricity, is higher than supplying equivalent end-use energy from business-as-usual arrangements. Victoria uses significantly more gas than electricity, which means that the installed generation capacity is much higher where gas end-users switch to electricity and/or hydrogen. Due to Victoria's high dependency on gas, costs of electricity network upgrades are the highest in Australia. In all scenarios, Western Australia and Victoria have the highest gas production and transmission cost differentials due to their heavy reliance on natural gas as an input fuel. Due to their high levels of natural gas demand, Western Australia and Victoria have the highest cost for hydrogen production and storage and the associated costs for CCS.



Source: Frontier Economics' analysis

Figure 17: Cost-benefit analysis summary by components and regions ($2020)

Gas infrastructure

Frontier Economics did a detailed cost benefit assessment for the needed infrastructure upgrades for electricity, gas, and hydrogen networks. Making continued use of existing assets to deliver energy, such as the existing gas transmission and distribution network, where possible, can help avoid the material costs of investing in new assets to deliver energy, such as augmentation of the electricity transmission and distribution network.

Both the renewable fuels scenario and the zero carbon fuels scenario is lower cost than the electrification scenario, which suggests that there is value in continuing to make use of Australia's gas network and Australia's natural gas resources to deliver gaseous fuels to end-use customers.

Gaseous fuels are essential as industrial feedstock in all the scenarios. If gaseous fuels (either natural gas, hydrogen, biogas, or renewable methane) are not available, the industries that rely on this feedstock would not be viable.

For industries that use gas for heat, there is uncertainty about the practicality of switching these energy requirements entirely to grid-sourced electricity. Particularly for higher temperature requirements, it is unclear that grid sourced electricity is a practical alternative for all applications.

The analysis finds policies to achieve net zero emissions should be broad-based and should not focus solely on promoting the electrification of all stationary energy end-use.

Pathway 4: Deloitte Access Economics

Deloitte Access Economics was engaged by ENA to do a cost analysis of three key transformational technologies biogas, hydrogen, and CCS.

Modelling

Deloitte has developed an internal energy market modelling to analyse the levelised cost of energy. Data input is based on publicly available and internal analysis-based sources (Deloitte Access Economics 2017).

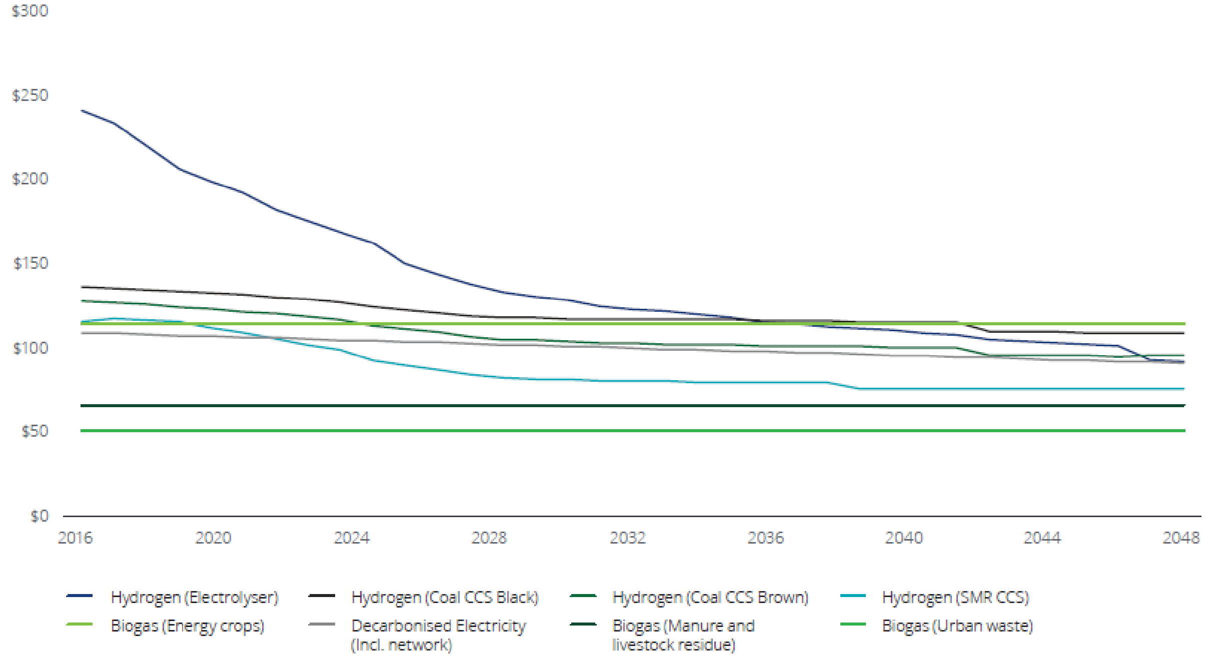


Figure 18: LCOE in $/MWh decarbonisation approaches to 2050 ($/MWh H2 -> $/GJ H2 conversion factor 3.6) (Deloitte Access Economics 2017)

ESE Assessment

The levelised cost of energy (LCOE) estimates the cost of producing decarbonised gas. It is a ratio of the total cost of producing energy over the energy output, presented in net present value terms.

In 2016, biogas was the cheapest option for decarbonisation of energy provided by gas networks. The cheapest form of biogas feedstocks includes energy crops with AUD $16/GJ, manure and livestock residue with AUD $18/GJ and urban waste with AUD $30/GJ. Because biogas technology has already reached a high technology maturity, production costs remain stable until 2050. Hydrogen production costs vary depending on the used technology. Hydrogen production from SMR and gasification already have a high technology maturity. There is less potential for cost reductions, starting from AUD $32.19/GJ for SMR and AUD $39.91/GJ for gasification in 2016 to expected cost reduction to AUD $20.94 for SMR to AUD $30.13 for gasification in 2050. Currently, hydrogen produced from electrolysis is with AUD $67.04/GJ the highest costs. But depending on the level of investments in technology development, hydrogen from electrolysis has the greatest potential for cost reductions with AUD $25.43/GJ by 2050. Appliance and network conversion costs add on to the large-scale hydrogen deployment. However, the additional costs are incrementally higher compared to the all-electric alternative. The decarbonised electricity scenario includes additional costs such as firming and network augmentation to replace gas with electricity. Currently, it is the second cheapest from gas production with around AUD $29/GJ. In 2050, the potential for cost reductions is low with costs of with AUD $26/GJ and other cheaper options available (Deloitte Access Economics 2017).

Deloitte Access Economics analyse the emission reduction potential of biogas and hydrogen per energy unit but does not model overall emission savings of the scenarios. Also, there is no social assessment of the low emission options.

Gas infrastructure

The analysis concludes that there are a variety of zero emission gas options that are likely to be cost competitive with an all electrification scenario by 2050. The use of biogas and hydrogen utilises the existing gas networks to deliver zero emission energy. Also, repurposing the large gas network with decarbonised gas is likely to lower the overall cost. Biogas can be fed into the network or burned locally to produce electricity or heat. Biogas can be used as a feedstock for industrial processes. Hydrogen can serve new markets like the large-scale energy storage with hydrogen or the transport of hydrogen for powering vehicles. In summary that includes:

- increased consumer choice
- use of the gas networks and infrastructure to store electricity by coupling of electricity and gas networks through electrolysis, potentially improving the utilisation and integration of variable renewable generation.
- potential to export energy in the form of hydrogen or ammonia
- may provide spill over development benefits for hydrogen fuel cell transport.

However, the analysis concludes hydrogen would require a conversion of pipelines and appliance, which is no technical limitation. Therefore, a policy should support a broad range of decarbonisation options like biogas and hydrogen (Deloitte Access Economics 2017).

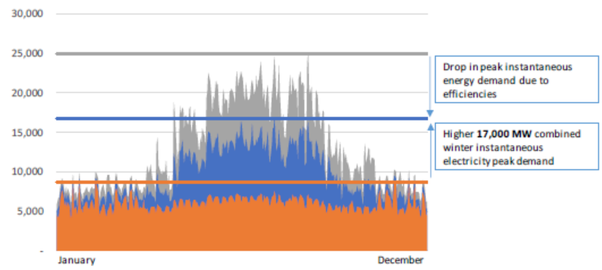
Pathway 5: AGIG 2018

Australian Gas Infrastructure Group (AGIG) analyse a decarbonisation pathway for Victorian gas consumption. The analysis only focuses on energy uses. Pathways for gas in industrial uses are not examined. AGIG own and operate natural gas infrastructure.

Modelling

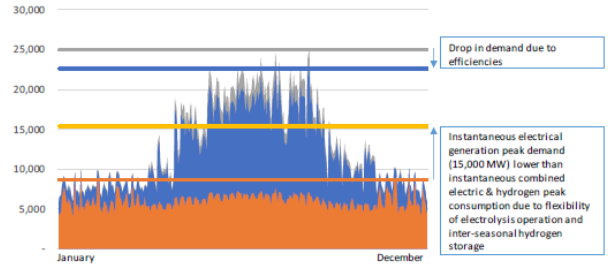
AGIG worked with Deloitte's energy market modelling to analyse decarbonisation pathways for Victorian gas consumption. There is no detailed information on the reference or the method of modelling. The analysis use AEMO data for energy consumption in 2017.

AGIG proposes two pathways - the Full Electrification case, replacing all-natural gas consumption with electricity, and the Hydrogen Conversion case, using existing natural gas infrastructure including appliances and networks to transport hydrogen produced through electrolysis. Both pathways assume that the needed electricity is generated from renewable sources, the Renewable base case.



Source: AGIG analysis and AEMO data

Figure 19: Combined daily maximum hourly demand in MW – Full Electrification (AGIG 2018)



Source: AGIG analysis and AEMO data

Figure 20: Combined daily maximum hourly demand in MW – Hydrogen Conversion (AGIG 2018)

ESE assessment

In the full electrification scenario, both total energy consumption and combined maximum peak demand are lower than the base case due to the assumed appliances efficiency and the changeover from gas to electric. Because gas consumption is replaced by electricity, total energy demand increases from 9,000 MW (base case) to 17,000 MW, see Figure 19. As disadvantages in this case, intraday peak shaving, and inter-seasonal storage with gas supply for electricity generation cannot be used. In the hydrogen conversion scenario, both the total energy consumption and combined maximum peak demand are lower compared the base case due to the assumed appliances efficiency and the changeover from gas to hydrogen. Because electrolysis needs additional electricity, total energy demand increases from 9,000 MW (base scenario) to 15,000 MW. But compared to the full electrification case the total energy demand is 2000 MW lower due to the operational flexibility of electrolysis and long-term hydrogen storage (see Figure 20). When cost in both scenarios are compared, the hydrogen pathway is 40% less expensive than full electrification for decarbonisation of the gas consumption in Victoria (see Figure 21) (AGIG 2018).

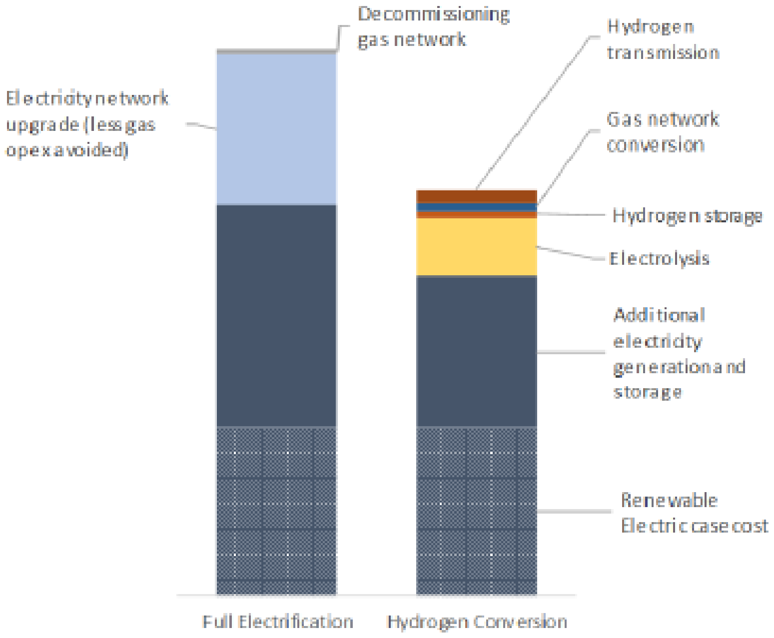


Figure 21: Relative cost comparison of decarbonisation pathways (AGIG 2018)

Gas infrastructure

The full electrification pathway has significant higher investment costs in electricity distribution and transmission network upgrades. Additional electricity network upgrades, generation and storage are needed to meet the higher peak energy demand. On top are costs for decommissioning services and mains and satisfying licence requirements to remove transmission pipeline assets. The hydrogen conversion pathway adds flexible load to the electricity system that better responds to peaks and reduces the cost for the upgrade of the electricity network. On top are costs of conversion for replacing cast iron pipes to polyethylene pipes, hydrogen storage and electrolysis. (AGIG 2018). Since the costs are significantly lower in comparison, the hydrogen conversion pathway including the continued use of the existing gas infrastructure is preferred.

2.3.3 Energy system modelling

Energy system modelling analyses energy systems with computer models. Commonly, these models employ scenarios to analyse different assumptions about technical and economic conditions. Outputs may include energy quantities, system feasibility, emissions, energy efficiency of the system, etc.

Pathway 6: COAG Energy Council 2019 & Deloitte 2019

COAG Energy Council developed a hydrogen roadmap. The roadmap is based on a detailed scenario analysis, which was developed by Deloitte. Deloitte develops and models four possible policy scenarios for hydrogen pathways for Australia by 2050.

Modelling

The energy market modelling is based on external forces like international and domestic policy, technological advances, and consumer acceptance. Internal forces include the domestic and international outlook for hydrogen development, supply, including the costs of natural resources to produce hydrogen, substitutes, new entrants to the market and international competitiveness. Data input is based on publicly available and internal analysis-based sources (Deloitte 2019).

The modelling analyses the role of Australia in global hydrogen demand. Depending on the scenario, the range of additional global hydrogen demand is between 2 Mt and 9 Mt in 2030 and from around 20 to over 230 Mt in 2050, see Figure 22 (COAG Energy Council 2019).

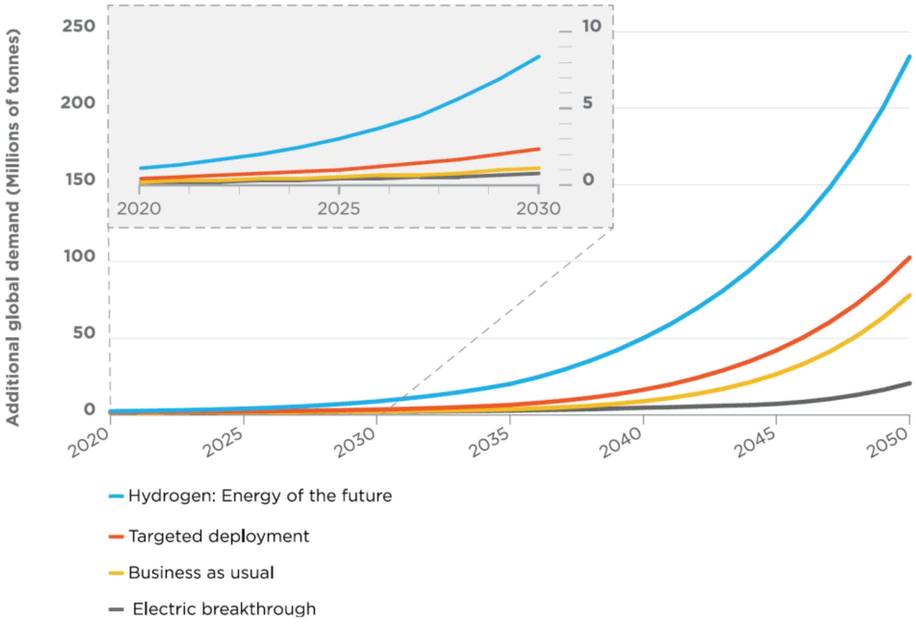


Figure 22: Global hydrogen market growth scenario outcomes (COAG Energy Council 2019)

The hydrogen - energy of the future scenario has a strong uptake of hydrogen by 2050, with pipeline gas and transportation requirements driving the demand for Australian produced hydrogen (constituting 47% and 21% respectively of total hydrogen demand, see Figure 23). Due to global carbon emissions reduction commitments, Australia acts as a leading hydrogen exporter supplying up to 30% of the demand in some Asian markets, see Figure 24. In 2050, global hydrogen production is 234 Mt, with Australia producing around 20 Mt (Deloitte 2019).

The hydrogen - targeted deployment scenario uses hydrogen in targeted heavy emissions sectors such as steel making and heavy transport. Australia is a leading exporter but in a smaller, global hydrogen market. In 2050, global hydrogen production is 2 Mt, with Australia producing 1 Mt (Deloitte 2019).

The business as usual assumes scenario Australia falls behind global emissions reduction efforts. Although there is a global demand for hydrogen, Australia loses competitiveness to export rivals (Deloitte 2019).

In the electric breakthrough scenario, all energy demand is covered by renewables, including battery and pumped hydroelectricity as energy storage. Electricity replaces natural gas or other decarbonised gases in applications such as heating and cooking, and petrol and diesel for transport. In 2050, global hydrogen production is 21 Mt, with Australia producing 1 Mt (Deloitte 2019).

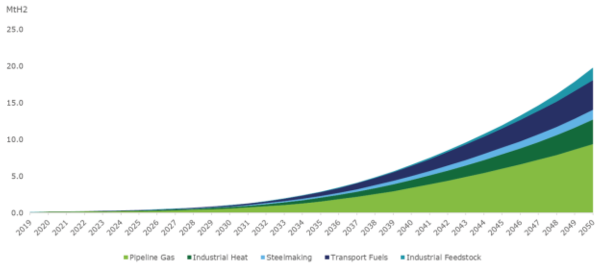


Figure 23: Additional Australian-produced hydrogen demand by application – Energy of the future scenario (Deloitte 2019)

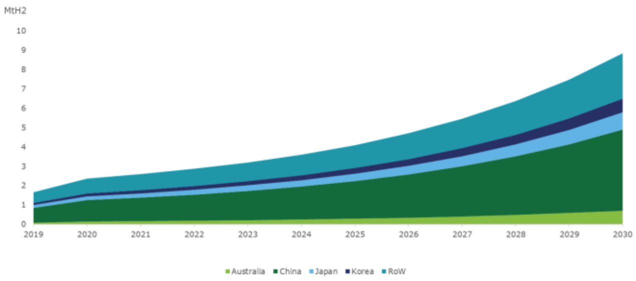


Figure 24: Additional Australian-produced hydrogen production by region – Energy of the future scenario (Deloitte 2019)

ESE assessment

Table 15 compares all four scenarios outcomes in 2030 and 2050 in detail.

In both hydrogen scenarios, the production of hydrogen boosts Australia’s gross domestic product (GDP) and employment. The economic impacts are the largest under the energy of the future scenario, with a GDP of AUD $26 billion and employment of 16,900 FTE higher than the BAU scenario in 2050. The targeted deployment scenario estimates a higher GDP of around AUD $11 billion and an additional 7,600 FTE equivalent than the BAU scenario by 2050.

However, in a relative sense, the economic impacts from a rapid expansion for both hydrogen scenarios are, with a share of 0.8% and 0.34% of the Australian GDP growth insignificantly higher than the BAU scenario. That is because the hydrogen-applying industries are small compared to Australia's established resource sectors and have only a small effect on Australia's overall economic growth. The relative effects on employment are similarly low relative to GDP, with an 0.09% and 0.04%employment increase in Australia's total (Deloitte 2019).

The modelling assumes that the energy of the future scenario produces green hydrogen (from electrolysis with solar and wind powered electricity) in 2050. The targeted deployment scenario produces blue hydrogen (from SMR with natural gas) due to a lack of policy support and technology improvements for electrolysis. Except for the BAU scenario, CCS is used in all scenarios.

Under the energy of the future scenario, CCS becomes price competitive with offsets in 2039. In the targeted deployment and electric breakthrough, CCS becomes price competitive with offsets in 2041. Looking at the emissions effects, the highest levels of CO_2 savings occur under the energy of the future scenario. The remaining three scenarios have similar high emissions outcomes due to different decarbonisation policies, lack of improved energy production methods, and continued used of fossil fuels in end-uses (Deloitte 2019).

Because of the electrolysis process, the energy of the future scenario has the highest water demand and land requirements for renewable energy production. Therefore, hydrogen production facilities must be located near suitable water and land resources for renewables.

Table 15: Scenario analysis for hydrogen use Australia in 2030 and 2050 (COAG Energy Council 2019)

	Hydrogen: energy of the future		**Hydrogen: targeted deployment**		**Electric breakthrough**		**Business as usual (BAU)**	
	2030	**2050**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**
Additional GDP above BAU (A$ billion) & share of total GDP (%)	0.6	26 (0.8%)	0.2	11 (0.34%)	Not modelled	Not modelled	-	-
Additional jobs above BAU (FTE) & share of total jobs growth (%)	487	16,923 (0.09)	145	7,628 (0.04)	Not modelled	Not modelled	-	-
Emissions avoided from use of Australian produced hydrogen (Mt CO_2-e)	Not modelled	135.78	Not modelled	56.8311	Not modelled	6.18	Not modelled	10.85
Emissions from Australian hydrogen production (Mt CO_2-e)	Not modelled	5.12	Not modelled	83.11	Not modelled	26.45	Not modelled	17.21
Ratio of global emissions avoided to emissions produced from Australian hydrogen (Mt CO_2-e)	6	27	0.6	1.2	0.5	0.5	0.3	0.6
Water requirements (GL)	16	207	5	91	3	15	2	24
Additional electricity requirements (TWh)	19	912	3	188	3	65	-	-
Land requirements for electrolysis if using 100% renewable electricity ($km^{2)}$	191 (solar) 1,234 (wind)	9,291 (solar) 60,160 (wind)	32 (solar) 209 (wind)	1,917 (solar) 12,415 (wind)	35 (solar) 228 (wind)	666 (solar),4,312 (wind)	3 (solar) 21 (wind)	56 (solar) 363 (wind)

Globally, hydrogen to decarbonise energy systems and replace natural gas for heating is gaining interest. However, the use of hydrogen in transport applications, such as heavy and light vehicles; chemical products, such as ammonia and refinery; and industries such as steel making, see hydrogen as a long-term alternative. Within the next decade, costs to produce clean hydrogen are expected to fall significantly. In certain sectors such as transport and industrial uses, the cost gap with other fuels is narrow and hydrogen becomes increasingly competitive in Australia, see Figure 25 (COAG Energy Council 2019).

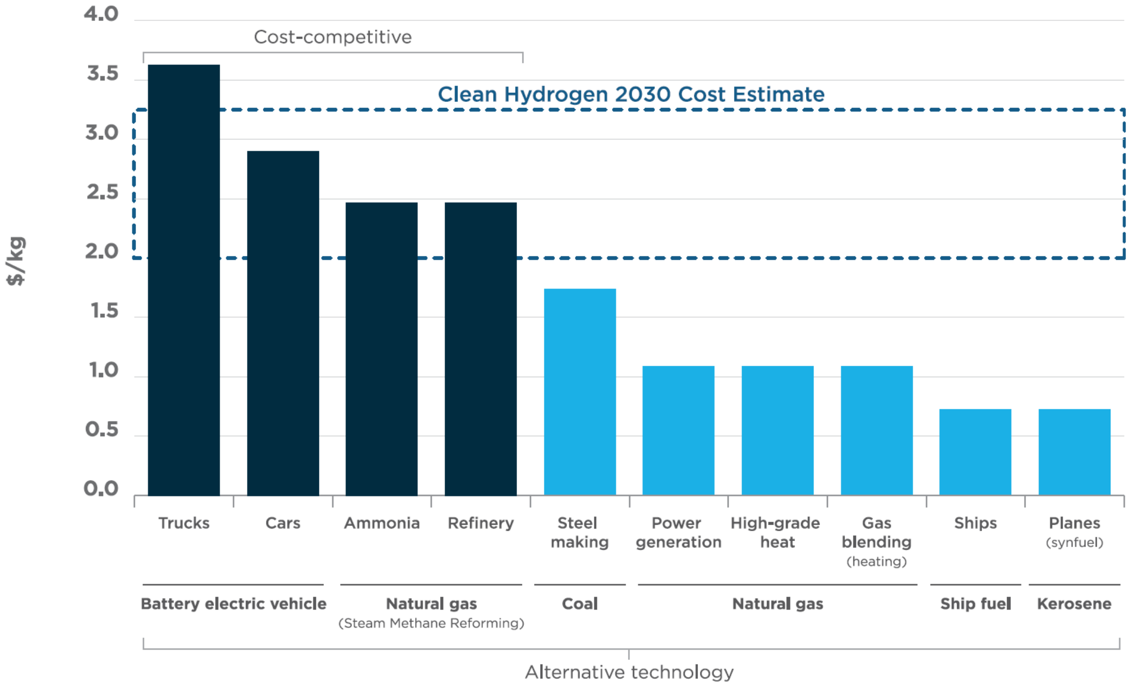


Figure 25: Breakeven cost of hydrogen against alternative technology for major applications in 2030 (COAG Energy Council 2019)

Gas infrastructure

The growth of the hydrogen sector can enhance the future value of gas infrastructure. Protecting the value of existing assets is an important consideration for the expansion of the hydrogen industry. But it must be balanced against other possible growth opportunities in relation to hydrogen (Deloitte 2019). Hydrogen hubs will make infrastructure more cost-effective, promote efficiencies from economies of scale, foster innovation, and promote synergies from sector coupling (COAG Energy Council 2019). The report does not further detail the re-use of gas infrastructure assets.

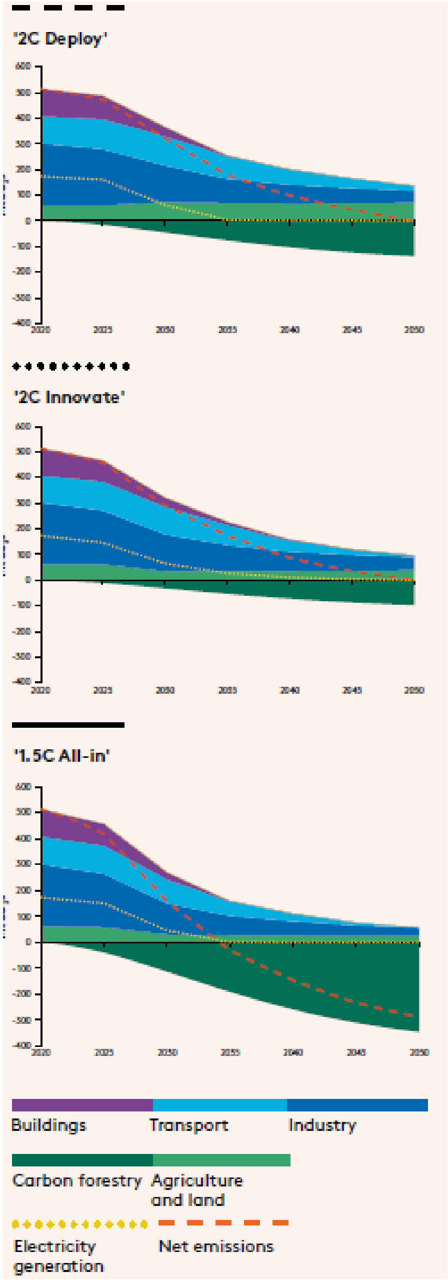
Pathway 7: ClimateWorks Australia 2020a

ClimateWorks, a think tank at Monash University, identify a range of mature, demonstrated, and emerging, rapidly developing technologies and supporting actions by government, business, and individuals to achieve net zero emissions before 2050. Aligning with the Paris climate goals, ClimateWorks models emissions reductions scenarios compatible with a two-degree global temperature limit.

Modelling

ClimateWorks utilises the Aus-TIMES Model, an Australian adaptation of a technoeconomic modelling framework developed by the International Energy Agency (IEA), to explore through scenario analysis three possible low-emission futures, refer to Table 16 (ClimateWorks Australia 2020a).

Table 16: Australian emissions by sector and by scenario (ClimateWorks Australia 2020a)

 	The first scenario ('2C Deploy') models emissions reductions compatible with a maximum two-degree global temperature rise, achieved primarily through direct government intervention with policies focused on regulating emissions and accelerating the deployment of demonstration and mature stage technologies. Key emissions-reduction solutions and supporting actions include: • 100% renewables, building energy efficiency, electric and fuel-cell vehicles for light road transport, carbon forestry, bio-feedstock, and industrial CCS • government regulation like taxes and incentives, targets and procurement for businesses, individual investments. The second scenario ('2C Innovate') shows how technology at the upper bounds of current expectations can facilitate the same outcome. In this model, emerging technologies create widespread change in emissions-intensive sectors, driven by supportive government and business action. Key emissions-reduction solutions and supporting actions include: • decreased cost of renewables and building energy efficiency, electrification and hydrogen for other transport, material substitution and hydrogen in industry • direct government and business investments. The third scenario ('1.5C All-in') models an emissions outcome compatible with limiting the global temperature rise to 1.5 degrees. It combines elements from the two earlier scenarios and assumes governments drive policies to limit emissions and facilitate technological innovations, with collaboration between policymakers, businesses, and individuals across all sectors.

ESE assessment

Across all scenarios, in Table 16, sectoral emissions trajectories reflect the maturity of zero-emissions technologies available to them. Buildings and electricity, which have access to mature zero emissions technologies, can achieve zero or near zero emissions around 2035. Transport, which has a mixture of mature and emerging zero emissions technologies, can achieves near-zero emissions by 2050. Industry and agriculture have significant residual emissions by 2050, reflecting the gap of available to zero emissions technologies.

Key differences between the scenarios include the amount of residual emissions by 2050. That reflects the accelerated efforts to develop and deploy zero emissions technologies in hard-to-abate sectors. The carbon forestry level required to achieve the 1.5 degrees carbon budget is much higher than that required to achieve the 2 degrees carbon budget, refer to Table 17 (ClimateWorks Australia 2020a).

For instance, government figures project a decline of national emissions by 16% on 2005 levels by 2030. In contrast, both the '2C Deploy' and '2C Innovate' scenarios benchmark a decrease of 37% to 43% while the '1.5C All-in' scenario arrives at 69%.

Looking at the biogas and hydrogen in the transport sector, both the '2C Deploy' and '2C Innovate' scenarios project an increase of volume of zero-emissions fuels by 171% to 265%. For the '1.5C All-in' scenario an increase by 338% is required. Therefore, investment in research, development and demonstration will be required to progress zero emissions technologies in non-road transport, likely to rely on electrification for short-haul, and biofuels, synfuels, ammonia and hydrogen for long-haul transport (ClimateWorks Australia 2020a).

The transition requires strong action by every level of government, businesses, and individuals to support technology development, demonstration and deployment (ClimateWorks Australia 2020a). An economic assessment of the realisation of the scenarios is not provided.

Table 17: Emissions and technology benchmarks of progress towards net zero emissions by 2050 (ClimateWorks Australia 2020a)

	2 C Pathways in 2030 (change versus 2020)	**1.5 C Pathway in 2030 (change versus 2020)**
Net annual emissions	37%-43% decrease	69% decrease
Technologies		
Share of renewable electricity generation	70%-74% (currently 25%)	79% (currently 25%)
Electric cars (BEV and FCEV)	50% of new car sales, 15% of total fleet (currently <1%)	76% of new car sales, 28% of total fleet (currently <1%)
Electric trucks (BEV and FCEV)	25%-39% of new truck sales, 8%-13% of total fleet (currently <1%)	59% of new truck sales, 24% of total fleet (currently <1%)
Volume of zero emissions fuels (bioenergy and hydrogen)	171%-265% increase	338% increase
Share of electricity in energy used for steel production	16%-20% (currently 11%)	27% (currently 11%)
Carbon forestry	~ 5 million-hectare (Mha) plantings	~ 8 Mha plantings
Energy		
Total final energy use	3%-8% decrease	16% decrease
Residential building energy intensity	44%-48% decrease (improvement)	49% decrease (improvement)
Commercial building energy intensity	16%-25% decrease (improvement)	28% decrease (improvement)
Share of electricity in residential buildings	76%-78% (currently 49%)	75% (currently 49%)
Total energy use (industry)	4%-10% decrease	15% decrease
Share of electricity and zero emissions fuels in total energy use (industry)	30%-32% (currently 25%)	33% (currently 25%)

Gas infrastructure

The ClimateWorks analysis focuses on general energy market transition modelling for emissions reduction. Natural gas is replaced by switching to electrification or by using sustainable gases like biogas or green hydrogen. The modelling gives no indications of the implications for gas infrastructure.

This decreased production (driven predominantly by global demand), combined with energy efficiency improvements and electrification of LNG liquefaction, leads to significant reductions in energy use for gas mining and LNG. Both residential and commercial buildings can shift reliance on gas to electricity, with many electrical appliances now more energy efficient and cost effective than their gas counterparts. Hydrogen shows potential for replacing coking coal in the steel manufacturing process and CCS respond to non-energy emissions such as fugitive methane in gas extraction. Also, hydrogen fuel cell and electric vehicles for truck fleets, heavy and long-haul road freight will drive down emissions (ClimateWorks Australia 2020a).

2.3.4 Hydrogen roadmaps

There is much uncertainty as to when hydrogen will become cost competitive with alternative technologies and gas options. Hydrogen roadmaps can help to inform timely investment decisions.

Pathway 8: CSIRO 2018

In 2018, CSIRO developed the National Hydrogen Roadmap, demonstrating pathways to an economically sustainable hydrogen industry in Australia. Data input is based on publicly available sources.

Modelling

CSIRO uses a national and international cost and technology benchmark to develop the hydrogen roadmap. The roadmap provides a detailed value chain analysis that identifies key investment areas for hydrogen applications and describes a best-case scenario in 2030.

ESE assessment

Figure 26 shows the expected cost reduction of hydrogen supply and the development of target markets based on when hydrogen could be commercially competitive with alternative technologies. From this, key investment priorities and market barriers can be derived. Applications above the hydrogen cost curve experience barriers in infrastructure. Applications below the hydrogen cost curve are cost competitive use cases (CSIRO 2018).

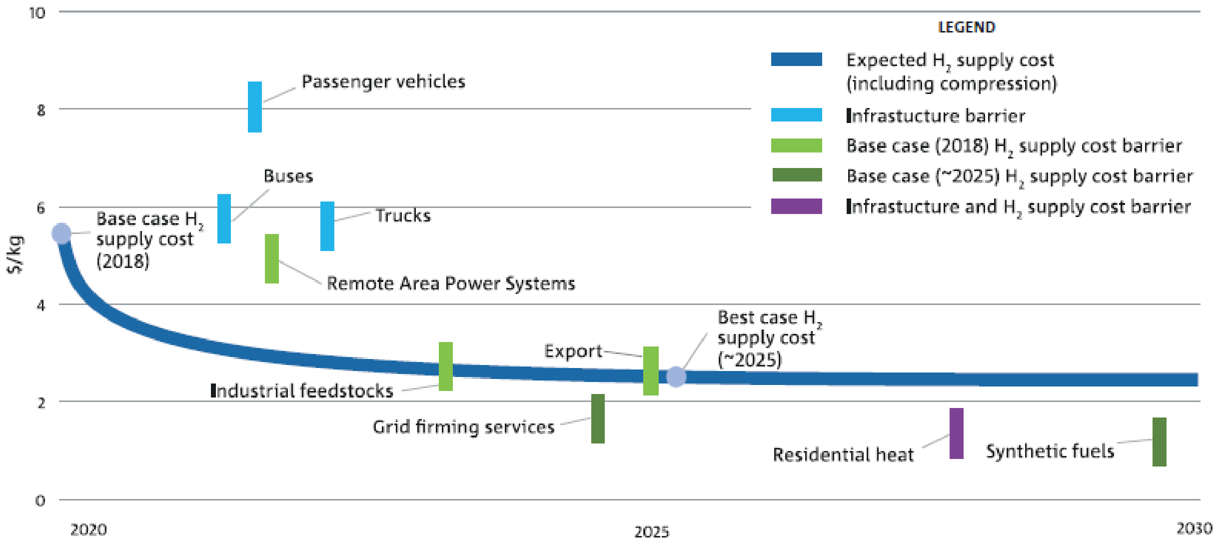


Figure 26: Hydrogen competitiveness in targeted applications in 2030 (CSIRO 2018)

Hydrogen systems can provide electricity grid stability (i.e. seconds to hourly storage) and grid reliability (i.e. seasonal storage) services. Hydrogen fuelled transport represents an early target market in the development of a hydrogen industry. In the passenger vehicle market, full cell electric vehicles (FCEV) represents a potentially more favourable option (compared to battery electric vehicles (BEVs) for consumers that travel longer distances (i.e. 400km-600km without refuelling) and expect shorter refuelling times. Direct combustion of hydrogen to generate heat is unlikely to compete with natural gas on a commercial basis before 2030 (CSIRO 2018).

The use of clean hydrogen as an industrial feedstock involves direct displacement of hydrogen derived from SMR as the incumbent production source. The breakeven point will be driven by the natural gas price against reductions in the cost of hydrogen via electrolysis. That is expected to occur before 2025. Thus, there is less that must be done in terms of market activation other than incentivising clean hydrogen in these processes before it is commercially competitive. Synthetic fuels are unlikely to compete with crude derived fuels on a purely commercial basis (CSIRO 2018).

Export of hydrogen represents Australia's key opportunity for energy and industrial feedstock supply (CSIRO 2018).

Further, CSIRO analysed the community knowledge required to ensure stakeholders understand all aspects of hydrogen use. Along the value chain from supply and application of hydrogen, stakeholder and communities have to be engaged in the development process (CSIRO 2018).

Table 18: Overview hydrogen use for energy supply and industrial feedstock (CSIRO 2018)

Energy	**Hydrogen use**
Stationary electricity	Storage of variable renewable energy, (power-to-gas), generate electricity from reverse electrolysis with fuel cell and from combustion with turbines
Electricity grid firming	Storage of variable renewable energy, generate gas turbines for energy peak demand
Hydrogen fuelled transport	Passenger fuel cell electric vehicles powered by fuel cell and hydrogen storage tank Hydrogen refuelling stations Material handling including forklifts, narrow aisle lift trucks, pallets jacks
Heat	Residential appliances including boiler, cooktop, grill/oven, gas heating Industrial appliances including furnace/kilns, boilers and combined heat and power
Export	Export of clean hydrogen for energy applications
(Industrial) Feedstock	**Hydrogen use**
Petrochemicals	Hydrotreating and hydrocracking for the treatment for biofuels
Synthetic fuels	Syngas or power-to-liquid for liquid fuel supply
Chemicals, Ammonia	Ammonia, ethanol & olefins derived from clean hydrogen for fertiliser and chemicals
Food	Catalytic hydrogenation to harden oil for margarine production and baking
Glass manufacturing	In combination with nitrogen to prevent oxidation and flaws in glass
Metals processing	Production from iron ore to steel, reduction of ore (removal of oxygen)
Export	Export of green industrial feedstock produced with clean hydrogen

Gas infrastructure

The competitiveness of hydrogen against other technologies depends on the existing infrastructure. Hydrogen production costs can be improved by considering localisation and automation of supply chains, energy supply, carbon risk and hydrogen export opportunities. The utilisation of existing infrastructure where possible is preferred (CSIRO 2018).

Hydrogen supply and demand: A proximate source of hydrogen supply is critical to assessing a particular site's suitability. Areas that have strong solar or wind resources for energy input would be most favourable greenfield sites with new building developments that have flexibility in designing and implementing appliances would also be preferred. Further, there may be an opportunity to combine hydrogen capable appliances and infrastructure as part of a broader smart cities' initiative.

Existing infrastructure: Existing pipeline infrastructure that can accommodate a pure hydrogen gas stream, or require minimal upgrades, would be preferred over building a new pipeline. If required, upgrading or reinforcing pipeline infrastructure to support gas usage across a residential network is commonplace in Australia. Upgrades to the network tend to occur incrementally, with the bulk of construction undertaken during the summer months when gas demand is lower. Customers with a need for continuous gas supply would likely be accommodated by either using portable tanks or by front loading gas downstream and sealing off a pipeline.

Hydrogen storage: Depending on the demand profile, large-scale hydrogen storage may be needed to accommodate inter-seasonal variation. In the more immediate term, pressurised storage tanks are likely to be sufficient. However, there may be a longer-term need to identify and situate a pilot city alongside salt caverns or potentially depleted gas reservoirs.

Pathway 9: Hydrogen Council 2017 & 2020

In 2017, the Hydrogen Council developed their first Hydrogen strategy, which was updated with a cost analysis in 2020. The Hydrogen Council is a global initiative of energy-intensive companies from energy, transport, and industry.

Modelling

To develop their vision and roadmap, the Hydrogen Council used two primary sources: the IEA Energy Technology Perspective (2017), which projects final energy demand in the transport, industry, building, and power sectors under the two-degree scenario as well as the Hydrogen Council members' input on the potential for hydrogen adoption in each sector (Hydrogen Council 2017). No quantification of the vision is included.

ESE assessment

The vision of the Hydrogen Council describes the deployment of clean hydrogen to reach the decarbonisation of the global energy system by 2050, see Figure 27. Hydrogen deployment delivers deep decarbonisation of transport, industry, and buildings and enables a renewable energy production and distribution system by 2050. Hydrogen is not seen as the single solution to all problems but as an enabler to reduce overall emissions (Hydrogen Council 2017).

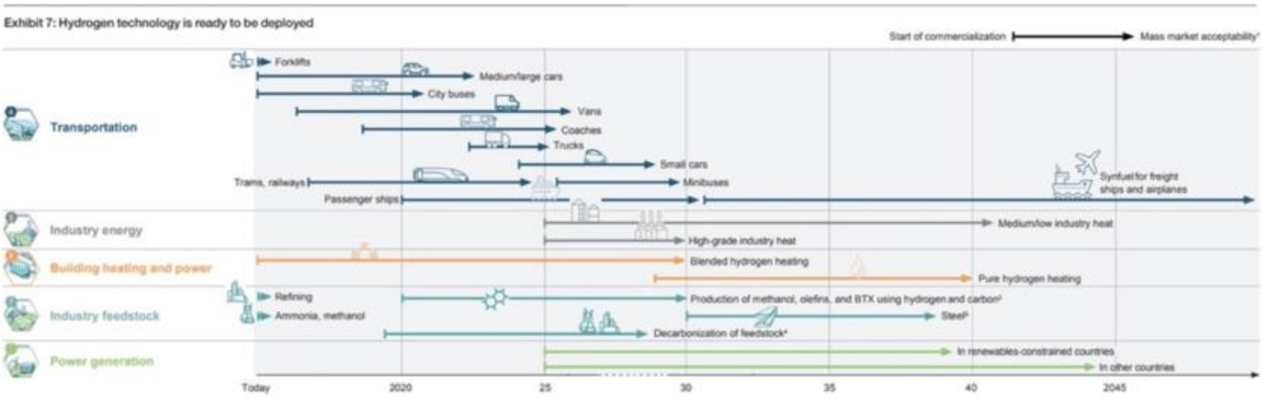
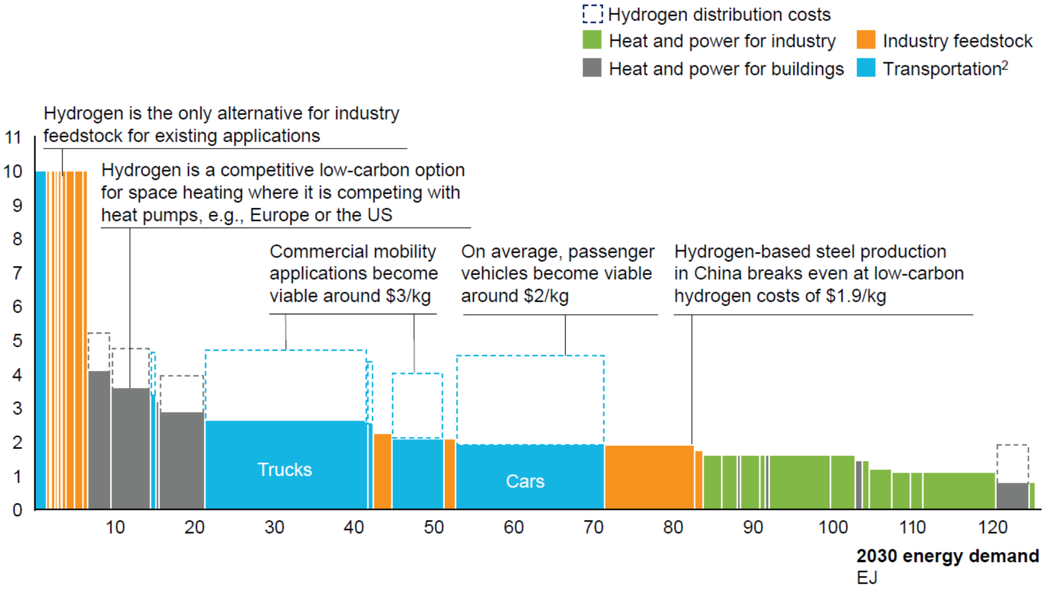


Figure 27: Hydrogen technology is ready to be deployed (Hydrogen Council 2017)

The roadmap details the role that hydrogen will play in each application and the required medium-term milestones, investments, and deployment initiatives (Hydrogen Council 2017). Figure 28 shows breakeven hydrogen costs at which hydrogen application becomes competitive against low carbon alternatives in a given segment (Hydrogen Council 2020).



1. Regions assessed are the US, China, Japan/Korea, and Europe
2. Transportation segments breakeven calculated as weighted average

SOURCE: McKinsey; IHS; expert interviews; DoE; IEA

Figure 28: Cost curve for hydrogen production across segments and regions in USD (Hydrogen Council 2020)

In the transportation sector, hydrogen fuel cell electric vehicles (FCEVs) could complement battery electric vehicles (BEVs) to achieve deep decarbonisation of all transportation segments. FCEVs are best suited for applications with long-range requirements, heavier payloads, and a high need for flexibility like trucks, coaches, and vans. FCEV buses, medium-sized cars, and forklifts are commercially available today. The next five years will see more models in medium-sized and large cars, buses, trucks, vans, and trains, and it is likely that additional segments such as smaller cars and minibuses will follow until 2030. Hydrogen Council expects all transportation segments to be within a 10% range by 2030, which requires a significant scale-up of manufacturing capacities. If realized, FCEVs would have lower investment costs than BEVs in long-range segments, with much shorter refuelling times. Environmentally, FCEVs emit very little CO_2 and require fewer resources and energy in the manufacturing process than BEVs. Towards 2050, the vision also includes hydrogen as a feedstock for renewable fuels for commercial aviation and freight shipping (Hydrogen Council 2017).

For heat and power in buildings and industry, hydrogen can use existing gas infrastructure and assets. For buildings, low concentrations of green hydrogen could be blended into public natural gas networks without infrastructure upgrades. Alternatively, entire cities could be converted to pure hydrogen heating. Both processes have already started and could start scaling up around 2030. The second wave of commercialisation could start once the costs of producing hydrogen have fallen enough to drive uptake in more cost-sensitive industry segments. While hydrogen penetration may not reach the same rates in the industry as in other segments, industry's large energy consumption implies substantial hydrogen demand beyond 2050 (Hydrogen Council 2017).

Large amounts of cost competitive hydrogen are already used as feedstock for refining and the production of methanol. Decarbonisation of these processes starts, and production cost of electrolysis reduces, the first oil refineries and ammonia plants could produce hydrogen from clean sources in 2030. If CCS projects have proven viable, hydrogen could be used together with CCS to replace fossil fuels as feedstock for the chemical industry. In the iron and steel industry, where hydrogen can be used to reduce iron ore to iron, the expected use of clean hydrogen will be demonstrated by 2030 and gain momentum by 2035 (Hydrogen Council 2017).

Gas infrastructure

Hydrogen is most attractive in countries that already have an extensive natural gas infrastructure (Hydrogen Council 2017):

- Hydrogen can make use of existing natural gas infrastructure and equipment. It can therefore be less expensive than other approaches, such as electrification pathways. Investments to upgrade gas infrastructure or convert gas appliances are minor compared to a full switch from gas to electric.
- Unlike electricity, hydrogen is easy to store for long periods. That is relevant as heating demand is highly seasonal. A large share of electrical heating would create a strong seasonal variation in demand for power, which would require extensive additional renewable capacity that will be used only in winter. With hydrogen, a lower amount of renewable capacity could produce and store hydrogen throughout the year.
- Converting to hydrogen heating may be more convenient than full electrification. No extra space or rewiring is needed to install new heating equipment, and no adjustments to heating patterns need to be made. That is in contrast installing air-sourced electric heat pumps, which require space – often not available in densely populated urban areas – and offer no on-demand heat or hot water.

Hydrogen can be used to decarbonise the natural gas grid in three ways: it can be blended with natural gas, converted to methane, or used in its pure form (Hydrogen Council 2017):

- Low percentages of hydrogen can be safely blended into existing gas networks without major adaptations to infrastructure or appliances. Depending on the pipeline network system and the local natural gas composition, hydrogen can make up 5%- 20% of the volume content of the natural gas supply.
- Hydrogen can also be converted into methane through a process called methanation. That requires a CO2 source and energy for the conversion, leading to lower efficiency of about 20% compared to direct blending and creating additional costs. The advantage is that the resulting substitute or SNG is pure methane and hence fully compatible with the existing natural gas networks and storage infrastructure as well as all appliances.
- Pure hydrogen networks are possible if infrastructure and appliances are upgraded accordingly. Leakage control needs to be improved, and any remaining steel pipelines need to be retrofitted or replaced with noncorrosive and nonpermeable materials, such as polyethylene or fibre-reinforced polymers. However, old pipelines are being replaced independently of a hydrogen transition, limiting the need for additional investment. Appliances, including ovens and stoves, boilers, and hot water tanks, would need to be converted or replaced.

2.3.5 Spatial analysis

The spatial analysis uses topographical, geometric, and geographic data to develop maps with characteristic properties.

Pathway 10: Geoscience Australia 2019

Geoscience Australia has been engaged by the Department of Industry, Innovation and Science (now DISER) to develop maps that show prospective hydrogen production regions of Australia. The maps inform Australia's National Hydrogen strategy. Data input is based on publicly available sources.

Modelling

Geoscience Australia's spatial analysis uses geographic properties to develop five different maps that reflect key differences in technologies for hydrogen production and the requirements of those technologies.

Three maps explore the future potential for renewable hydrogen produced by electrolysis. These demonstrate a high potential for hydrogen production in the future near many Australian coastal areas, which is even larger if the infrastructure is available to transport renewable power generated from inland areas to the coast. Results also show significant future potential for hydrogen production in inland areas where water is available.

Two maps focus on the future potential for CCS hydrogen: a 2030 scenario and a 2050 scenario. A key factor in future CCS hydrogen potential is related to the timeframes for the availability of geological storage resources for CO2.

ESE assessment

Australia has extensive fossil fuel resources that can be used with CCS to produce hydrogen with low carbon emissions. The potential increases significantly when additional CCS sites, which are expected to become available over time, are incorporated into the analysis. For inland CCS hydrogen, access to groundwater or competition for reservoir pore space may be a limiting factor. It is recommended to take a holistic view of hydrogen generation in these regions and explore mutually beneficial arrangements for the oil and gas industry, agricultural water users, town water supplies and hydrogen generation (Geoscience Australia 2019).

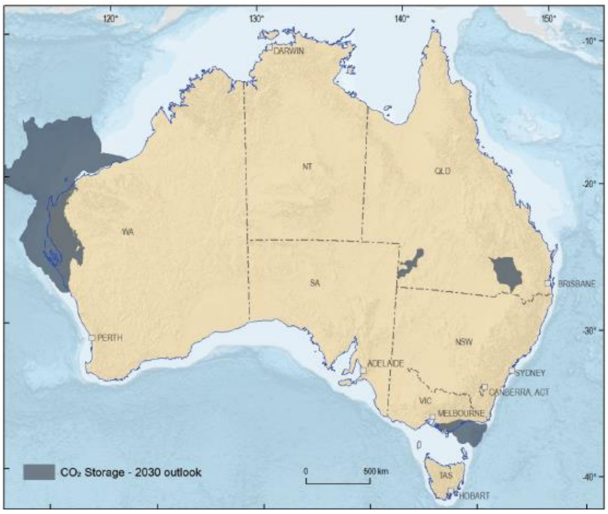


Figure 29: 2030 potential CO_2 storage sites that are at an advanced stage of characterisation and/or development. Note the lateral extent of the most suitable reservoirs for CO_2 storage within the Carnarvon Basin in WA is uncertain

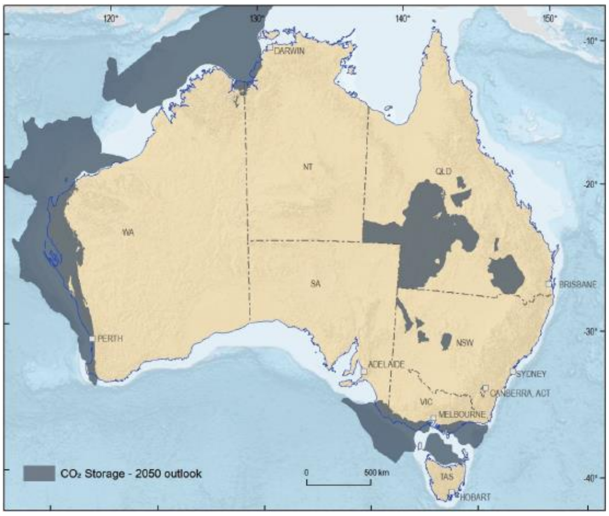


Figure 30: 2050 longer term outlook for CO_2 storage sites There is highly likely to be storage potential in South Australia in the Cooper Basin (e.g. Moomba) but it has not been recently mapped

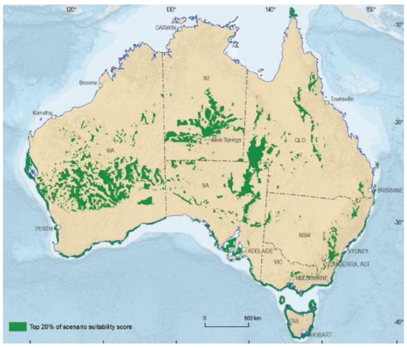


Figure 31: Scenario 1
Top 20 percent of the most prospective renewable areas (Renewable resource potential - unconstrained).
The areas highlighted in green cover a total area of 872 760 km^2

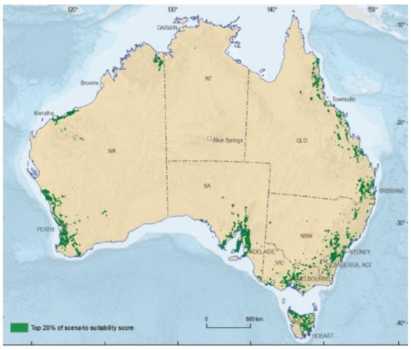


Figure 32: Scenario 2
Top 20 percent of the most prospective areas (Renewable Hydrogen; coastal production and constrained by existing infrastructure).
The areas highlighted in green cover a total area of 261 755 km^2

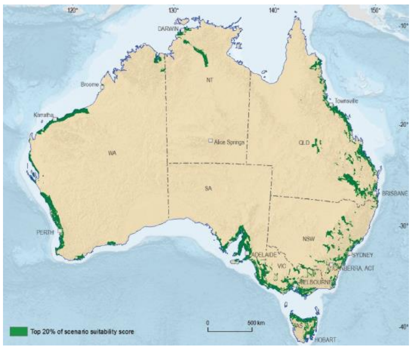


Figure 33: Scenario 3
Top 20 percent of the most prospective areas (Renewable Hydrogen; coastal or inland production, pipeline transport and constrained by existing infrastructure).
The areas highlighted in green cover a total area of 350 287 km^2

Gas infrastructure

The report shows the importance of additional infrastructure and technology development to unlock Australia’s hydrogen resource potential. Many areas may only become suitable if additional infrastructure investments can improve the connection between the coast and inland areas that possess efficient renewable energy potential. The development of other geological storage sites and the CCS industry, in general, will be required to enable the rapid acceleration of CCS hydrogen production.

CCS hydrogen is highly prospective in Victoria using brown coal or gas due to the co-location of fossil fuels, a big storage reservoir, access to water and good infrastructures like ports, pipeline easements and electricity networks. Brown coal is well suited to hydrogen production due to its higher moisture content. The geological storage capacity for the Gippsland Basin is very large and is estimated to be over 30 000 Mt of carbon dioxide (Geoscience Australia 2019).

2.4 Role of government

This section presents policy recommendations identified in literature from academia, industry, and think-tanks. A brief overview of current government actions to decarbonise gas infrastructure follows.

2.4.1 Literature overview

The literature review identifies recommendations for decarbonisation policies, implementation strategies for hydrogen and biogas, and a regulatory review to inject hydrogen and biogas into the gas networks. The recommendations do not focus on Victoria but Australia in general.

Decarbonisation policy

The Grattan Institute identifies three actions to reform Australia's energy policy to cut carbon emissions to near zero over the next 30 years:

1. energy policy must be integrated with carbon policy, encompassing transport, industrial, and export energy.
2. COAG should negotiate a new Australian Energy Agreement (AEA) to drive decarbonisation in stationary, transport, industrial, and export energy.
3. institutional agencies need to be strengthened to implement the policies determined by governments (Grattan Institute 2019).

Emissions reduction requires action by government, businesses, and individuals. Government policies can drive emissions reduction through legislation, regulation, and incentives (for example, renewable energy targets, vehicle emissions standards, direct procurement, investment in climate solutions).
Governments can also provide essential infrastructure to support the rollout of technologies and solutions (such as investments in electricity transmission, EV charging infrastructure, biogas, hydrogen, and CCS), and reduce non-price barriers to their adoption (for example, by providing consumer information and requiring companies to disclose climate strategies and actions). (ClimateWorks Australia 2020a).

Consultants Energetics', engaged by Energy Networks Australia (ENA), identify that the Australia's current policy measures will not be enough to achieve net zero emissions of gas infrastructure by 2050. To close the policy gap the paper makes the following policy recommendations (Energetics 2019):

- Establish a near-term aspirational target for cost-effective renewable gas injection into the gas networks by 2030.
- Establish a method for creating Australian Carbon Credit Units for projects that inject renewable gas into the existing gas transmission and distribution infrastructure.
- Entrench a best practice regulatory framework for hydrogen and biogas production, storage, and use, including a health, safety, design, and metering standard for hydrogen.
- Build on the existing momentum at federal and state levels to develop a hydrogen economy to explore options for domestic use of hydrogen using existing infrastructure for distribution of the gas, the use of hydrogen as a transport fuel, and the export of hydrogen.

Both Frontier Economics and Deloitte Access Economics conclude in their analyses that the sustainable gas scenario is lower cost than the electrification scenario. They conclude that decarbonisation policy needs to appropriately support a broad range of options and technologies without narrowing the set of options available to consumers. Government should take the lead role in supporting investment in early-stage research and development and demonstration, and early-stage commercialisation (Deloitte Access Economics 2017). Therefore, policies to achieve net zero emissions should be broad-based and should not focus solely on promoting electrification of all stationary energy end-use. That will enable private investment to respond flexibly to technology and cost changes to lower costs (Frontier Economics 2020b). Both were engaged by ENA.

Finally, ENA concludes that policy must focus on the following key activities to convert gas networks in the 2030s to hydrogen and biogas (Energy Networks Australia 2019):

- develop a certification scheme for low carbon biogas and hydrogen, allowing it to be recognised and traded as an emission free product
- establish blending and technology targets
- establish zero emissions gas contracting arrangements – like power purchase agreements for electricity – to create a market for hydrogen and biogas
- scale up low carbon gas production by blending in networks, leading to significant cost reductions that will ensure the entire network's conversion to zero emissions gas
- continue research and development of new technologies or applications of existing technologies to accelerate emissions reductions
- demonstrate the safe use of hydrogen in appliances

- share lessons from the diverse range of demonstration projects underway and use these to inform market and policy settings
- in conjunction with the broader industry, undertake large-scale demonstration of transformational technologies to test and showcase their emission reduction potential
- deploy transformational technologies in early commercial stage.

The next question is to understand how and where policy recommendations for hydrogen and biogas differ.

Hydrogen strategy

Since 2018, numerous countries have begun to develop hydrogen strategies to achieve decarbonisation and energy security goals. The policies aim to remove barriers to commercialisation and drive hydrogen investment. Policy measures include funding mechanisms, targets for use of hydrogen, new regulation, subsidy mechanisms, creation of investment funds, and tax credit schemes.
Australia must develop a clear policy and targets to drive the use of hydrogen, establishing itself as a global leader in order to help secure long-term private investment and create export opportunities. Other barriers for the industry include missing regulations, standards, and acceptance (Deloitte 2019).

Government policies and regulatory settings must support industry growth. The COAG Energy Council supports foreign investment to build up large-scale export industries. Therefore, hydrogen expertise must be developed. COAG Energy Council recommends establishing hubs for the early-stage demonstration of hydrogen that will increase sector-coupling value and reduce total infrastructure costs. That includes developing standards for the hydrogen industry and community education programs to improve knowledge and engagement. Shared, nationally consistent regulation principles would support a collaborative, focused, flexible, and innovative approach (COAG Energy Council 2019).

In the context of hydrogen exports, Australia could play a leading role in designing and developing an international guarantee of origin scheme. This scheme would identify production technology, carbon emissions associated with hydrogen production, and production location (CSIRO 2018) (COAG Energy Council 2019).

CSIRO expects that the development of a policy framework creates a ‘market pull’ for hydrogen. Private and public investment along the value chain of hydrogen production, storage and transport are likely to follow. However, the gas pipeline regulation to allow hydrogen injection must be reviewed (CSIRO 2018).

The Victorian Government, through DELWP, engaged GHD Advisory and ACIL Alen Consulting to assess possible future hydrogen production impacts on Australian power systems. The report analyses the value of sector-coupling of hydrogen with power systems, whether relevant electricity system regulatory frameworks are compatible with industrial-scale hydrogen production, and the use of hydrogen for power generation. The report finds policy should (GHD Advisory & ACIL Allen 2020):

- Make changes to the regulatory approval process for network expenditure to ensure responsiveness to rapid changes to emerging hydrogen.
- Understand and monitor the energy markets’ interdependencies (e.g., increased demand for gas-fired power plants).
- Build national skill capabilities ahead of potentially significant market changes.
- Recognise and facilitate hydrogen pilot projects as short-term activities that enable longer-term insights and benefits for the energy industry.
- Create an environment that brings greater transparency and certainty over future electricity prices to promote longer-term investment solutions.

Biogas strategy

Deloitte Access Economics, engaged by ENA, conclude that supplying a significant proportion of gas demand through biogas is technically achievable. However, this would require a significant shift in energy policy to provide long-term price signals to incentivise bioenergy crops and produce sufficient volumes of biogas (Deloitte Access Economics 2017).

The policy recommendations for hydrogen can also be applied to biogas. Nevertheless, there are minor differences. ENEA Consulting, engaged by Bioenergy Australia, makes the following policy recommendations for biogas (ENEA Consulting 2019):

- Set renewable gas target(s)
- Launch industry stakeholder consultation for policy design
- Introduce waste management strategies to support feedstock quality and quantity
- Encourage plant operators, especially landfill operators, to maximise biogas use
- Explore opportunities for the transport sector
- Provide regulatory clarity for digestate
- Simplify approval processes
- Inform the community about biogas and its benefits.

Injection of hydrogen and biogas

The injection of hydrogen and biogas into natural gas pipelines requires further regulatory review. However, several publications have reviewed existing regulations to enable hydrogen and biogas injection into the natural gas grid.

A legal report developed for Energy Networks Australia outlines whether it is permissible to inject hydrogen and biogas into existing gas distribution networks in each jurisdiction in Australia and to what extent. According to the National Gas Law or the National Gas Rules, some of the key findings include the injection of hydrogen and biogas is permitted. According to the *Victorian Gas Industry Act 2001* or the *Gas Safety Act 1997*, the injection of hydrogen and biogas is conditional; and permitted under *Gas Safety (Gas Quality) Regulations 2007* and *Gas Safety (Gas Installation) Regulations 2008* (Johnson Winter & Slattery Lawyers 2018). Safety standards for pipelines and appliances need to be reviewed.

Clayton Utz, engaged by COAG Energy Council, examines the laws relevant to developing a national hydrogen industry in Australia. The report reviews Commonwealth, state, and territory legislation, regulations, and standards that could be relevant to hydrogen projects and industrial development. It includes recommendations on how to proceed with an in-depth legal review such as the prioritisation of reviewing and developing law in respect of safety standards; establishing a project group to coordinate national consistency; and preparing a “Regulatory Development Timeline” to include the development of regulatory responses and new law (or amendments to existing Law) (Clayton Utz 2019).

Oakley Greenwood was also engaged by Energy Networks Australia to examine the injection of renewable gas options and their legal barriers in Australia. The consultants developed a Renewable Gas Blending Scheme to incentivise the blending of all renewable gases like biogas and hydrogen into Australia’s gas networks. A certificate-style scheme is conceptually likely to be most appropriate. The scheme considers potential design options, certificates surrender, liability issues, eligibility, and target setting (Oakley Greenwood 2019).

2.4.2 Government actions

It is still uncertain what pathway Australia will choose to decarbonise gas infrastructure by 2050.

In the short to mid-term, Australian governments are further investing in natural gas infrastructure. Recently, the Prime Minister of Australia announced a gas-led recovery from COVID-19. Scott Morrison said, “the government will reset the east coast gas market and create a more competitive and transparent Australian Gas Hub by unlocking gas supply, delivering an efficient pipeline and transportation market, and empowering gas customers” (Prime Minister of Australia, The Hon Scott Morrison MP 2020). This approach is at odds with many of the cited studies as it increases the risk of natural gas infrastructure becoming stranded assets for Australia. However, Australian regulators, the Commonwealth, and state governments are taking the first steps to support new technologies long-term.

AEMO will continue to monitor the use of existing of gas networks with biogas and hydrogen to deliver low carbon energy. However, these technologies are not expected to materially impact Victorian supply and demand during the outlook period until 2024 (AEMO 2020b). The VGPR 2021 notes Victoria’s transition to a lower emissions future: one that needs to balance current investments to prevent short-term shortfalls but also avoid long-term stranded natural gas assets (AEMO 2021b).

The Australian Energy Regulator (AER) supports trialling hydrogen production from renewable energy for injection into the network. Once the projects are economically successful, natural gas networks could be re-purposed to distribute hydrogen (AER 2020).

The Department of Industry, Science, Energy and Resources (DISER) presents a vision for Australia as a global low emissions technology leader in its *Low Emissions Technology Discussion Paper*. The paper aims to guide strategic and system-wide future investments in low emissions technologies. Electrification, low or zero emissions gases, such as hydrogen or biomethane, combined with CCS, could gradually replace natural gas for some uses while utilising aspects of existing gas infrastructure. However, these will likely require substantial investments to develop industries and technology (DISER 2020c). The paper prioritises five low emissions technologies with the potential to deliver the most substantial economic benefits and emissions reduction outcomes. The “first priority technology stretch goals” include *H2 under AUD $2*, *CCS with* CO_2 *compression, hub transport and storage under $20 per tonne of* CO_2, and *soil carbon measurement under AUD $3 per hectare per year* (DISER 2020d).

The Clean Energy Finance Corporation (CEFC) is the body for the Australian Government's investment in new and emerging technologies. The corporation has received funding of more than AUD $1 billion to 30 June 2020. The Advancing Hydrogen Fund received AUD $300 million and bioenergy and waste AUD $147.5 million financial support. The *CEFC Act 2012* excludes investment in carbon capture and storage (and nuclear technology and nuclear power) because they are not yet energy efficient, renewable, or low emission technologies (CEFC 2020). There were proposals to include funding for CCS that have been declined. The CEFC understands CCS as a challenging technology with elevated construction, implementation, and economic risks (CEFC 2018).

Hydrogen, however, has received considerable funding from the CEFC in the recent past. From 2015 to 2019, the Australian Government has committed over AUD $146 million to hydrogen projects along the supply chain, with

- $67.83 million for research and development
- $4.88 million for feasibility
- $5.04 million for demonstration, and
- $68.57 million for pilot projects (COAG Energy Council 2019).

The Australian Renewable Energy Agency (ARENA) funds innovations in renewable energy technologies. From 2012 to 2020, ARENA has invested in a total of AUD $131 million in bioenergy - with only one biogas demonstration project in Queensland (AUD $4.42 million) and one biomethane injection project in NSW (AUD $11.96 million). In Victoria, there are currently no funded projects for biogas or biomethane. From 2012 to 2020, ARENA funded AUD $57 million in hydrogen projects in Australia. In Victoria, five hydrogen projects have received funding of AUD $30.7 million. There are no funded projects for CCS in Australia (ARENA 2021b). ARENA is mainly funding research and development projects.

The Victorian Government has several strategies and programs to support its target of net zero emissions by 2050, Developed in 2016, the *New Energy Technologies Strategy* aims to drive the development of new technologies, jobs, and initiatives delivering energy from renewable sources (Victorian Government 2016). The strategy focuses only on emission reduction targets in the energy sector, mainly electricity generation. Biomethane, hydrogen, and CCS are not mentioned.

On addition, DELWP is developing a *Victorian Hydrogen Investment Program* incorporating expert feedback from industry, academics, and communities. The investment program will publish a strategy for the funding and investment support of green hydrogen technologies in Victoria (DEWLP 2021). However, the decarbonisation pathway for natural gas infrastructure is not yet decided. The Victorian Government has recognised this gap and is currently developing a gas roadmap, led by DELWP. Infrastructure Victoria will contribute to pathway development, through infrastructure advice it provides to government at the end of 2021.

Nevertheless, due to national strategies and roadmaps, there are several research and development projects for biomethane, hydrogen, and CCS in Victoria. Table 19 gives an overview of the most important hubs, demonstrations, trials, and pilot projects publicly and privately funded.

Table 19: trial projects in Victoria (ARENA 2021) (CSIRO 2018) (Global CCS Institute 2020)

Project	Location	Project Details	Stakeholders
Australian Hydrogen Centre (AHC)	VIC/SA	Feasibility assessment of blending renewable hydrogen into gas distribution networks in Victoria and South Australia	Australian Gas Networks, DELWP, AusNet Services, Engie Energy Services, Neoen Australia, ARENA
CarbonNet	Latrobe Valley & Gippsland offshore basin	Design of infrastructure for large-scale carbon capture and storage (CCS) network	DJPR
CO2CRC	Nirranda South	Research hub for carbon capture, utilisation, and storage (CCUS)	Industry: BHP, ExxonMobil, Shell etc. Commonwealth and Victoria State Government
Hydrogen Energy Supply Chain (HESC)	Latrobe Valley	Hydrogen liquefaction facility for transport and export to Japan	Kawasaki, J-Power, Iwatani, Marubeni, AGL, Sumitomo
Toyota Ecopark Hydrogen Demonstration project	Altona	Partial transformation of Toyota Australia's decommissioned car manufacturing plant in Altona into a renewable energy hub including electrolyser and hydrogen refuelling station and education centre to produce renewable hydrogen for stationary energy and transport energy use	Toyota, ARENA
Victorian Hydrogen Hub (VH2)	Clayton	Research hub to explore new hydrogen technologies, including clean energy vehicles and hydrogen storage containers	Swinburne University of Technology Victorian Hydrogen Hub, CSIRO, ARENA2036
Yarra Valley Water	Wollert	Operation of biogas plant from wastewater treatment Production of hydrogen via electrolysis to produce oxygen for efficient wastewater treatment	Yarra Valley Water

3. Conclusion

This conclusion summarises key findings identified in literature from academia, industry, think-tanks, and governments. The reviewed literature addresses the questions asked at the beginning to contribute to our understanding of the key risks and opportunities towards net zero emissions for gas infrastructure in Victoria.

3.1 Victorian gas infrastructure

This section will answer the question of what key risks and opportunities exist for natural gas transmission and distribution infrastructure to achieve net zero emissions in Victoria by 2050.

In 2018-19, Victoria had the third-largest energy consumption in Australia; 95% of which comes from fossil fuels. After oil and coal, gas is the third-largest energy consumption in Victoria (22%). In comparison with other Australian states, Victoria has the third largest gas consumption, including domestic use and export. Western Australia has the highest share of gas nationally, with a share of 42%, mainly due to its significant mining industry. Queensland natural gas use is at 18.4%, closely followed by Victoria with 17.8%.

Looking at energy production, natural gas is behind coal as Australia’s second-largest contributor to energy production with a share of 27.9%. Western Australia accounts for around 60% of Australian gas production, followed by Queensland (25%) and Victoria (9%). Most of Australia’s gas (72%) is exported as LNG. The remaining natural gas is used for gas-fired power generation (8.2%), manufacturing (6.6%), residential (3.0%), and mining (1.2%).

In Victoria, the forecasted shortfall in annual gas consumption in 2024 is prevented through new gas supply and declining demand. But more investments may be needed to improve annual natural gas supply and to prevent a later shortfall. Investments include sourcing new on- and off-shore gas and expanding pipelines and construction of LNG import terminals, such as that suggested by the *Victorian Gas Program*.

Victoria’s gas network infrastructure is over 30,000 kilometres and provides over 2 million end-users with gas. The immense size of Victoria’s gas infrastructure and the invested capital is a risk. By developing the climate targets and competing for renewable energy, Victorian gas infrastructure could become underutilised or stranded assets long before its useful life of 30 to 40 years.

The residential, manufacturing, electricity supply, and transport sectors account for nearly 90% of gas consumption in Victoria in 2018–19. Due to its colder climate, households in Victoria use much more gas than other states. After cooking and water heating, space heating is by far the most considerable use of natural gas, with a share of 74% in Victoria. As a result, Victorians consume almost half of Australia’s household gas consumption just for heating.

By 2018, wholesale gas prices rose from AUD $4 and AUD $6 per gigajoule to AUD $8 and AUD $10 per gigajoule for new gas contracts. Domestic gas prices were pushed by increased demand for Australian LNG from a larger and higher-priced international gas market, in particular Asia. To meet the demand, supply was increased by exploring more expensive gas sources, which pushed prices in the east coast market. If gas prices on Australia’s east coast, including Victoria, remain high compared to some overseas markets, this will lead to more supply risk. That leads to uncertainties for future cost trajectories and uncertainties around Victorian gas supply adequacy forecasts. Lower international prices could suppress domestic exploration and development expenditure, reducing the longer-term gas supply outlook.

Victoria is the third-largest contributor to Australia’s total net emissions (19%), behind Queensland (32% and NSW (25%) in 2018. However, Victoria has the third-highest emission reduction results after Tasmania (111%) and South Australia (31.6%), which have more ambitious climate and renewable energy generation targets. Natural gas emissions are only reported in the context of direct combustion and fugitive emissions. Natural gas is the major fuel used for direct combustion representing 62% of the total fuels used in Victoria in 2018, with the highest consumption in residential activities (38.7%), followed by manufacturing (20.7%) and commercial (12.6%) activities. Almost 61.0% of fugitive emissions in Victoria arise from leakage of gases during the exploration, production, transmission, storage, and distribution of natural gas. However, fugitive emissions are controversial. The emissions might be underestimated, and natural gas’s negative climate effect might be even more significant.

Victoria’s gas infrastructure reveals several opportunities that can be leveraged, in addition to a series of risks that need to be addressed, refer to Table 20.

Table 20: Summary of opportunities and risks of Victorian gas infrastructure found in literature

Opportunities	Risks
Unexplored coal and natural gas resources Extensive natural gas networks 2 million natural gas end-users Stronger trade position of LNG terminals Decommissioning of coal-fired power plants, firming role of natural gas fired electricity Falling technology costs of renewables, batteries, and energy efficiency Moderate total emissions reductions	Shortfall meeting natural gas demand from 2024 High-cost environment for gas infrastructure High residential natural gas consumption for space heating Underutilised or stranded assets of natural gas infrastructure Social licence to operate LNG import terminal Increasing wholesale prices of natural gas Missing Paris climate goals of net zero by 2050 and experiencing significant climate change impacts High, underestimated fugitive emissions from natural gas

3.2 Decarbonisation technologies

This section will answer the key risks and opportunities for the natural infrastructure to achieve net zero emissions in Victoria by 2050, mainly to hydrogen, biomethane, and carbon capture and storage (CCS). That includes the technical and commercial maturity of those pathways.

If gas infrastructure is to secure its role in a low-emissions system, it will need to deliver low carbon energy sources. There are several reasons to decarbonise Victorian gas infrastructure. One recent argument is the opportunity for economic recovery from COVID-19 through the decarbonisation of energy systems. Government stimulus spending on renewable energy like wind, solar, bioenergy, and energy efficiency creates more jobs than fossil fuels like oil, coal, and natural gas.

The most apparent reason for decarbonisation is the climate risk of natural gas. Methane emissions produced by natural gas might be underestimated. Primarily, there are uncertainties around fugitive emissions from the production and transport of natural gas. Extending fossil combustion by switching from coal to gas will cause further emissions that risk achieving climate targets in 2050. Further, there are risks of the global gas and LNG infrastructure becoming underutilised or stranded assets before their end of life of 30 to 40 years.

Some research has been done on decarbonisation pathways for Australian gas infrastructure. However, most of the work only focuses on cost benefits analysis of different scenarios in 2050. Most of the work was commissioned by Energy Networks Australia (ENA) and is therefore presumably focused on extending natural gas infrastructure. In this context, zero emission gases biomethane, hydrogen, and carbon offsets with CCS have been identified as crucial transformational technologies.

Many of the identified publications in this literature review deal with hydrogen only. Hydrogen can be utilised as an energy supply and industrial feedstocks. Hydrogen can be produced from water in three different processes. Currently, steam methane reforming (SMR) and gasification (producing grey and brown hydrogen) are the most common processes. Both technologies already have a high technical maturity and produce hydrogen at low costs. Using the input fuels, natural gas, or coal, both production methods are highly polluting, which conflicts with emission reduction targets. Carbon emissions during the SMR and gasification process must be captured and stored via CCS.

The electrolysis process extracts hydrogen from water using electricity. If renewable electricity is used, electrolysis produces no emissions. Electrolysis is still an emerging technology, that produces hydrogen at a high cost and with a high amount of energy as input. Depending on the investment level in research and development, electrolysis has the highest efficiency growth potential to produce low cost, zero emission hydrogen in the future. Hydrogen can be stored compressed as gas and liquid, and transported by pipeline, truck, ship, or rail.

There are several hydrogen strategies and roadmaps on international, national, and regional levels. The identified literature deal with hydrogen export, transport, co-location with water utilities, hydrogen as a chemical feedstock, and its public acceptance.

Australia is in a good competitive position to become a hydrogen exporter. Thirty potential domestic and export hydrogen hubs have been identified in Australia. In Victoria, the six potential sites are in Altona, Port Anthony, Port of Hastings, Port of Melbourne, Port of Geelong, and Portland.

Most of the work focuses on the impacts of hydrogen in distribution networks. A gas fuel mix of 10% hydrogen can be injected into gas distribution pipelines without the need for pipelines or appliance upgrades. Hydrogen cannot be injected into transmission networks because of the embrittlement of the steel pipelines. Further work must be done for transmission networks.

Hydrogen presents an alternative fuel in the transport sector. Benefits are improved fuel security within Australia, better air quality, and no emissions. The risks and barriers include the consideration of fuel and refuelling infrastructure, limited supply, and availability of fuel cell vehicles (FCEV) in Australia, and high cost competitiveness of FCEVs and alternatives such as battery electric vehicles (BEV). Because FCEVs are likely to be more costly than BEVs, hydrogen is a more viable fuel solution for specific applications like heavy vehicles or a storage method for renewable energy beyond the transport sector.

Water utilities could play a pivotal role in accelerating the development of Australia's hydrogen industry. Co-locating sustainable hydrogen production with some types of oxygen-based treatments at wastewater treatment plans (WWTP) could bring wider economic and social benefits and improve the prospects of developing hydrogen hubs.

At the moment, hydrogen is largely demanded as input for refining ammonia for the chemical production of fertilisers and explosives. Ammonia provides an early pathway for hydrogen industry development and can be leveraged to develop infrastructure and demand for other use cases.

Ongoing research on understanding and acceptance of hydrogen production and consumption by the public needs to be undertaken.

The minority of the identified publications deal with biogas or biomethane. The focus of current research is more general on bioenergy or biomass than biogas. Biogas is a renewable, reliable, and local source of energy. Biogas' combustion can be used as a source of energy for heat and/or electricity generation. Biogas can also be purified and upgraded to biomethane, which is similar to natural gas and can be injected into the natural gas grid without any changes in transmission and distribution infrastructure or end-user appliances. However, there is a lot of uncertainty regarding both the biomass resources' size and composition around Australia. For biogas, the opportunity depends on the availability of resources, but there is competition for those resources with other industries. The biogas industry provides an alternative route for waste treatment while contributing to the development of local economies. An opportunity is to co-locate biogas plants with existing wastewater treatment plants and residential, commercial, and industrial food and garden organic waste facilities to recover some organic material energy.

Many of the identified publications in this literature review only mention CCS in the context of hydrogen usage. However, there is not much further explanation or detailed analysis. Carbon can be stored in depleted oil and gas fields or saline formations. Carbon capture is more cost-effective to produce low-emissions hydrogen because carbon emissions are easier to capture during the hydrogen production process than to capture emissions from coal and natural gas combustion. If carbon is captured, it needs to be transported via pipelines to the final storage location. Therefore, it is more efficient to have CO_2 separation and storage close together. Australia and, in particular Victoria, is geographically well situated to store large carbon capacities. There is much certainty around suitable CCS locations. However, the technical and economic viability of CCS projects is still uncertain because most projects are still in development.

Table 21: Summary of opportunities and risks of decarbonisation technologies found in literature

Opportunities	Risks
Economic recovery with government stimulus spending on renewable energy Significant hydrogen production capabilities with renewables, natural gas and coal, world-leading hydrogen export Zero emissions hydrogen with electrolysis or CCS carbon offset Low production cost for SMR and gasification hydrogen Biogas renewable, reliable, and local energy source Repurposing gas network for carbon or renewable gas transport CCS carbon offsets for hard to abate industries Large CCS capabilities	Extension of fossil fuel-based industry locks in high emissions and Victoria unable to achieve climate change targets High production costs of electrolysis hydrogen Upgrades of gas pipelines required for injection of hydrogen Under-utilised biogas potential, feedstock use competes with other industries Gas network as a stranded asset Regulatory change required to enable injection of renewable gas into the grid Financial feasibility of CCS

3.3 Analysis of decarbonisation pathways

This section will answer the questions, what pathways have been proposed to replace the energy and chemical uses of natural gas. That will include the modelling that has been conducted to understand the economic, social and environmental (ESE) costs and benefits, including key assumptions and conclusions of the transition to net zero emissions for the gas sector in Victoria. To identify feasible options for the pathways, the selection of literature is based on publications that contain the development of

- scenario planning,
- cost benefit analysis,
- energy system modelling,
- roadmap or strategy development,
- and spatial analysis.

Nine pathways are presented in the combined context of energy and chemical use. There is one pathway in the context of energy use. Moreover, there is no pathway in the context of chemical uses, suggesting a research gap for analysis of replacement of natural gas as an industrial feedstock. The analysis of pathways looks at the used modelling, ESE assessment, and implications for the gas infrastructure.

Energy Networks Australia (ENA) and Energy Safe Victoria have chosen a scenario development where a possible energy future is described. The pathways are a purely qualitative approach. There is no detailed analysis or quantification of assumptions. Despite this, both pathways recognise a transition to a decarbonised economy by 2050 and describe a low or zero emission gas scenario. ENA engaged consultants to do a detailed cost benefit analysis of the scenarios.

Frontier Economics and Deloitte Access analyse gas distribution networks' decarbonisation using biogas, hydrogen, and CSS to deliver zero carbon energy. ENA engaged both works, presumably with the objective of identifying a viable lower-emissions future for the distribution network. The analyses suggest a variety of decarbonised gas options that are likely to be cost competitive with electrification over the long term. As the sustainable gas scenarios have lower costs than electrification, there is a value to continued use of the Australian gas network. Also, gaseous fuels are essential as industrial feedstock in all scenarios. With the help of Deloitte, AGIG concludes in the cost analysis that the use of hydrogen is 40% less expensive than full electrification for energy generation in Victoria.

Deloitte and ClimateWorks employ scenarios to analyse ecological, technical, and economic assumptions in their energy system modelling. COAG Energy Council engaged Deloitte to model possible policy scenarios for hydrogen pathways for Australia by 2050. The energy system model shows that Australia has a competitive position to produce green hydrogen from electrolysis to meet the emissions-free global demand for transport, utilities, electricity, heat generation, and industrial feedstock. Aligning with the Paris climate goals, ClimateWorks models emissions reduction scenarios compatible with a two-degree global temperature limit. ClimateWorks identify biogas, hydrogen, and CCS as transformational technologies. Those technologies include, in the electricity sector, demand management, the use of power produced from 100% renewable sources and reliance on new storage capabilities; in the building sector, deep energy efficiency and electrification; in transport, electric and fuel cell vehicles for road and short-haul routes; in the industry sector, energy efficiency, circular economy principles, and industrial CCS; and in the agriculture and land sector, sustainable practices and carbon forestry. The work is focused on the achievement of ecologic and social goals rather than economic viability.

COAG Energy Council, CSIRO, and the Hydrogen Council develop a hydrogen roadmap. Roadmaps help to inform timely investment decisions. The Hydrogen Council is a global initiative of energy-intensive companies from the energy, transport, and industry. Whereas Hydrogen Council's approach is based on qualitative stakeholder consultation while CSIRO and COAG Energy Council have taken a more scientific and quantifiable approach. CSIRO uses a national and international cost and technology benchmark. Deloitte consulted COAG Energy Council. Hydrogen deployment delivers deep decarbonisation of transport, industry, and buildings and enables a renewable energy production and distribution system by 2050. Hydrogen is not seen as the single solution to all problems but as an enabler along with other low carbon technologies.

Geoscience Australia has been engaged by the Department of Industry, Innovation and Science to develop maps that show prospective hydrogen production regions of Australia. The maps inform Australia's National Hydrogen strategy. CCS hydrogen is highly prospective in Victoria using brown coal or gas due to the co-location of fossil fuels, an extensive storage reservoir, access to water, and good infrastructures like ports, pipeline easements, and electricity networks. However, there is no critical consideration of the results' ecologic, social, and economic assessment.

3.4 Role of government

The Victorian Government can play a crucial role to support the transition to net zero emissions for the Victorian gas sector. The section will summarise the key risks and opportunities of proposed decarbonisation policies and government actions.

The literature review identifies recommendations for decarbonisation policies, implementation strategies for hydrogen and biogas, and a regulatory review to explore how hydrogen and biogas can be injected into existing gas networks.

Energy policy must be reformed to cut carbon emissions to near zero over the next 30 years (Grattan Institute 2019). Emissions reduction requires action by the government, businesses, and individuals Policies made by governments can drive emissions reduction through legislation, regulation, and incentives. Governments can provide essential infrastructure to support the rollout of technologies and reduce non-price barriers to their adoption (ClimateWorks Australia 2020a). Emissions projections associated with Victoria's current policy measures will not be enough to achieve net zero emissions of Victoria's existing gas infrastructure. The most important goal is to establish near-term, ambitious interim targets for developing cost-effective renewable gas (Energetics 2019). The analyses show that alternative gas with biogas, hydrogen, and CCS scenario is lower cost than the electrification scenario. Therefore, decarbonisation policy needs to support a broad range of decarbonisation options and technologies (Frontier Economics 2020b) (Deloitte Access Economics 2017).

Victoria must develop a clear policy and targets to develop the domestic green hydrogen economy (Deloitte 2019). The development of a policy framework creates a 'market pull' for hydrogen. Private and public investment along the value chain of hydrogen production, storage and transport are likely to follow (CSIRO 2018). Hydrogen policy measures include funding mechanisms, targets for hydrogen applications, new regulation subsidy mechanisms, creation of investment funds, and tax credit schemes. Policy recommendations for biogas are similar. Setting renewable gas targets and financial and regulatory support of plant operators will increase sector-coupling value and reduce total infrastructure costs (ENEA Consulting 2019). However, gas pipeline regulations to allow the injection of hydrogen and biogas into the existing network must be reviewed. Identified national gas law permits the injection of renewable gas, and some state legislation is conditional (Johnson Winter & Slattery Lawyers 2018). Safety standards for pipelines and appliances, in particular, need to be reviewed (Clayton Utz 2019). A certificate-style Renewable Gas Blending Scheme can help to incentivise the blending of renewable gases like biogas and hydrogen into Victoria's gas networks (Oakley Greenwood 2019).

It is still uncertain what pathway Victoria might choose to decarbonise the gas infrastructure by 2050. In the short to mid-term of 5-10 years, the Australian and Victorian Government is further investing and encourage private investment in natural gas infrastructure (Prime Minister of Australia, The Hon Scott Morrison MP 2020) (Geological Survey of Victoria 2020). However, Australian regulators, federal, and state governments have taken the first steps to support the development of these new technologies in the long-term of 10-30 years (DISER 2020c) (CEFC 2020).

The Australian Government has developed strategies and roadmaps to guide strategic and system-wide future investments in low emissions technologies. Whereas biogas or bioenergy, in general, has been neglected, hydrogen has received considerable funding in the recent past. The Victorian Government also has developed several strategies and programs to reduce emissions in the energy sector, mainly electricity generation. Due to national strategies and roadmaps, there are several research and development projects for biomethane, hydrogen, and CCS in Victoria. However, the pathway for the decarbonisation of the natural gas infrastructure is not yet decided. Infrastructure Victoria can make a vital contribution to closing this gap with the development of the gas infrastructure advice.

Table 22: Summary role of government found in literature

Opportunities	Risks
Driving cost reductions: support a broad range of technologies, including electrification, CCS, biogas, and hydrogen from SMR, gasification, and electrolysis Long-term commitment: coordinated investment support in research, development, demonstration, and early-stage commercialisation Create demand: develop value chains for hydrogen hubs Build capacity: support the development of standards and knowledge in the hydrogen industry	Uncertain financial viability of projects and high cost-competitiveness of alternative technologies Market constraints and missing national targets, levies The complexity of project development and operation and lack of supporting infrastructure Absent regulation, standards, and consumer acceptance

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