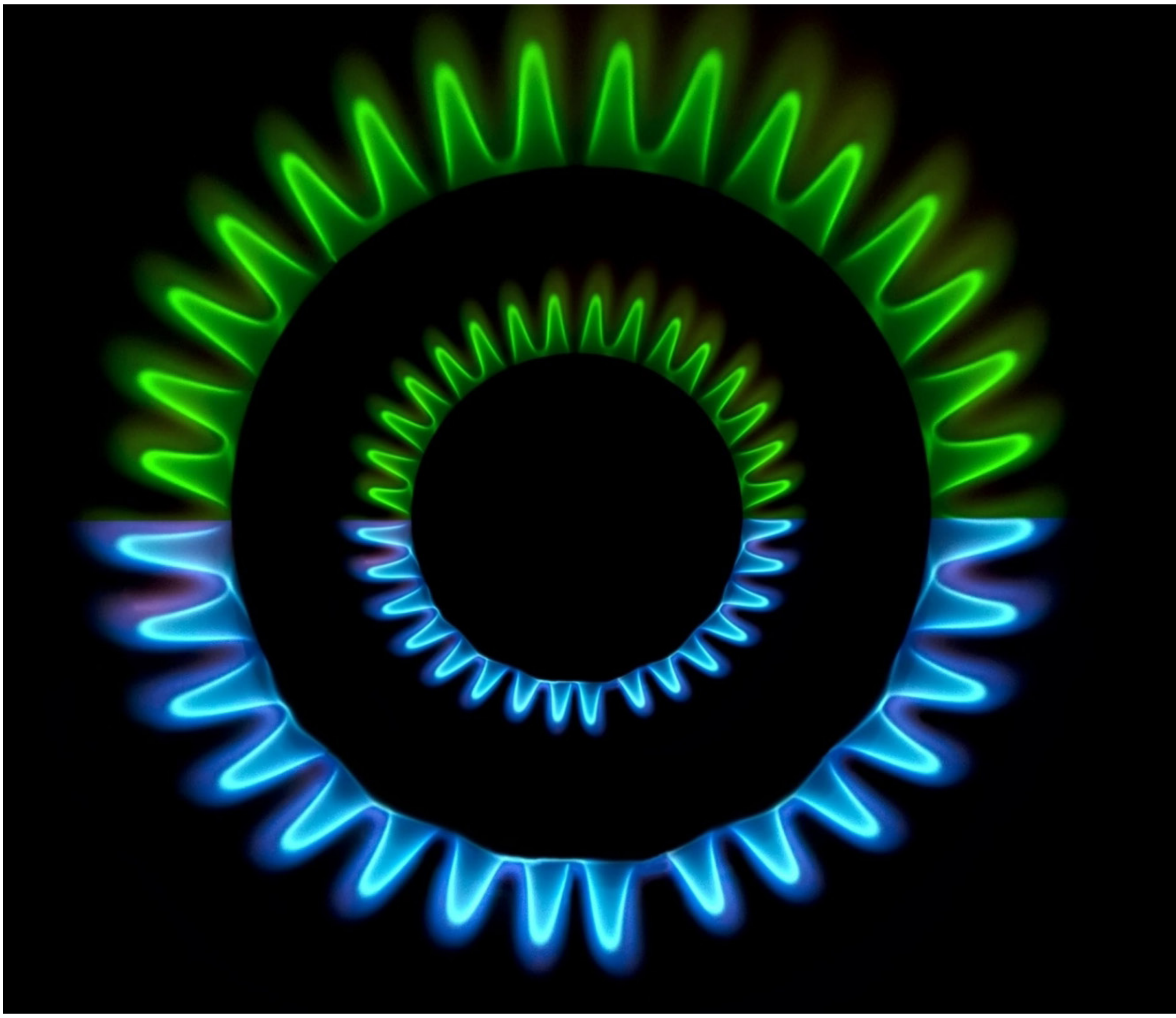
WHEN TRUST MATTERS

NATIONAL GAS DECARBONISATION PLAN

Decarbonising Australia's gas pipelines and networks



Energy Networks Australia

APGA

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1 EXECUTIVE SUMMARY

This report provides a detailed national work plan for decarbonising Australia's gas transmission pipelines and distribution networks, supporting national emissions reduction commitments and state and territory net zero targets.

Australia's gas pipelines and networks deliver affordable and reliable energy to over 5 million household and business customers, with natural gas accounting for 26% of Australia's overall energy mix. Transitioning the gas system to renewable and decarbonised gases will help to eliminate the 80 million tonnes of annual CO_2 emissions from natural gas, for both energy and feedstock, which are almost 15% of Australia's total.

1.1 The need for renewable and decarbonised gas

The need for an energy transition is so major and so urgent that all decarbonisation options need to be considered. Alongside the requirement for large-scale and rapid renewable electricity deployment, the decarbonisation of those sectors which are difficult to substantially electrify can be achieved in parallel through the large-scale and rapid deployment of renewable and decarbonised gases. Both approaches will be needed to achieve net zero in a timely and cost effective manner.

Through this detailed and practical plan, Australia's gas pipelines and networks will help deliver the transition to green gases in practice.

1.2 Objectives

This plan is designed to deliver the three objectives that are needed to meet the overall net zero aim described in Gas Vision 2050[1]:

1. Enable blending of up to 10% by volume of renewable and decarbonised gases by 2030.
2. Enable 100% renewable and decarbonised gas supply to new residential developments before 2030.
3. De-risk a full network conversion to 100% renewable and decarbonised gases by 2050.

Individual gas network and pipeline businesses may have targets that diverge from these objectives, including some which are more ambitious. A mix of renewable and decarbonised gases will be needed to deliver net zero, including, but not limited to, green hydrogen from renewable energy sources (e.g. electrolysis using renewable electricity), biomethane from sustainable sources, or renewable methane.

1.3 Tenets of a Successful Plan

To be successful, a gas network transition to initially blended and then 100% renewable and decarbonised gases needs to meet five key principles, or tenets:

- **Customer Focus:** Consumers today benefit immensely from cost-effective and convenient gas supplies, and rely on gas for a range of services, including cooking, hot water, space heating, power generation and industrial heat and feedstock. The transition must support consumers in the residential and commercial, industrial, power generation and transport sectors to decarbonise in a cost-effective and convenient way, keeping disruption to a minimum.
- **Safety:** The high safety standards that exist for the current gas grid need to be maintained, through the development of the best technology and procedures for renewable and decarbonised gases across the Australian gas system, including the high-pressure transmission pipelines, the low-pressure distribution network, and end-user appliances.
- **Security of Supply:** A renewable and decarbonised gas network needs to maintain the high security of supply standards that currently exist, with very rare unplanned interruptions, including through ensuring

[1] Energy Networks Australia, Gas Vision 2050, https://www.energynetworks.com.au/projects/gas-vision-2050/

sufficient physical network capacity, efficient and safe System Operation, and access to sufficient renewable and decarbonised gas production and storage capacity.

- **Market Development:** To achieve net zero, the gases in the network need to be certified as genuinely renewable and low carbon, enabling producers to produce renewable and decarbonised gases at a competitive price, with customer contracts forming the basis for project and long-term operational financing, together with appropriate market incentives.
- **Supply Chain:** The supply chain and skilled workforce needs to be available at the right scale and with sufficient agility to deliver the renewable and decarbonised gas transition on time, including the provision of enough appliances and other equipment, and to carry out the installations, connections, and asset upgrades safely and smoothly.

Appropriate regulation is also an important enabler, as described in Section 1.6.

The graphic below gives an overview of the plan structure.

National Gas Decarbonisation Plan

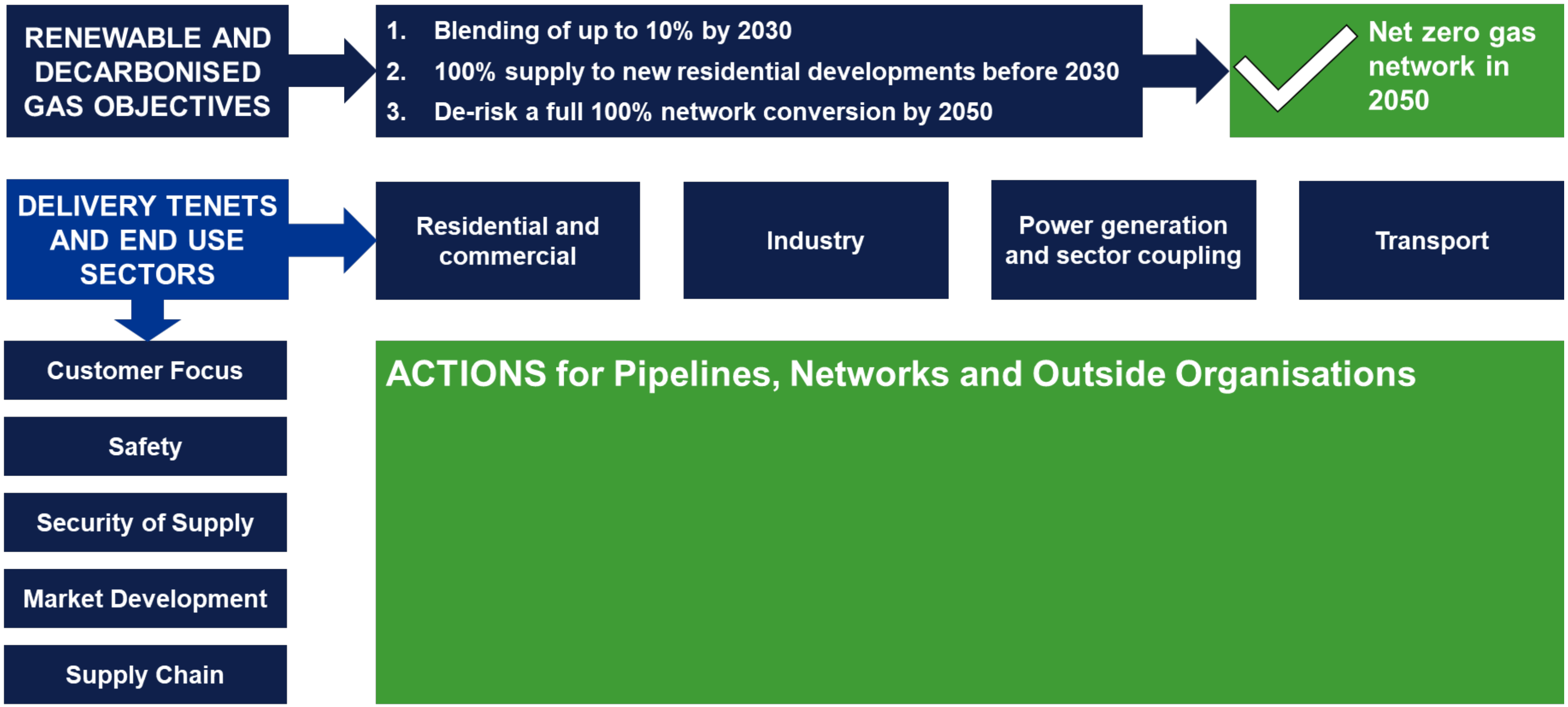

Figure 1: National Gas Decarbonisation Plan Structure

1.4 End-use Sectors

This plan allocates actions related to different end-user sectors in Australia, with a strong role for renewable and decarbonised gases in the following sectors:

- **Residential and commercial:** Currently, almost half of Australian households are connected to the natural gas network, with the proportion being above 70% in ACT and Victoria. Total residential connections rise rising to nearly 70% of households if LPG connections are included, with a combined total of over 18 million residential gas appliances:
    - Renewable and decarbonised gases can provide households, restaurants and other businesses with the same positive experience of cooking and heating with gas as today.
- **Industry (manufacturing and mining):** Industry today uses natural gas predominantly in burners, gas engines and turbines. It also uses natural gas for space heating and as a feedstock. The metals and chemicals sectors are the biggest industrial gas users in Australia, but industries such as food and drink and glass are also major users:
    - Renewable and decarbonised gases are essential for certain industrial sectors and processes, in particular:
        - For the production of high-temperature heat;
        - For the generation of a flame, where industrial processes require direct exposure to flames;
        - As a chemical feedstock.
- **Power generation and sector coupling:** Gas generates around 20% of Australia's electricity, with the proportion above 50% in some regions. Gaseous power generation – increasing from renewable and decarbonised gases – is likely to remain an important part of the Australian electricity system, supporting renewables in the progressive replacement of coal:
    - Gas can provide storage and peaking power for much longer than a battery and can provide resilience, helping the electricity system to accommodate short-term hourly, daily and weekly fluctuations in renewable generation. Green hydrogen production can also help to balance electricity supply, with electrolysers running during periods of high renewables output.
- **Transport:** Renewable and decarbonised gases are solutions for long-distance, heavy and high-utilisation transport, including heavy goods vehicles, buses, public service vehicles, forklift trucks and ships. Gaseous fuels offer long ranges and fast refuelling times.

1.5 Pipeline and network actions in the next five years

The plan describes the actions required from transmission pipelines and distribution networks in detail. These are mainly focused on meeting the customer focus, safety, security of supply and supply chain tenets. The main body of the report details the actions needed in the next five years, the second half of the 2020s, and the 2030s and 2040s. In the below executive summary, we focus on the actions required in the next five years:

Renewable and decarbonised methane

Renewable and decarbonised methane is very similar to natural gas and can meet gas quality standards. Blending of renewable and decarbonised methane with natural gas at any level does not pose technical issues to the network assets or the consumer. To deliver renewable and decarbonised methane, key actions include:

- **Customer focus:** Ensure customers have sufficient access to renewable gas through transparent green gas certification and that any metering and billing issues relating to blends of renewable gases are addressed.
- **Safety:** Existing methane gas quality specification needs to be updated to consider additional constituent components found in some forms of renewable and decarbonised methane.
- **Security of supply:** A strategy for renewable and decarbonised methane supply and storage, together with natural gas back up during the transition, will be needed, including more renewable and decarbonised methane producers to connect to networks.
- **Supply chain:** Training facilities and material will be needed to be developed for the workforce. The equipment supply chain will need to be educated and a renewable and decarbonised methane business case developed.

Renewable and decarbonised hydrogen

The next five years are critical to the renewable and decarbonised hydrogen transition – this is when the 10% blending trials and the preparatory work for 100% trials in new property developments and conversion of existing networks to 100% hydrogen needs to take place. Key actions include:

- **Customer focus:** Ensure customers have sufficient access to renewable gas through transparent green gas certification and that any metering and billing issues relating to blends of renewable gases are addressed. Public engagement on hydrogen conversion will be needed, much of which is underway, including taking on board feedback from the interim blending and trials steps. Practical trials will be needed to demonstrate to consumers that hydrogen works well, and pipelines will need to engage with directly connected customers.
- **Safety:** 10% blended and 100% hydrogen gas quality specifications will be needed, together with work to assess existing Type A and B appliances. Safety risk assessments for blending and 100% hydrogen need to be completed and workforce training started. Specific consideration of repurposing existing gas transmission pipelines is also needed.
- **Security of supply:** A strategy for hydrogen supply and storage, including maintaining the natural gas parts of the network during the transition, will be needed. Network modelling and network entry improvements will need to be carried out to facilitate more hydrogen producers to connect, and System Operation will need to be reviewed for both 10% and 100%.
- **Supply chain:** Training facilities and material will be needed for the workforce, and engagement needs to take place with manufacturers of hydrogen equipment, including for networks and end-user hydrogen-ready appliances. A business case also needs to be developed.

Cross cutting actions

The plan does not determine the balance of renewable and decarbonised hydrogen and methane to be taken in each network, but sets out the pathway to each objective. Three cross-cutting actions are critical, whatever the precise green gas mix:

- **Engagement:** Comprehensive public, property developer and industry engagement to build support for the renewable and decarbonised gas transition and ensure that consumers and the supply chain are ready.
- **Joint renewable and decarbonised hydrogen and methane planning:** With varying renewable electricity, biomethane feedstock, CCS availability and other factors in different regions, the mix of renewable and decarbonised hydrogen and methane in the transition will vary across networks. Joint

planning, including with renewable and decarbonised gas producers and electricity networks, will help to ensure the most cost-effective and sustainable transition in each region.

- **Business case:** Ultimately, markets need to be developed for renewable and decarbonised gases, as they have been for renewable electricity generation. A joint business case should therefore be developed for both renewable and decarbonised methane and hydrogen, complementing the joint planning described above, to demonstrate to outside organisations how renewable and decarbonised methane and hydrogen can be developed and substantial emissions reductions achieved cost-effectively.

1.6 Actions from Outside Organisations

The plan also sets out the main activities required from governments, regulators, appliance manufacturers and renewable and decarbonised gas producers. These are required to meet the market development tenet, support the security of supply and supply chain tenets, and provide the right regulatory framework for decarbonisation. Most of these actions are needed in the next five years.

Regulatory changes

Removing regulatory roadblocks formed through historic regulation which didn't consider renewable and decarbonised gases, and setting in place regulatory frameworks within which a renewable and decarbonised gas economy can develop, will be key to forming a foundation from which renewable and decarbonised hydrogen and methane industries can grow. Harmonisation of technical, environmental and economic regulation across the whole of Australia would streamline and simplify the decarbonisation plan. Key actions include:

- **Technical regulation:** Update gas quality regulations for renewable and decarbonised methane and hydrogen and agree billing methodology for blends. A specification for 100% hydrogen will be needed, and policy decisions will need to be made on new and converted 100% hydrogen networks, including mandating hydrogen-ready appliances.
- **Environmental regulation:** Develop environmental management and land use regulations for renewable and decarbonised methane and hydrogen, including water supplies and bio feedstocks. National Greenhouse Energy Reporting Scheme (NGER)[2] and other relevant schemes should also recognise renewable and decarbonised gases in energy and emissions reporting frameworks.
- **Economic regulation:** Updates to the National Gas Law to allow it to cover renewable gases, and reporting regulations, are needed, and reservation policies would ensure that domestic use is prioritised when supply is tight.

Market development

A renewable and decarbonised gas market will be key to enabling the development of green gas uptake through gas networks and pipelines, and key actions include:

- **Certification:** Green gas certification schemes are required to provide customers with confidence that they are purchasing a green product.
- **Renewable gas target:** A starting point would be to implement a target for renewable and decarbonised gas, similar to the existing renewable energy target. This would help to underpin investment in renewable and decarbonised methane and hydrogen, and support the market creation activities below.

[2] National Greenhouse Energy Reporting (NGER) Scheme established by the National Greenhouse and Energy Reporting Act 2007

- **Market access:** Market access is needed to enable renewable and decarbonised gas demand to access supply through pipelines and networks, and includes the development of green gas standards and tradeable certificates.
- **Early asset financing:** Early market supply can be seeded through existing government financing frameworks, including the Emissions Reduction Fund, Australian Renewable Energy Agency (ARENA) project funding and Clean Energy Finance Corporation (CEFC) equity and debt. Access to lower risk financing will be key to enabling first supply into potential renewable and decarbonised gas markets, after which market forces can take over.
- **Market incentives:** Putting in place financial incentives which enable customers to purchase renewable gas will support market development in line with emissions reduction targets. This includes tax or retail price incentives.

Production and end-user technical development

Alongside gas pipeline and network actions, technical development of decarbonised gas infrastructure requires further technical development of end use and production of renewable and decarbonised hydrogen and methane.

- **Appliances:** Appliance manufacturers need to develop hydrogen and hydrogen-ready Type A and Type B appliances at scale, suitable for the Australian context. This includes safety and performance testing, certification, consumer engagement to demonstrate efficacy, manufacture/import at scale and workforce training.
- **Production:** End-usage in Australia, and the ability of networks to transport the gases from production to consumption, needs to be fully taken into account. This includes making sure that projects designed for hydrogen export, and/or for local industrial use, are sized appropriately to supply a wider set of Australian customers, and that sufficient daily and seasonal storage is available.

1.7 The top five no-regrets actions

In order to achieve the objectives on time, there are several key actions that need to be kick-started as soon as possible.

Certification	National Gas Law	Appliance development	Business case for blending	Biomethane resource
Ensure that renewable and decarbonised gases are certified so that consumers are able to purchase green gases with confidence.	Update the National Gas Law to allow renewable and decarbonised gas blends to be recognised.	Develop hydrogen and hydrogen-ready appliances suitable for use in Australia – the sooner these can be rolled-out at scale, the smoother a hydrogen transition can be.	A joint business case for blending renewable and decarbonised methane and hydrogen is needed to demonstrate that they can achieve substantial emissions reductions cost-effectively and quickly.	Biomethane is a key option for reducing gas system emissions, with no changes required for consumers. Identifying the resource potential in different parts of Australia is necessary to understand the extent of the contribution biomethane can make.

Figure 2: Top five no-regrets actions

2 INTRODUCTION

In line with Australia's Gas Vision 2050, the gas transmission pipelines and distribution networks are committed to achieving low carbon gas blending across Australia at an initial level of 10% renewable and decarbonised gas by 2030, and then to proceed to 100% renewable and decarbonised gas in networks before 2050.

This document sets out a national work plan outlining how the gas transmission pipelines and distribution networks can support the achievement of these targets.

2.1 The Importance of Australia's Gas Infrastructure

Natural gas has the broadest application of all primary fuels in Australia, being used directly in households, businesses and industry as well as to generate electricity and as a fuel in transport. Utilising Australia's gas infrastructure to deliver renewable and decarbonised gas can help solve the energy trilemma by balancing energy affordability, energy security and environmental outcomes of net zero emissions.

This plan covers both transmission pipelines and distribution networks. Many of the aspects to be addressed are common to both transmission and distribution; however, the transmission pipeline specific issues are separated out where relevant.

2.1.1 Gas Supply in Australia

Gas is provided across Australia via gas transmission pipelines and distribution networks connecting the gas reserves to residential, commercial and industrial gas customers, including export facilities.

Due to the locations of gas reserves, pipelines and demands, Australia comprises three distinct gas supply regions:

- Eastern Region: Queensland, New South Wales (NSW), the Australian Capital Territory (ACT), Victoria, Tasmania and South Australia
- Western Region: Western Australia
- Northern Region: Northern Territory.

The Northern region and the Eastern region are connected by the Northern Gas Pipeline but the Western Region remains isolated from the other regions.

Gas regions and pipeline locations are shown in **Figure 3** below

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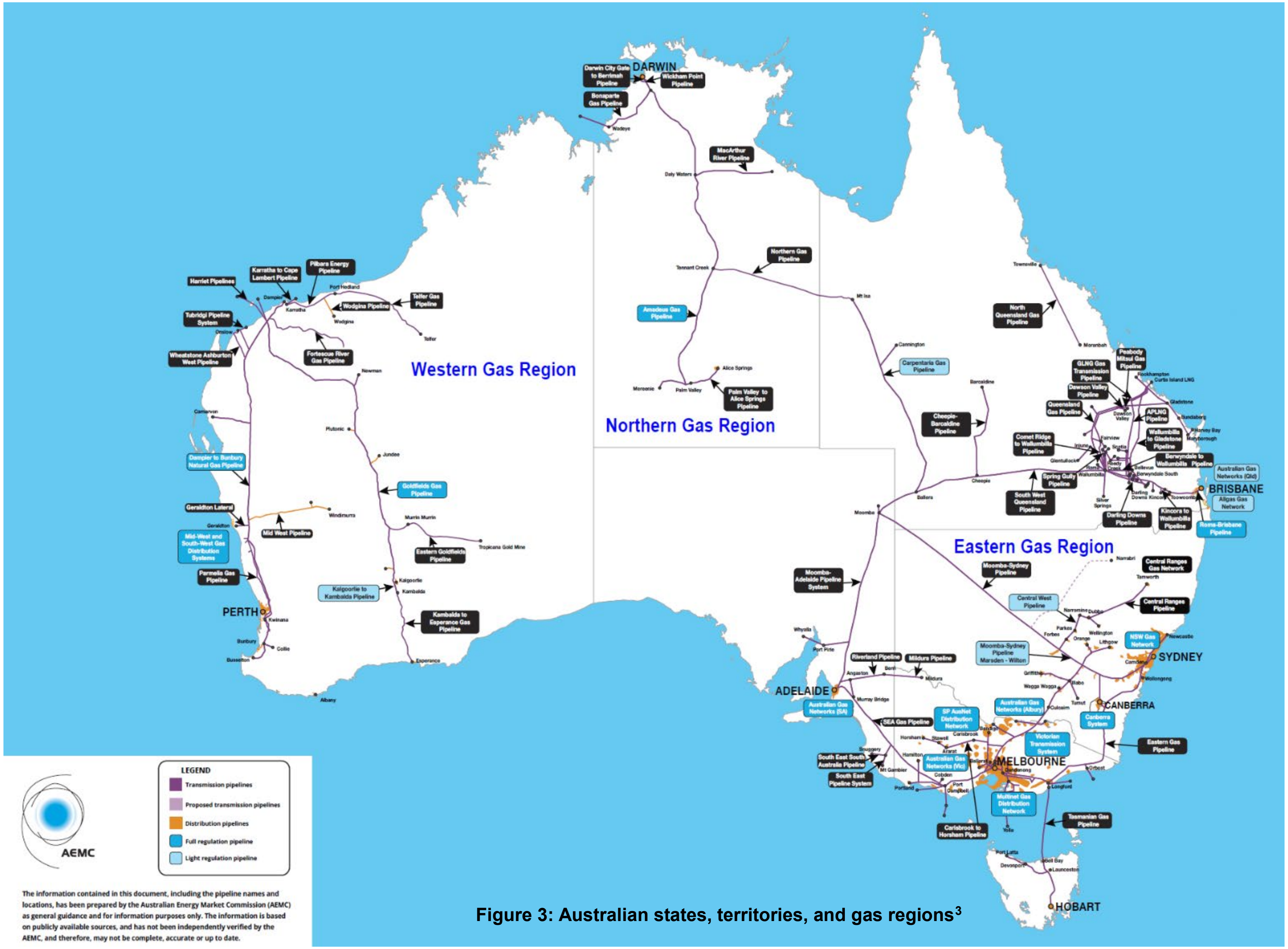


Figure 3: Australian states, territories, and gas regions[3]

[3] AEMC, Pipeline Map of Australia, https://www.aemc.gov.au/energy-system/gas/gas-pipeline-register

Gas is transported at high pressure from natural gas reserves (i.e. underground gas reservoirs) via large diameter transmission pipelines to the city gate, which provides the connection between the high-pressure transmission pipelines and the lower pressure distribution networks. Metering (for billing and gas balancing), pressure reduction and odorisation is performed at the city gate. Distribution pipelines transport natural gas at a lower pressure from the city gate to end users (residential, commercial and industrial). In addition, some major power stations and industrial users are directly connected to the transmission pipelines.

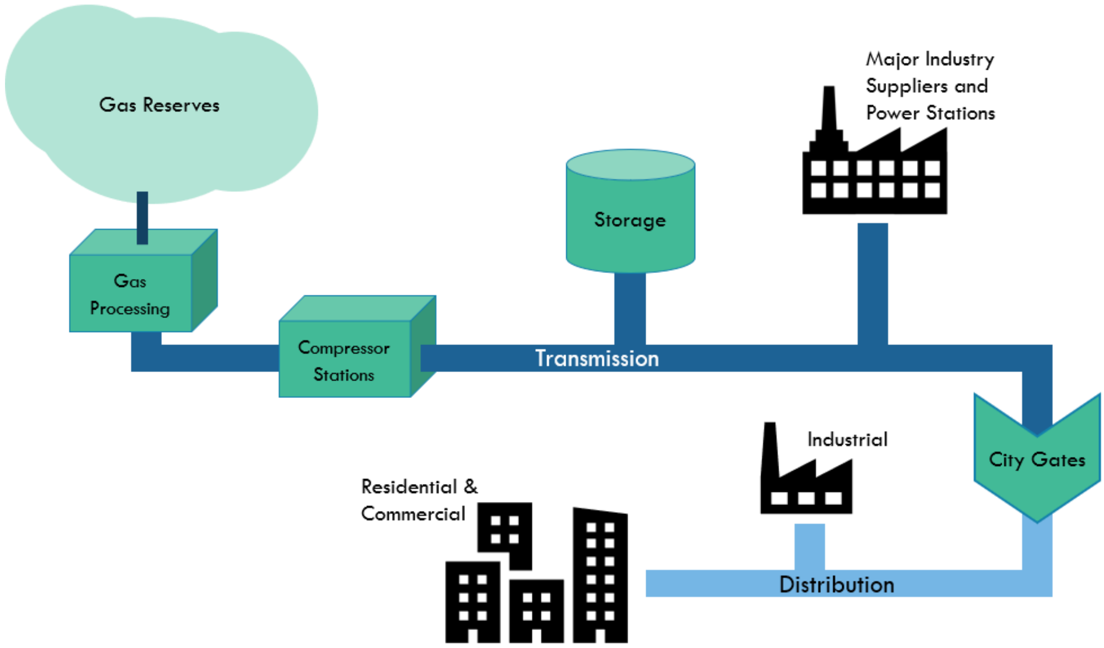


Figure 4: Current Australian Gas Supply Chain

2.1.2 The role of gas networks in Australia

Gas demand and usage varies across Australia depending on the region, with gas providing energy to households and businesses, energy and feedstock to industrial processes and fuel for electricity generation and export. **Figure 5** shows the energy consumption by fuel type in Australia in 2018-19, with natural gas usage accounting for 25.7% of energy consumption with 37% of this amount being used for electricity generation[4].

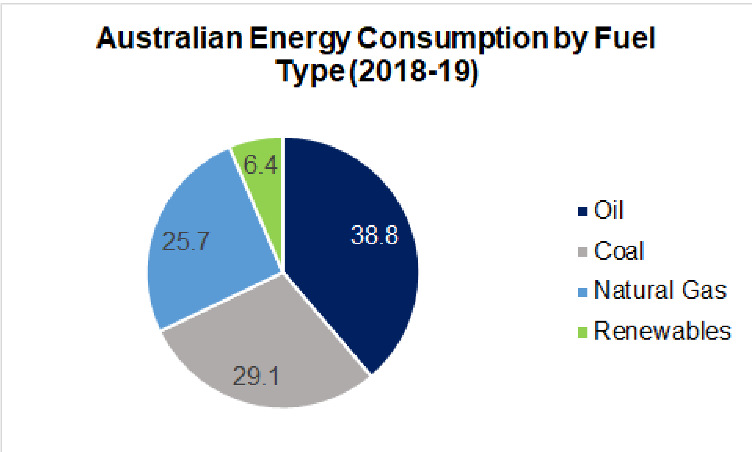


Figure 5: Australian Energy Consumption by Fuel Type fiscal year 2018-2019[5]

[4] Department of Industry, Science, Energy and Resources (2020), Australian Energy Update 2020, Australian Energy Statistics, September 2020
[5] Department of Industry, Science, Energy and Resources (2020), Australian Energy Update 2020, Australian Energy Statistics, September 2020

Over recent decades, natural gas uptake in Australia has grown at 3.2% per year, roughly double the pace of overall energy consumption in Australia. As shown in Figure 6 domestic natural gas demand grew substantially over the past three decades, outpacing overall energy demand over the same period.

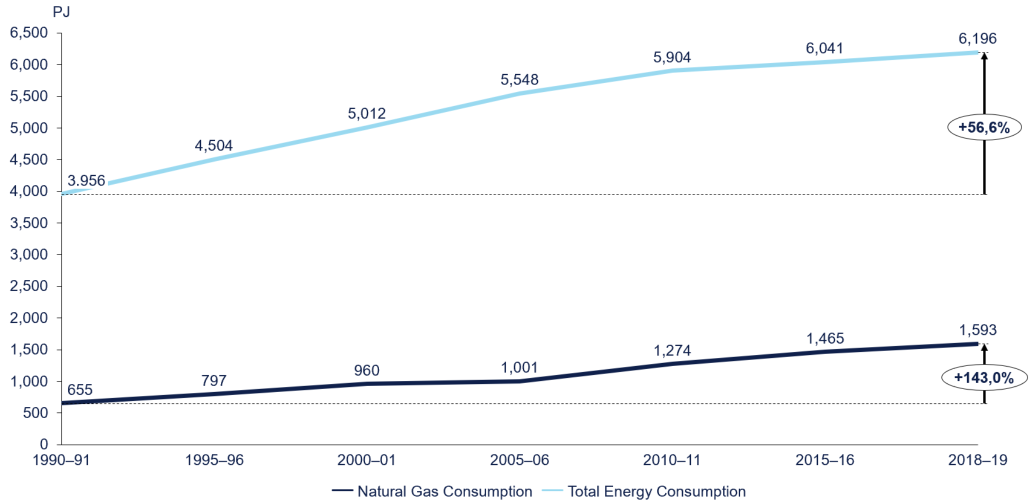


Figure 6 Australian natural gas and overall energy consumption 1990 – 2018[6]

A key factor in driving this growth was demand in the power sector, which roughly doubled its share in the overall Australian domestic demand for natural gas, see Figure 7. Overall, natural gas is predominantly used in industry (47% in 2018), power generation (37% in 2018) and for residential/commercial use (14%).

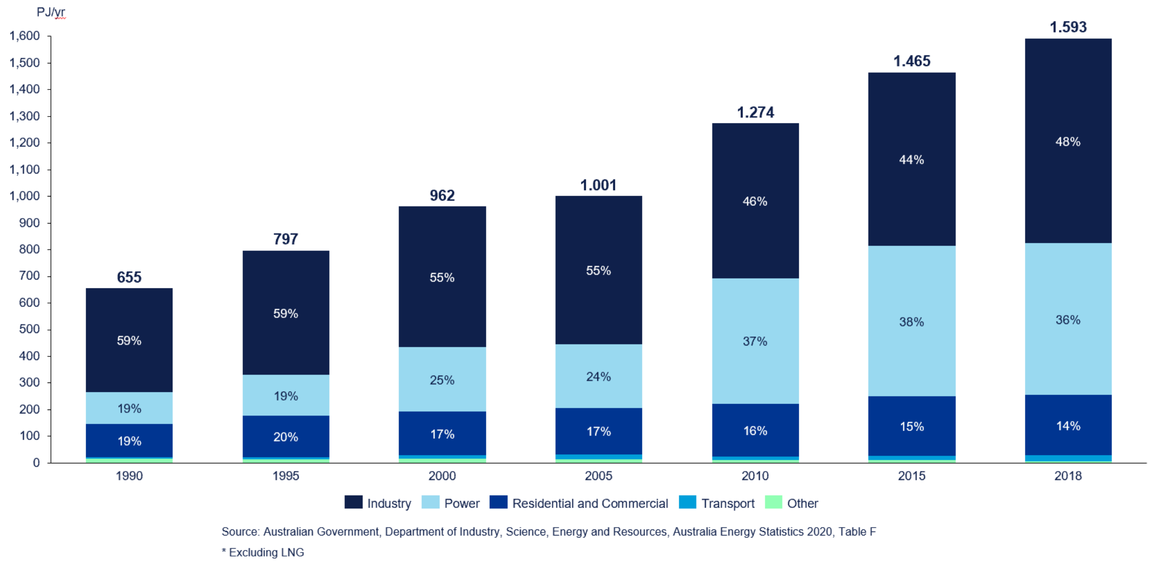


Figure 7 Australian domestic gas consumption 1990 – 2018[7]

As shown in Figure 8, Australian gas consumption on a state level is dominated by Western Australia (WA), Victoria (VIC) and Queensland (QLD), however, each state has a particular role for natural gas in its energy system. Victoria has a far larger share of residential demand in its gas consumption, and Western Australia and Queensland a far higher demand for power and industrial use.

[6] Department of Industry, Science, Energy and Resources (2020), Australian Energy Update 2020, Australian Energy Statistics, September 2020

[7] Department of Industry, Science, Energy and Resources (2020), Australian Energy Update 2020, Australian Energy Statistics, September 2020

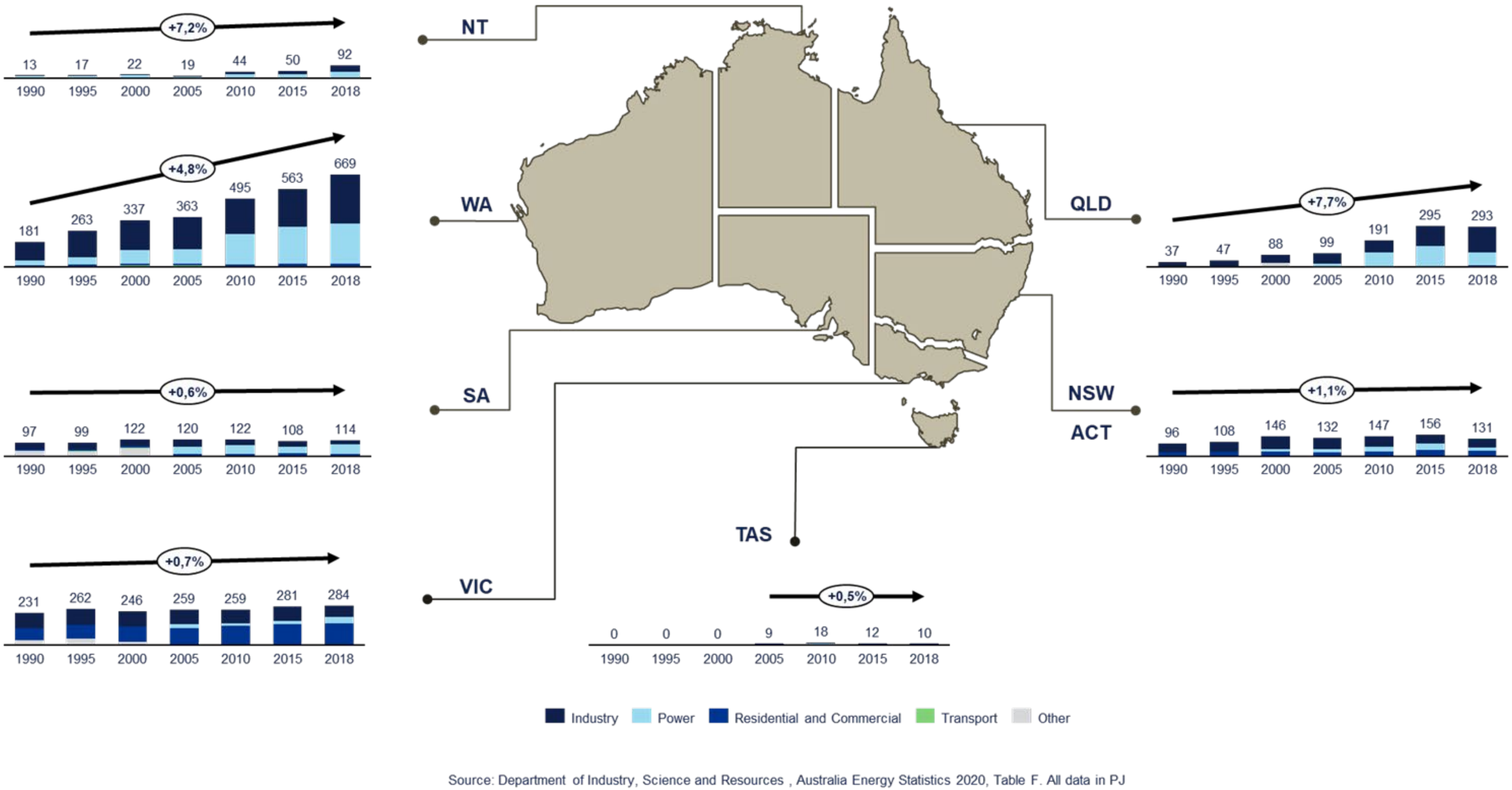


Figure 8 Australian gas demand development per sector and State/Territory,1990-2018[8]

[8] Department of Industry, Science, Energy and Resources (2020), Australian Energy Update 2020, Australian Energy Statistics, September 2020

Australia's overall carbon emissions have decreased by 0.5% per year over the period 1990-2018 (from 618 $MtCO_2$-e to 538 $MtCO_2$-e). The primary source of carbon reductions over the period 1990-2018 has been the decline of emissions related to Land Use, Land-Use Change and Forestry (LULUCF). However, emissions from energy uses have increased over the period by 1.4% per year over the period reaching 436 Mt CO_2-e in 2018, an increase of 48% as of 1990.

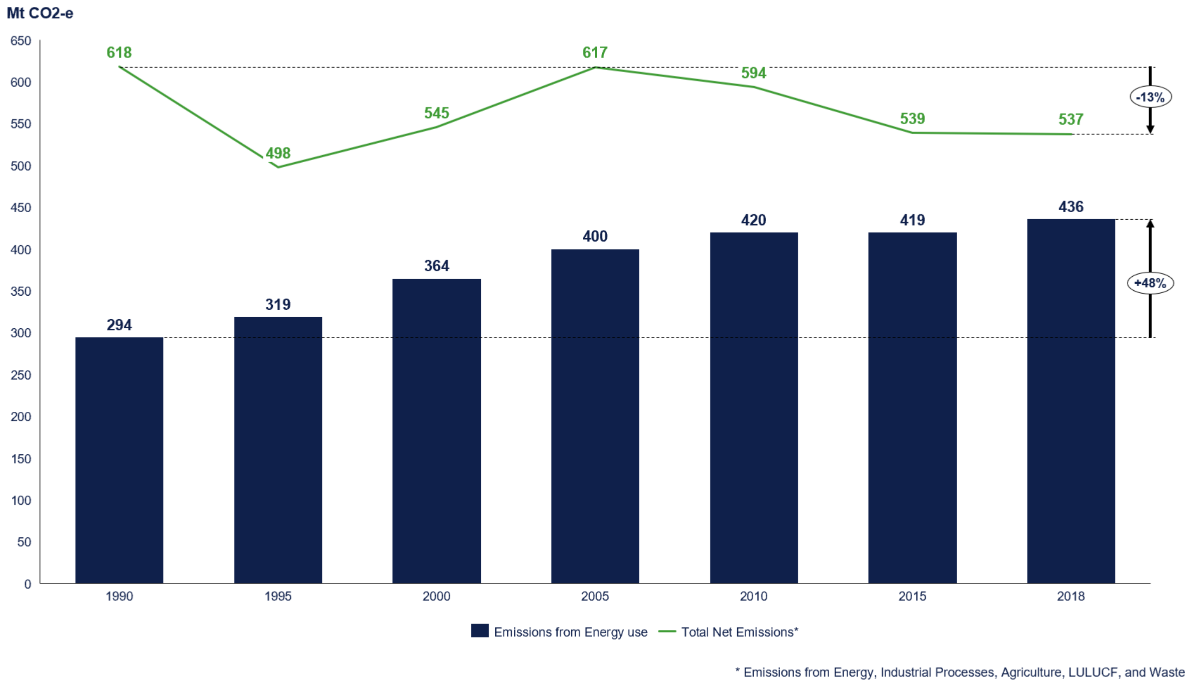


Figure 9 Australian Greenhouse Gas emissions 1990 – 2018[9]

Although the Australian government has committed itself to a 26-28% reduction in carbon emissions from 2005 levels by 2030 (overall reductions from 2005 (and 1990 as well) stood at 13% in 2018/19), it is clear that further work remains to be done if a reduction in line with the 2015 Paris agreement is to be reached. With GHG-emissions related to energy use accounting for 81% of economy wide emissions in 2018, the onus will continue to be on the energy sector to deliver deep decarbonisation.

2.1.3 The importance of storage

Australia has considerable levels of gas storage, both in the transmission and distribution pipelines themselves (linepack), and in underground facilities. Combined, gas storage in Australia is equal to 6 billion Tesla Powerwall batteries.[10]

This provides the gas system with considerable flexibility to manage fluctuations in demand. Put simply, linepack storage enables day-to-day fluctuations in demand to be managed, and underground storage helps to meet seasonal peaks in demand. The cost of gas storage is also considerably cheaper than electricity storage in the form of batteries.

[9] Department of Industry, Science, Energy and Resources (2020), Australia's National Greenhouse Accounts, State and Territory Greenhouse Gas Inventories 2018.

[10] Energy Networks Australia, Guide to Australia's Energy Networks https://www.energynetworks.com.au/resources/fact-sheets/guide-to-australias-energy-networks/

2.2 Australia's Decarbonisation Commitments

The decarbonisation of the gas sector will help Australia to meet the nation's emissions reduction commitments under the Paris Agreement on climate change of 2015. The Australian states and territories have each separately set an ambition of reaching net-zero emissions by 2050 or earlier.

Most of the states and territories have also set interim targets. However, many of these are focussed on the electricity sector only, and there are currently no policy measures in place to implement these renewable electricity generation targets across all other sectors. As an indication of the overall challenges an overview is provided in Figure 10 of the (linear) pathways towards net zero emissions for the individual states and territories.[11]

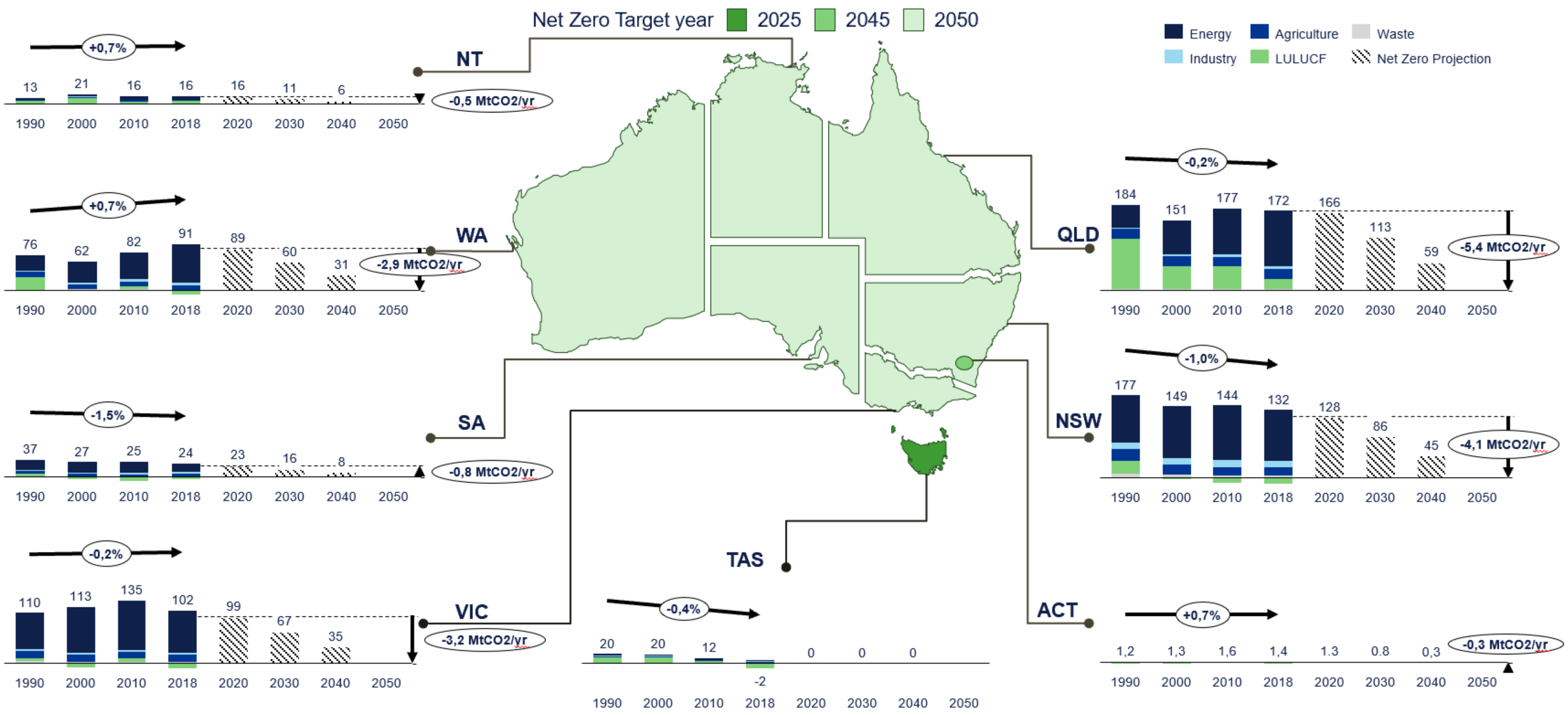
With the exception of Tasmania (endowed with extensive renewable resources), this would mean a rapid acceleration of current decarbonisation pace and in some instances, a stark reversal of long-term upward emissions trends. Overall, states and territories would have to reduce their GHG-emissions by more than 10% per year if a linear pathway is to be followed. However, the starting point for various states differ greatly and therefore the absolute effort per state will also differ greatly going forward ranging from annual reductions of 5.4 $MtCO_2$-e in Queensland to 0.3 $MtCO_2$-e in ACT.

With hydrogen as a renewable and decarbonised gas option to support decarbonisation, the Council of Australian Governments (COAG) Energy Council delivered Australia's National Hydrogen Strategy[12] in November 2019. This Strategy sets out a high-level framework through 57 strategic actions to support the development of domestic and export hydrogen industries. Four of those actions were directly relevant to low carbon gas blending in gas networks. Almost all states and territories have also committed to a hydrogen strategy for their region, and the national strategy complements the state-based ones. Both NSW and WA have aspirational targets to achieve 10% hydrogen blending by 2030.

For biomethane, a bioenergy roadmap is under development by the Australian government, which will outline the opportunities of bioenergy to support decarbonisation.

[11] Linear future emission reduction is an assumption from DNV for illustrative purposes only.

[12] Commonwealth of Australia, Australia's National Hydrogen Strategy, COAG Energy Council, November 2019 https://www.industry.gov.au/data-and-publications/australias-national-hydrogen-strategy



Source: Department of Industry, Science and Resources. Data in Mt CO2-e. Forecasts are linear projections from 2018 level to net zero in 2050, with ACT target net zero in 2045, and TAS overall Net Zero in 2020, and historical CARG excl. LULUCF.

Figure 10 Australia's state and territory ambitions regarding net zero decarbonisation[13]

[13] Department of Industry, Science, Energy and Resources (2020), Australia's National Greenhouse Accounts, State and Territory Greenhouse Gas Inventories 2018.

2.3 Gas Vision 2050

Energy Networks Australia (ENA) gas network and Australian Pipelines and Gas Association (APGA) members have been working towards decarbonising their gas transmission pipelines and distribution networks with renewable and decarbonised hydrogen and methane innovation through demonstration projects, research and testing programs in line with the Gas Vision 2050[14].

The drive for a hydrogen supply chain in Australia has been continuously accelerating since the Gas Vision was published in 2017. This includes:

- The development of the federal and state hydrogen strategies.
- Investment by the gas industry in demonstrating renewable hydrogen production facilities including the gas networks' renewable hydrogen, biomethane and synthetic renewable methane demonstration projects.
- The establishment of the Australian Hydrogen Council.
- Supporting research through the Future Fuels CRC, Australian Hydrogen Centre and other research organisations.
- Government funding at both a federal and state level to support hydrogen project and industry development.

As the gas networks continue to work towards the net zero objectives, this national plan provides the outline of activities to be undertaken to demonstrate how the gas networks can achieve the objectives.

[14] Energy Networks Australia, Gas Vision 2050, https://www.energynetworks.com.au/projects/gas-vision-2050/

3 AUSTRALIA'S NATIONAL GAS DECARBONISATION PLAN

This plan sets out how Australia's gas transmission pipelines and distribution networks will deliver the objectives outlined in the Gas Vision 2050 document to transition to renewable and decarbonised gases. It describes the projects and activities that the gas networks will carry out, together with the actions required by other organisations. Natural gas usage (covering both as energy and as a feedstock) currently accounts for just over 80 million tonnes of CO_2 emissions each year, almost 15% of Australia's total,[15] and so a full decarbonisation of Australia's gas transmission and distribution networks would make a major contribution to achieving net zero across the energy system. This plan shows how the gas networks can help Australia to achieve net zero, and support the growth of renewable energy.

3.1 Objectives

Australia's gas pipelines and networks deliver affordable and reliable energy to over 5 million households, business and industrial customers,[16] with natural gas accounting for 26% of Australia's overall energy mix and 20% of electricity generation.[17] The overall objective the industry sets out to achieve is to deliver net zero emissions from energy use by 2050 through three steps, which this plan is designed to deliver:

1. Enable blending of up to 10% by volume of renewable and decarbonised gases by 2030.
2. Enable 100% renewable and decarbonised gas supply to new residential developments before 2030.
3. De-risk a full network conversion to 100% renewable and decarbonised gases by 2050.

Individual gas network and pipeline businesses may have targets that diverge from these objectives, including some which are more ambitious.

3.2 Renewable and Decarbonised Gases

The plan considers the use and blending of different types of renewable and decarbonised gases, in the expectation that many will have some role to play in the net zero transition, which is likely to vary in different regions, depending on primary energy resource availability and other energy market developments. The gas network operators are preparing to be able to facilitate the use of renewable and decarbonised gases, including the following types:

Renewable and decarbonised hydrogen

- Green hydrogen, where the hydrogen is produced using renewable energy (e.g. from electrolysis using renewable electricity).
- Blue hydrogen, where the hydrogen is produced through the reforming of natural gas (or brown hydrogen from coal) with carbon capture and storage (CCS).
- Other types of low carbon hydrogen, for example hydrogen produced from bio resources (with CCS for negative emissions), waste plastics or pyrolysis.

Renewable and decarbonised methane

- Biomethane from sustainable sources, including from upgraded biogas.
- Synthetic methane produced, for example, from direct air captured CO_2 and hydrogen

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[15] Our World in Data, CO_2 emissions by fuel type, Australia, 2019 data https://ourworldindata.org/emissions-by-fuel

[16] Energy Networks Australia, Guide to Australia's Energy Networks https://www.energynetworks.com.au/resources/fact-sheets/guide-to-australias-energy-networks/

[17] Australian Government, Department of Industry, Science, Energy and Resources, Australia Energy Statistics 2020 https://www.energy.gov.au/news-media/news/australia-energy-statistics-2020-update-published

It is worth noting that the characteristics of hydrogen in gas networks are similar across the various sources of renewable and decarbonised hydrogen. The hydrogen part of the plan can therefore encompass the various types of renewable and decarbonised hydrogen production. For renewable methane, the characteristics of biomethane and synthetic methane are also very similar and therefore both types can be considered together in this part of the plan. Note that the plan does not determine the balance of renewable and decarbonised hydrogen and methane to be taken in each network but sets out the pathway to each objective.

The production at scale of these renewable and decarbonised gases is generally outside the scope of regulated networks – the role of the networks is to enable their safe and efficient transmission, distribution and use. As set out in more detail below, however, these gases must be certified as genuinely renewable and/or low carbon, to be consistent with a net zero transition.

Figure 11 illustrates the renewable and decarbonised hydrogen pathways and Figure 12 illustrates the renewable and decarbonised methane pathways from production to end use.

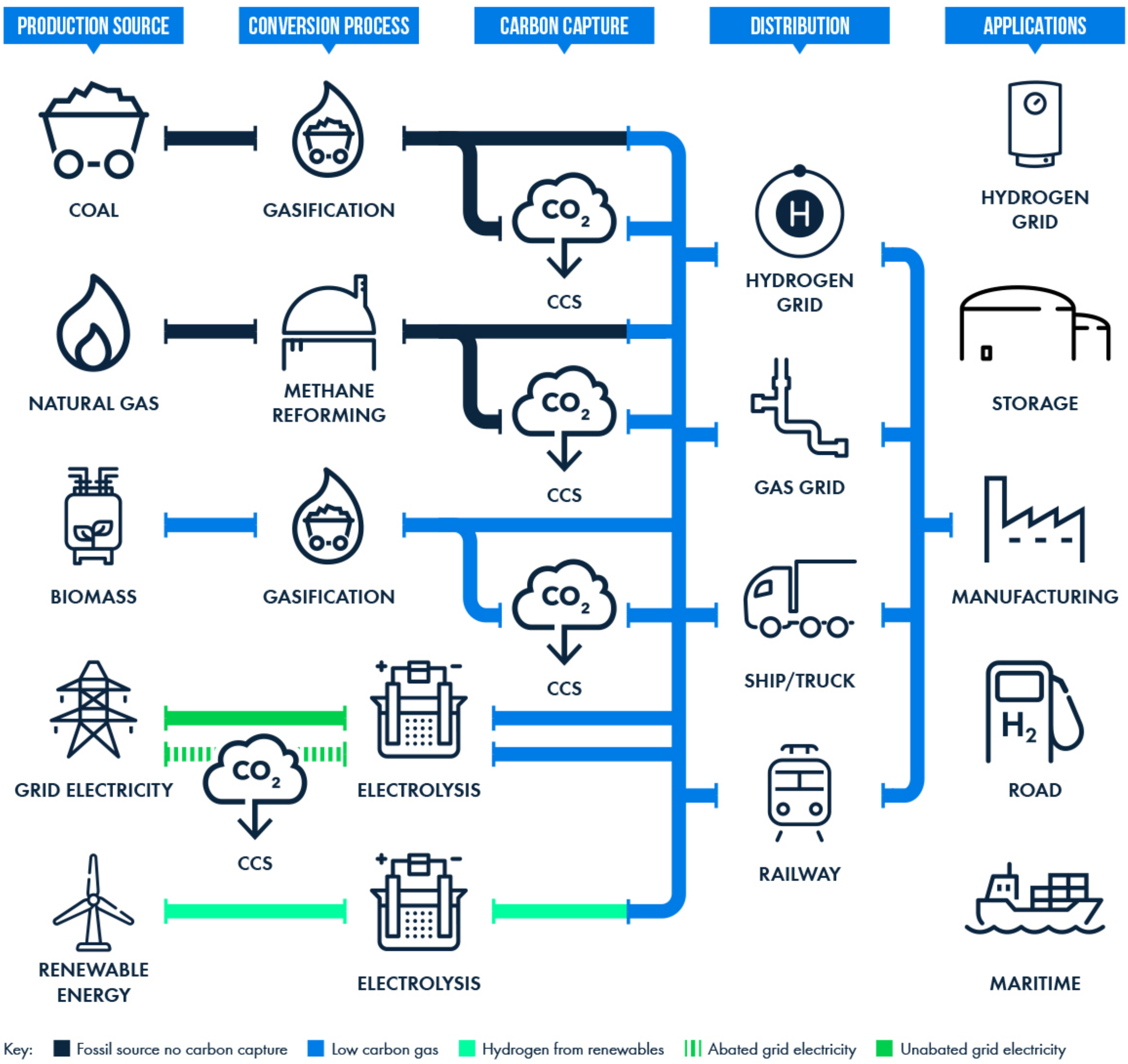


Figure 11 Renewable and decarbonised hydrogen pathways[18]

[18] Energy Networks Association, DNV, Gas Goes Green: Britain's Hydrogen Network Plan, December 2020

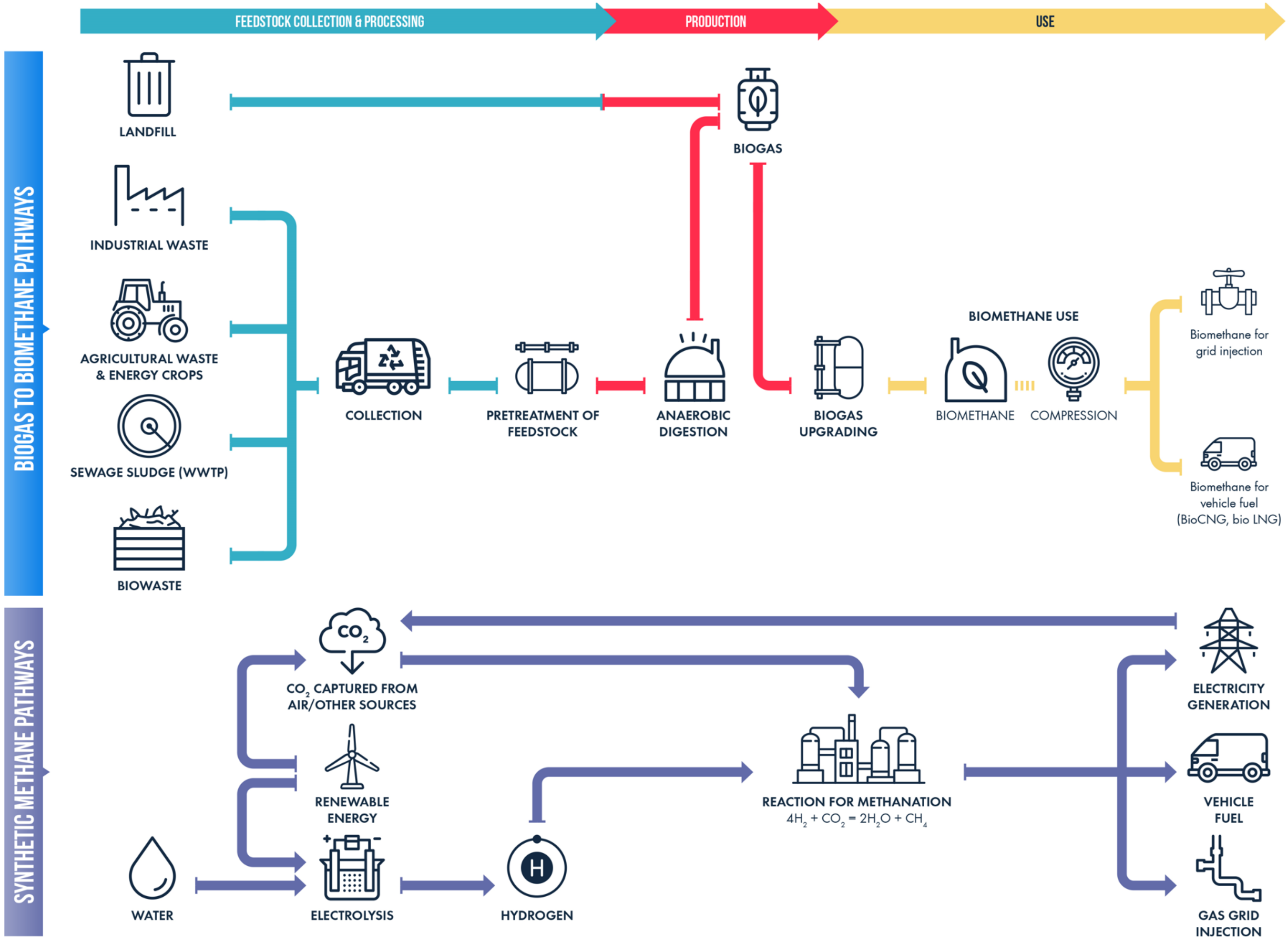


Figure 12 Renewable and decarbonised methane pathways

3.3 Tenets of a Successful Plan

To be successful, a gas network transition to initially blended and then 100% renewable and decarbonised gases needs to meet five key principles, or tenets, which are explained below.

- Customer Focus
- Safety
- Security of Supply
- Market Development
- Supply Chain

Appropriate regulation is an important enabler, and we map out the technical, economic and environmental regulatory measures in section 6.

Customer Focus

The transition must support consumers in the residential and commercial, industrial, power generation and transport sectors to decarbonise in a cost-effective and convenient way, keeping disruption to a minimum, continuing to ensure accurate billing and enabling early decarbonisation so that consumers today benefit. The transition needs to maintain the positive end-user experience as far as possible.

Safety

The high safety standards that exist for the current gas grid need to be maintained, through the development of the best technology and procedures for renewable and decarbonised gases across the Australian gas system, including:

- End-user appliances, such as domestic cookers and industrial burners.
- Design, operation, and maintenance of the low-pressure distribution network.
- Design, operation, and maintenance of the high-pressure transmission pipelines.

Security of Supply

A renewable and decarbonised gas network needs to maintain the high security of supply standards that currently exist, with very rare unplanned interruptions. This includes ensuring:

- Sufficient physical network capacity and resilience to meet demand peaks.
- Efficient and safe System Operation.
- Access to sufficient renewable and decarbonised gas production and storage capacity – this includes both seasonal storage facilities and making best use of linepack storage in the transmission and distribution networks.
- Flexibility to connect new sources at more entry points.
- Ability to connect new users.

Market Development

To achieve net zero, the renewable and decarbonised gases in the network need to be certified as genuinely renewable and low carbon, with customer contracts forming the basis for project and long-term operational financing. This may include providing end users with the right incentives to decarbonise and thereby achieve jurisdictional emissions reduction goals.

Supply Chain

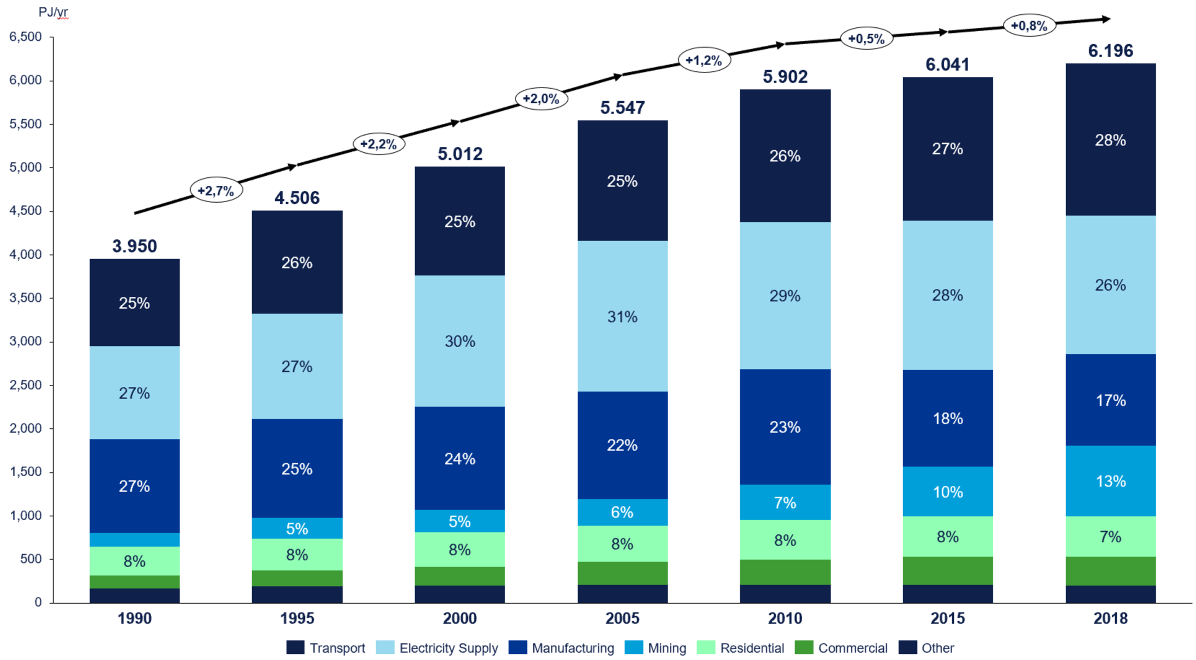
The supply chain and skilled workforce need to be available at the right scale and with sufficient agility to deliver the renewable and decarbonised gas transition on time, including the provision of enough appliances and other equipment, and to carry out the installations, connections, and asset upgrades safely and smoothly. This extends far beyond the control of the gas networks, but the transition plan needs to provide clear signals to the supply chain of expectations for support in this respect.

3.4 End-use sectors

This plan is designed to benefit the end-use sectors in Australia, which we have categorised as:

- Residential and commercial.
- Industry (manufacturing and mining).
- Power generation and sector coupling.
- Transport.

We briefly describe below the role that renewable and decarbonised gases can play in each sector. The overview of the energy demand in Australia for each of the end use sectors is shown in Figure 13 below.



Source: Australian Government, Department of Industry, Science, Energy and Resources, Australia Energy Statistics 2020

Figure 13 Sectoral Energy Demand in Australia 1990 - 2018[19]

[19] Australian Government, Department of Industry, Science, Energy and Resources, Australia Energy Statistics 2020

3.4.1 Residential and commercial

The role of gas today

Currently, almost 49% of Australian households are connected to the natural gas network, with the proportion varying by state and territory, as shown in the table below. When including connections to LPG, nearly 70% of households have a connection to gas used for cooking and heating. Overall, it is estimated that there are over 18 million residential gas appliances[20].

On average, residential and commercial unit gas prices are considerably cheaper than unit electricity prices:[21]

- In June 2020, residential gas prices in Australia averaged A$0.11 per kWh, compared to residential electricity prices averaging A$0.34 per kWh.
- Business gas prices in Australia averaged A$0.08 per kWh, compared to business electricity prices of A$0.20 per kWh.

State/Territory	Percentage of homes connected to gas
ACT	85%
NSW	42%
QLD	10%
SA	57%
TAS	5%
VIC	80%
WA	75%
Australia	**49%**

Table 3-1 Australian residential gas statistics by region[22]

The gas system also helps to manage peaks in demand from this sector, which are more prevalent in certain states and territories due to lower ambient temperatures in the winter. The graphic below shows that, in states with a higher proportion of homes connected to gas, gas system peaks are higher than electricity system peaks.

[20] Gas Vision 2050 – Delivering a clean energy future – September 2020

[21] GlobalPetrolPrices.com, accessed 11 March 2021. Note that business usage defined as 1 million kWh per year of gas and electricity; residential usage uses average household electricity consumption and 30,000 kWh a year for gas

[22] Energy Networks Australia, Reliable and clean gas for Australian homes, October 2017 https://www.energynetworks.com.au/resources/fact-sheets/reliable-and-clean-gas-for-australian-homes/

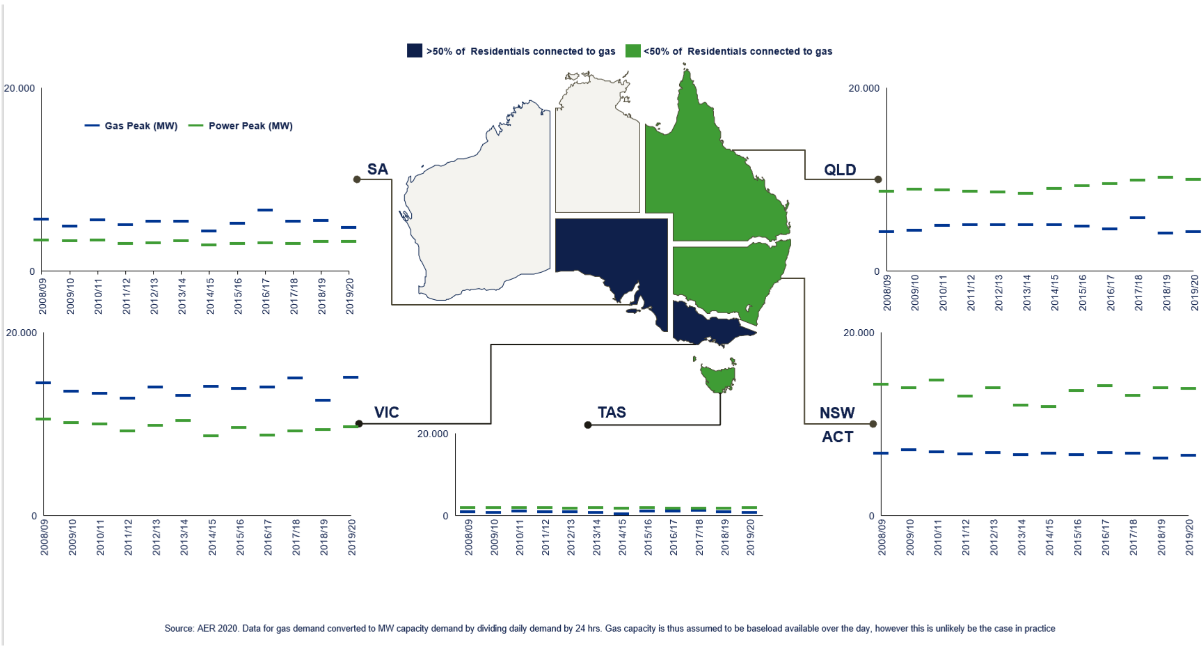


Figure 14 Yearly maximum gas and electricity demand peaks in certain states and territories[23]

Opportunities for renewable and decarbonised gases

The main opportunity for renewable and decarbonised gases in this sector is to allow households, commercial premises and public sector buildings to continue to use energy in a similar way to today, without the associated carbon footprint:

- In the case of blended or 100% renewable or decarbonised methane, no changes to residential or commercial appliances are needed.
- For blending of up to 10% hydrogen, it is most likely that no changes to residential "Type A" appliances are needed, although some larger "Type B" appliances may need modification. Domestic and light commercial appliances are classed as Type A appliances (e.g. boilers, cookers). Type B appliances largely refer to heavy commercial and industrial appliances i.e. non-standard installations. Hydrogen blending therefore allows early emission savings to occur, whilst 100% conversions are prepared.
- 100% hydrogen conversion would require existing residential and commercial gas appliances to be converted, as the neighbourhood switches over. Any disruption at the time of network conversion could be reduced by installing hydrogen-ready appliances in advance of network conversion, which can run on methane and which are then quickly modified (typically less than one hour per device) to run on 100% hydrogen during the conversion.

In all cases, households that enjoy the experience of cooking and heating with gas can continue to do so, and restaurant kitchens can also continue to benefit from gas cooking. The user experience essentially stays the same as today.

[23] AER 2020 peak demand Gas and Power data. Data for gas demand converted to MW capacity demand by dividing daily demand by 24 hrs. Gas capacity is thus assumed to be baseload available over the day, however this is unlikely be the case in practice. Western Australia and Northern Territories data not available so not represented in this graphic, ACT as part of combined NSW/ACT region

Key issues for a transition

The biggest issue for a transition in residential, commercial and public sector buildings is the need to replace appliances in the case of a conversion to 100% hydrogen. This means that large numbers of hydrogen (including hydrogen-ready) appliances need to be available in good time, which could involve a mix of domestic manufacturing and imports.

There may also need to be changes to pipework in the building, gas meters, service pipework and means to ensure adequate ventilation.

Each area would also need to convert wholesale to hydrogen at the same time – it would not be possible for half the houses on the street to stay on methane. Consumers either have to accept 100% hydrogen or stop using gas altogether.

These issues do not apply to 100% renewable or decarbonised methane supply options, where no changes to buildings or appliances are needed.

3.4.2 Industry

The role of gas today

The figure below shows the industrial and commercial systems which use gas and the output from the system.

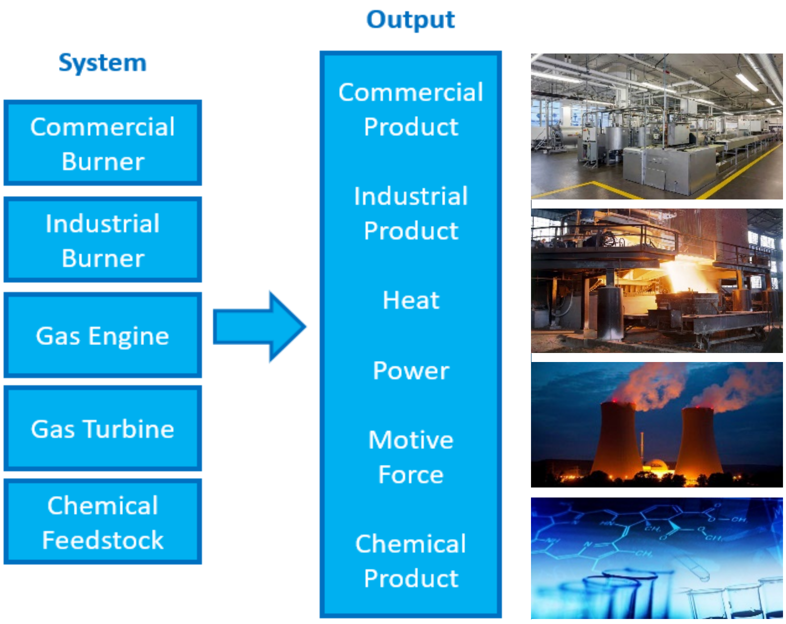


Figure 15 Key Industrial Gas Uses

Industry today uses natural gas predominantly in burners, gas engines and turbines. It also uses natural gas for space heating and as a feedstock. The biggest industrial users of natural gas are shown in Figure 16 below.[24]

[24] Australian Government, Department of Industry, Science, Energy and Resources, Australia Energy Statistics 2020, Table F https://www.energy.gov.au/publications/australian-energy-update-2020

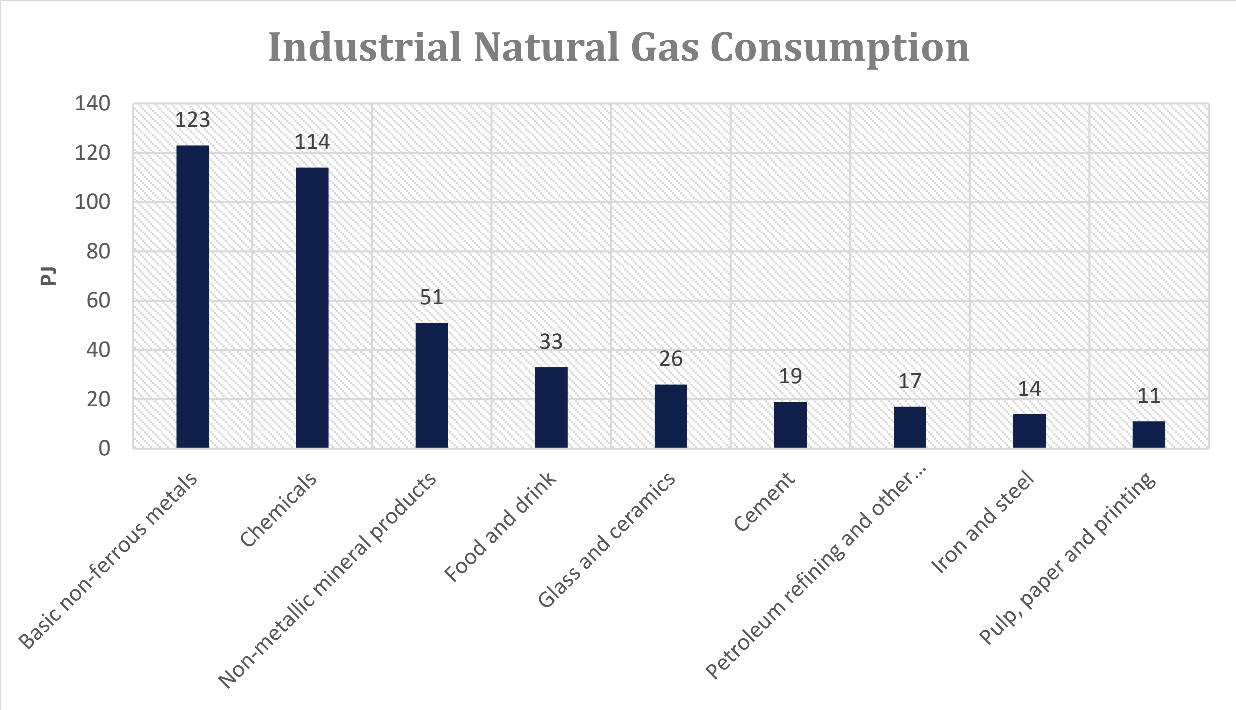


Figure 16 Annual Industrial Gas Consumption

Overall, natural gas accounts for around 35% of energy consumption in manufacturing.[25]

Opportunities for renewable and decarbonised gases

Gaseous energy is particularly important for certain industrial sectors and processes, in particular:

- For the production of high-temperature heat;
- For the generation of a flame, where industrial processes require direct exposure to flames;
- As a chemical feedstock.

Hydrogen has the potential to be used in industrial processes, for example in refineries that currently use methane. Fuel switching to hydrogen is seen in many studies as essential to achieving net zero in industry, working alongside efficiency, electrification, CCS and the generation of negative emissions through bioenergy with CCS. For example, a recent report for the UK's Climate Change Committee concluded that almost 20% of industrial emissions abatement could be achieved through hydrogen, with a similar proportion from industrial electrification.[26]

In other industrial sectors, for example the production of ammonia, where hydrogen is already used, the main opportunity is to replace high-carbon fuels with low-carbon hydrogen – without the need for process or equipment changes at the industrial facility itself.

Key issues for a transition

The key challenge for industrial transition will be the impact of both hydrogen blends and 100% hydrogen on industrial burners, engines, turbines, pipework and other plant and equipment. In some cases, equipment may not be so sensitive, or adjustments to burner control systems may suffice for blending, but otherwise it is likely that units would need to be replaced.

[25] Australian Government, Department of Industry, Science, Energy and Resources, Australia Energy Statistics 2020, Table F https://www.energy.gov.au/publications/australian-energy-update-2020

[26] Element Energy, Deep-decarbonisation pathways for UK industry: A report for the Climate Change Committee, November 2020 https://www.theccc.org.uk/publication/deep-decarbonisation-pathways-for-uk-industry-element-energy/

Using hydrogen may also affect the heat transfer within the industrial process, which may need to be redesigned (e.g. cement kilns). This is due to different emissivity of hydrogen flames compared to natural gas flames.

Changes to industrial processes would be unlikely to be needed for biomethane or synthetic methane, although existing Wobbe limits would need to be maintained.

3.4.3 Power generation and sector coupling

The role of gas today

In 2019, gas generated 21% of Australian electricity, and this proportion varies greatly by state and territory, as shown in the following chart.[27]

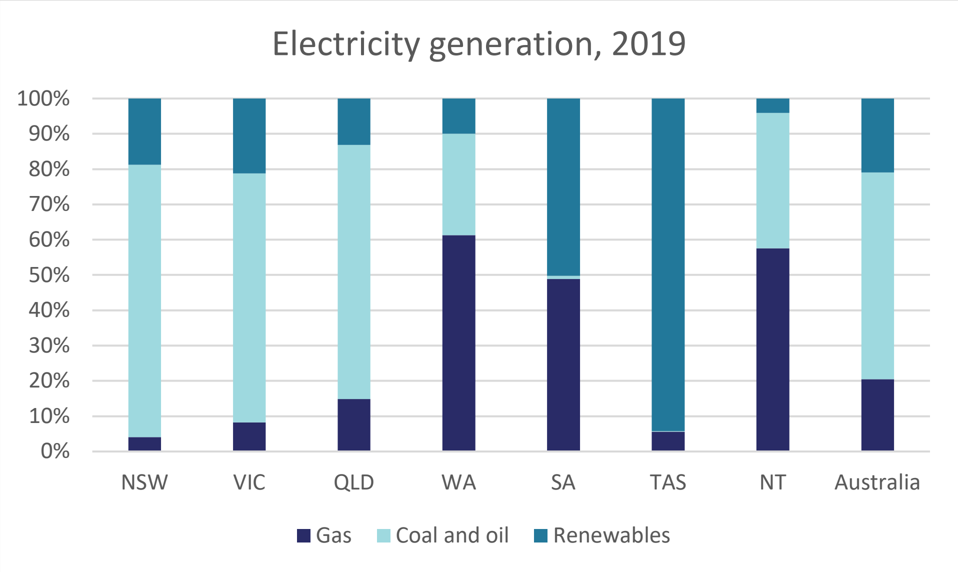


Figure 17 Australia State & Territory Electricity Generation by Fuel Type

The chart shows that in certain regions – Western Australia, South Australia and Northern Territory – gas accounts for around 50-60% of electricity generation. Although renewables are growing steadily, for the regions where gas-fired power generation is lower, coal is the main alternative (with the exception of Tasmania).

Gaseous power generation is likely to remain an important part of the Australian electricity system, supporting renewables in the progressive replacement of coal:

- Gas-fired power generation can provide peaking power for long periods of time, far longer and at lower cost than battery storage, helping to manage seasonal variations in demand and renewable generation.
- Gas can also provide resilience, helping the electricity system to accommodate short-term hourly, daily and weekly fluctuations in renewable generation.

Opportunities for renewable and decarbonised gases

Hydrogen power generation can perform the same role as natural gas power generation, able to be used for both peaking and baseload plants. It is likely that, as the share of renewables in the mix increases, the need for baseload plants will decline, and in which case hydrogen is ideally suited to play a peaking role[28].

[27] Department of Industry, Science, Energy and Resources, Australian Energy Statistics, Table O, September 2020 https://www.energy.gov.au/publications/australian-energy-update-2020

[28] DNV, Hydrogen in the electricity value chain, 2019 https://www.dnv.com/publications/hydrogen-in-the-electricity-value-chain-141099

The low carbon alternatives to hydrogen power generation are generally post-combustion CCS. It is likely that there will be a role for both post-combustion CCS and hydrogen power generation, with the economics of hydrogen generation improving relative to CCS at lower load factors. CAPEX costs, and access to suitable CO_2 stores can be problematic for power generation units considering a CCS option.

The other benefit of hydrogen in the power sector is its ability to provide sector-coupling services:

- Hydrogen from the electrolysis of water brings together low-cost renewable generation with uses in other sectors that may be more difficult to electrify, such as heavy transport, industry and some residential use.
- Hydrogen can also provide an effective long-term storage option for renewable electricity during periods of excess generation or low electricity prices.

Key issues for a transition

Similar to industrial equipment, power sector turbines may be sensitive to blends of hydrogen. The ability to store hydrogen at scale, to enable on-demand power generation, will also be important

Biomethane and synthetic methane are unlikely to have any impacts, subject to the same Wobbe qualification referred to in the industry section above.

Capacity markets in power and gas may need to be comparable to facilitate sector coupling and unlock the value of hydrogen as a store for variable renewables for users.

3.4.4 Transport

The role of gas today

The use of gas in the transport sector is limited today, with only a small number of public Liquified Natural Gas (LNG) and Compressed Natural Gas (CNG) refuelling stations across Australia – most CNG fleets have their own private refuelling stations.

Opportunities for renewable and decarbonised gases

Firstly, renewable and decarbonised methane offers a considerable opportunity to largely decarbonise heavy goods vehicles (HGVs) and bus fleets, reducing air pollution at the same time. CNG and LNG fuelled HGVs and buses are well established in many countries, and, due to the lower fuel cost, payback periods are typically just a few years. Trials have shown that CNG and LNG, if fuelled by biomethane, offer well-to-wheel carbon savings of 76-81% when compared to diesel, together with air quality benefits.[29] They can also benefit from use of the existing gas network, enabling fuelling stations to be built out at scale, with purchase of a green gas certificate to match the renewable and decarbonised methane injected elsewhere into the network.

Secondly, hydrogen is a zero-emission fuel at point of use, that has a number of advantages over batteries for certain types of transport:

- For **HGVs**, hydrogen has a far lower weight than batteries, meaning that payloads are not affected. Hydrogen HGVs also have longer range and quicker fuelling times.
- For **buses**, hydrogen offers longer range and quicker fuelling times, which is advantageous if the bus fleet is heavily utilised.

[29] Cenex, Dedicated to Gas: An Innovate UK Research Project to Assess the Viability of Gas Vehicles, October 2019 https://www.cenex.co.uk/case-studies/dedicated-to-gas/

- For **high utilisation fleets**, such as public service vehicles (police, ambulances etc) or taxis, charging times for battery powered solutions are often unacceptable.
- For **forklift trucks** and other heavily utilised warehouse/port machinery, hydrogen offers faster fuelling, reducing the amount of downtime for the vehicles.
- For **rail**, hydrogen trains can operate on non-electrified lines, with a longer range than batteries.
- In the **maritime** sector, similar benefits apply. For large container ships, hydrogen in the form of ammonia is a promising fuel, taking up a smaller space on the ship than alternatives.
- In the **aviation** sector, particularly for short haul, hydrogen fuel cells are currently being tested.
- Hydrogen also has potential for **cars and light vans**, with longer range and quicker refuelling times, but given the pace of battery electric vehicle and infrastructure development, the current view is that hydrogen will not be used extensively in this transport sector.

Key issues for a transition

There are several issues for renewable and decarbonised gases in transport, some of which are also cross-sectoral issues:

- Green gas certificates will be needed if the renewable and decarbonised methane is injected into the network somewhere else, which is how biomethane in bus and HGV fleets is generally organised in Europe. (A general renewable and decarbonised gas sustainability scheme is required across sectors, and this is covered elsewhere in the plan.)
- Hydrogen vehicles are currently being developed with fuel cells that require very high purity hydrogen (99.99999%). This requirement tends towards onsite electrolysis, or trucked hydrogen, for fuelling stations. Hydrogen that has been transported through a gas grid would tend to require additional purification and compression at the fuelling station.
- A nationwide hydrogen and/or methane refuelling network is required to enable long distance road transport. Shorter distance return-to-base vehicles will not need this.
- Vehicle manufacturers need to scale-up production of CNG/LNG trucks, and hydrogen trucks will need to move from a niche to a mainstream product, with economies of scale leading to cost reductions.
- Blending of hydrogen into the network would have implications for CNG engines, which may prevent CNG fuelling stations from being included within blended parts of the network. (This is a cross-sectoral issue from blending.)

4 DELIVERING THE PLAN

4.1 Plan Structure

The plan considers how to meet the three objectives for both renewable and decarbonised methane and hydrogen. It is considered prudent to plan for a mix of renewable and decarbonised methane and hydrogen conversion, and we recommend a specific project to work with renewable and decarbonised methane and hydrogen producers (and the electricity grid operators) to determine areas that might be most suitable for each pathway – essentially, this is a fuel supply plan for each of renewable and decarbonised hydrogen and renewable and decarbonised methane, but determined through a joint approach.

The plan focuses on the actions required from gas pipelines and distribution networks. Most of these are for distribution networks, but there are a number of joint transmission and distribution actions, and some specific actions for transmission pipelines, which are detailed in a separate table for ease of reference.

We subsequently detail the actions required from outside organisations, including regulatory activities, market development, end-user appliances and future fuels.

The plan is split in the following ways:

- Cross-cutting actions (Section 4.2) – Several key actions that are needed for both renewable and decarbonised methane and renewable and decarbonised hydrogen and which would benefit from a joint approach.
- Renewable and decarbonised methane Plan (Section 4.3) - The actions required to meet the three objectives for renewable and decarbonised methane, broken down by tenet into five-year blocks.
- Renewable and decarbonised hydrogen Plan (Section 4.4) - The actions required to meet each of the three objectives for hydrogen, including noting the activities that are common to all objectives, broken down by tenet into five or ten-year blocks.
- Actions for each End-Use Sector (Section 4.5) - The actions for both renewable and decarbonised methane and renewable and decarbonised hydrogen mapped across each end-use sector, broken down by tenet.
- Actions required for transmission pipelines (Section 4.6) - A separate table covering the key actions required for transmission pipelines.
- Key Actions for Outside Organisations (Section 4.7) - The key actions needed from organisations outside of the networks, in particular, regulatory and market development activities.

Please note that it is inevitable that there is some repetition in the activities set out in the tables below. The plan does not determine the balance of renewable and decarbonised hydrogen and methane to be taken in each network but sets out the pathway to each objective.

Chapter 5 describes each of the activities in more detail; Chapter 6 covers the regulatory changes in greater depth; and Chapter 7 sets out key risks to delivery.

One important aspect is the interface between national and state/territory activities. This is written as a national plan, but many of the activities and regulatory changes may need to be replicated in each state/territory. Ideally, changes should be coordinated as far as possible, with strong regulatory cooperation across states and territories.

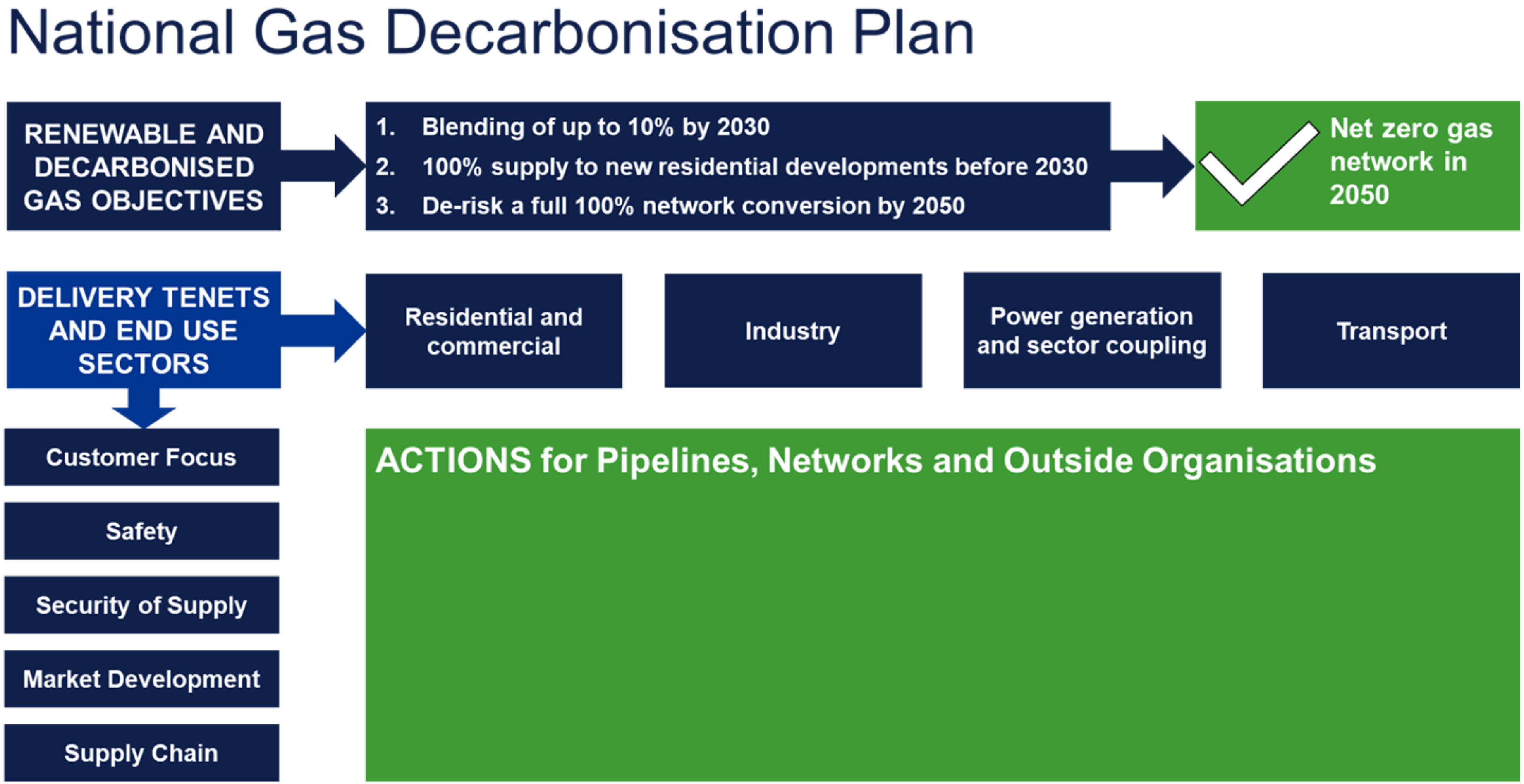


Figure 18: National Gas Decarbonisation Plan Structure

4.2 Cross-cutting actions

There are several important actions that are needed for renewable and decarbonised methane and hydrogen, and combinations of the two, and which would best be delivered through a joint approach. If tackled together, these cross-cutting actions can help to provide coherence to the overall transition to renewable and decarbonised gases.

4.2.1 Engagement

Public engagement, including in some cases with land and property developers, will be needed for individual renewable and decarbonised methane, hydrogen blending, 100% hydrogen trials and 100% hydrogen conversion projects. But focusing only on individual projects, even if they are major, risks blurring the message that gas networks will become net zero overall. It may also lead to questions about why hydrogen is deployed in some areas and renewable and decarbonised methane in others.

In parallel with individual project engagement, it is important to build on the existing Gas Vision 2050 work and provide a joint narrative across pipelines and networks, showing how individual projects fit into the wider transition, and also setting out where renewable and decarbonised methane and hydrogen may be most suitable. The engagement narrative should also show how hydrogen can support the growth of renewable electricity generation, how biomethane can make good use of waste feedstocks, and the potential of synthetic gases. This approach would also help engagement with renewable and decarbonised gas producers.

The engagement would also be informed by the joint renewable and decarbonised hydrogen and methane planning and the business case development, as set out below.

4.2.2 Joint renewable and decarbonised hydrogen and methane planning

As mentioned above, with varying renewable electricity, biomethane feedstock, CCS availability and other factors in different regions, optimal renewable and decarbonised gas supply solutions will differ by area. In order to take account of this, and ensure full coordination with other sectors, including electricity networks, it makes sense to plan the transition holistically. Joint planning would include the following issues (and many more):

- Renewable and decarbonised gas production potential in different regions, including electricity, water and other feedstocks, and the fit with regional demand profiles.
- Renewable and decarbonised gas storage potential in different regions.
- Optimal ways to increase storage capacity where needed.
- The optimal balance of network capacity increases, including gas pipelines and electricity transmission lines.
- The role of CCS in certain regions, especially where CCS projects are being developed already.
- Relative renewable and decarbonised hydrogen and methane production cost trajectories.

Joint planning will also help gas pipelines and networks to provide a coherent view to external stakeholders, helping to build support for individual projects.

4.2.3 Business case

Ultimately, markets need to be developed for renewable and decarbonised gases, as they have been for renewable electricity generation. Although there is growing demand from some consumers for green gas certificates, market incentives are likely to be needed to enable a full transition.

A joint business case should therefore be developed for renewable and decarbonised methane and hydrogen, complementing the joint planning described above, to demonstrate to outside organisations how renewable and decarbonised methane and hydrogen can be developed and substantial emissions reductions achieved cost-effectively.

Combined, these three cross-cutting actions would mean that pipelines and networks can engage external stakeholders, including renewable and decarbonised gas producers, electricity networks, government and consumers, with a practical and cost-effective set of pathways that are relevant for different regions. This can underpin the individual project actions and engagement.

4.3 Renewable and Decarbonised Methane Plan

Renewable and decarbonised methane is very similar to natural gas and can meet gas composition standards, although biogas may need to be processed to conform to the required specification. Raw renewable and decarbonised methane sources, such as biogas and landfill gas, may not meet current gas specifications when first produced. Processing is generally required to ensure that the gas is compliant with the relevant standards (AS4564) for natural gas to ensure the gas is safe to use. This isn't unlike the existing gas industry, in which raw gas from underground is processed before being made publicly available.

Sometimes, these raw gases from biological sources contain additional constituent components which are not currently considered by gas specification standards. An example of this is siloxanes, which are produced from some specific biogas or landfill gas feedstocks. If present, these constituent components typically need to be removed during the upgrading process. Alternately, if acceptable upper limits can be identified, these can be considered as additions to current gas specification standards, minimising the need for the cost of absolute removal.

Once the gas meets the specification, blending of renewable and decarbonised methane with natural gas at any level does not pose technical issues to the network assets or the consumer, and therefore can deliver emissions savings quickly and progressively – in the same way that renewable electricity is 'blended' into the electricity grid. However, renewable and decarbonised methane is different from natural gas supplies in the following respects:

- The gas network will need to be managed differently as there are likely to be multiple small entry points rather than a few large entry points into a transmission system
- The renewable and decarbonised methane can be injected into the gas network if a pipeline is available or collected by tanker to an injection point elsewhere
- For synthetic methane specifically, it may be produced from renewable hydrogen and CO_2 captured from the air or biogenic CO_2, and could be a solution to the decarbonisation of gas networks, although the energy required for production would need to be considered
- For biomethane specifically, it is produced from organic material that is broken down in an anaerobic digester, so it is a low-carbon gas. The output from the digester is biogas and this needs to be cleaned up to form grid quality biomethane – the clean-up depends upon the contaminants and chemistry of the organic feedstock. The biomethane output tends to be at a constant flow as anaerobic digestion is an organic process and at fairly low pressures. It may also have seasonal variations in availability.

Objectives 1, 2 and 3 for the injection of renewable and decarbonised methane into the Australian networks have been combined in the table below. Security of supply during the transition could be assured using natural gas as a back-up if necessary, although at a cost to decarbonisation.

The main challenges for increasing quantities of renewable and decarbonised methane are around system operation.

The network actions need to be focused on the next decade, to enable scale up.

4.3.1 2021-2025: Blending and 100% preparation

The next five years will help networks to prepare for wider renewable and decarbonised methane uptake. Carrying out this set of actions by 2025 is essential to being able to meet the 2030 blending objective, and from this perspective, the earlier that activities can be completed in a robust manner, the better:

- **Customer focus:** Public engagement on the benefits of green gas needs to be accompanied by ensuring that the billing regime is accurate and green gas certificates made available for purchase.
- **Safety:** Existing methane gas quality specification needs to be updated to consider additional constituent components found in some forms of renewable and decarbonised methane.
- **Security of supply:** A strategy for renewable and decarbonised methane supply and storage, together with natural gas back up during the transition, will be needed (as mentioned below this should be carried out as part of a joint approach to planning renewable and decarbonised hydrogen and methane transitions). Network modelling and network entry improvements will need to be carried out to facilitate more renewable and decarbonised methane producers to connect, and System Operation will need to be reviewed.
- **Supply chain:** Training facilities and material will be needed to be developed for the workforce. The equipment supply chain will need to be educated and a biomethane business case developed.

4.3.2 2026-2030: Scaling up

The latter half of the 2020s should see more renewable and decarbonised methane production connected to networks, and higher blends of renewable and decarbonised methane in some areas, with the aim of 100% renewable and decarbonised methane in certain districts:

- **Customer focus:** Public engagement and a customer-facing roll out strategy will be needed.
- **Safety:** Safety cases will need to be updated.
- **Security of supply:** Networks will need to engage with green gas production and storage developers and develop System Operation for a wider roll out.
- **Supply chain:** Training facilities and material will need to be maintained and rolled out for the workforce. The equipment supply chain will become more mature.

	2021-2025	2026-2030	2030s and 2040s
Renewable and decarbonised methane deployment for objectives 1, 2 and 3			
CUSTOMER FOCUS	• Public engagement • Develop customer facing roll out strategy • Billing for blending with natural gas • Conduct and optimise renewable and decarbonised methane demonstration work • Consumers able to buy green gas certificates for renewable and decarbonised methane	• Public engagement	
SAFETY	• Update current methane gas quality specification standard AS 4564 to consider additional constituent components found in some renewable and decarbonised methane • Further research required into possibility of components in renewable and decarbonised methane masking the odorant added by the networks.	• Implement learning from validation of safety in trials by updating risk assessments and safety cases	
SECURITY OF SUPPLY	• Strategy for renewable and decarbonised methane supply, security and availability of feedstock, daily and seasonal storage, and natural gas backup • Network modelling • Network entry • Network liaison with System Operator on network management issues • Engage with green gas production and storage developers for roll out	• Engage with green gas production and storage developers for roll out • Implement learning from trials and develop mature network and system operations for roll out	• Joint roll-out of renewable and decarbonised methane and hydrogen
SUPPLY CHAIN	• Develop training facilities and material for the workforce to raise awareness of production sites, different potential contaminants from biomethane feedstocks, and monitoring/audit gas entry measurement systems • Develop business case for renewable and decarbonised methane (alongside hydrogen) to demonstrate to outside organisations how renewable and decarbonised methane can be developed and substantial emissions reductions achieved cost-effectively	• Maintain and roll out training materials. • Seek diversity and competition in supply chain provision.	

Table 4-1 Australia's Decarbonisation Plan for renewable and decarbonised methane in gas networks

	2021-2025	2026-2030	2030s and 2040s
Transmission pipeline activities for renewable and decarbonised methane			
CUSTOMER FOCUS	• Public and directly connected customer engagement, including distribution networks • Custody transfer measurement systems • Consumers able to buy green gas certificates for renewable and decarbonised methane	• Public and directly connected customer engagement, including distribution networks	
SAFETY	Update current methane gas quality specification standard AS 4564 to consider additional constituent components found in some renewable and decarbonised methane	• Implement learning from validation of safety in trials by updating risk assessments and safety cases	
SECURITY OF SUPPLY	• Strategy for renewable and decarbonised methane supply, daily and seasonal storage, and natural gas backup • Network modelling • Network entry • System operator and network management • Engage with green gas production and storage developers for roll out	• Engage with green gas production and storage developers for roll out • Implement learning from trials and develop mature network and system operations for roll out	• Joint roll-out of renewable and decarbonised methane and hydrogen
SUPPLY CHAIN	• Develop training facilities and material for the workforce to raise awareness of production sites, potential contaminants from biomethane feedstocks, and monitoring/audit gas entry measurement systems • Develop business case for renewable and decarbonised methane (alongside hydrogen)	• Maintain and roll out training materials • Seek diversity and competition in supply chain provision	

Table 4-2 Australia's Decarbonisation Plan for renewable and decarbonised methane in gas pipelines

4.4 Renewable and Decarbonised Hydrogen Plan

Hydrogen is more technically challenging than renewable and decarbonised methane and there are specific issues to be overcome for blending with natural gas (Objective 1), developing 100% hydrogen new networks (Objective 2) and for conversion of natural gas networks to 100% hydrogen (Objective 3). Hence the list of actions required for hydrogen is longer than for renewable and decarbonised methane.

The list of actions in the tables below may appear to be repetitive, but they will be different for each objective. For example, network modelling is required for all three objectives under security of supply, but the network modelling activity will be different for each one. For objective 1, the existing network models for natural gas will need to incorporate 10% hydrogen but the network will need to deliver the same amount of energy so the overall flows will increase by about 3%. For objective 2, the network models will be for a new development so these will be new models. For objective 3, the existing natural gas models will need to be recalculated as the flows, pressures and gas velocities of 100% hydrogen will be greater than natural gas – this may result in some reinforcement of the pipework to be required prior to conversion.

4.4.1 2021-2025: Blending trials and 100% preparation

The first five years to 2025 are about blending trials and preparing for the 100% transition – this is when all the preparatory work for blending, 100% hydrogen trials with new networks and conversion of existing networks to 100% hydrogen will take place. Carrying out this set of actions by 2025 is essential to being able to meet the 2030 blending and 100% hydrogen trials objectives, and from this perspective, the earlier that activities can be completed in a robust manner, the better:

- **Customer focus:** Public engagement on the benefits of green gas needs to be accompanied with engagement on hydrogen conversion, much of which is underway, including taking on board feedback from the interim blending and trials steps. Accurate billing and measurement are also essential. Practical trials will also be needed to demonstrate to consumers that hydrogen works well. Purification solutions for hydrogen delivered via networks to be used in fuel cell vehicles should also be developed. Engagement with industry should also commence.

- **Safety:** 10% blended and 100% hydrogen gas quality specifications will be needed, together with work to assess existing Type A and B appliances. Safety risk assessments for blending and 100% hydrogen need to be completed and workforce training started. Specific consideration of transmission pipelines is also needed. Liaison with emergency responders to outline the differences in properties between methane and hydrogen.

- **Security of supply:** A strategy for hydrogen supply and storage, including maintaining the natural gas parts of the network during the transition, will be needed (as mentioned above this should be carried out as part of a joint approach to planning renewable and decarbonised hydrogen and methane transitions). Network modelling and network entry improvements will need to be carried out to facilitate more hydrogen producers to connect, and System Operation will need to be reviewed for both 10% and 100%. Options for hydrogen production and storage for trials, including business models, need to be agreed.

- **Supply chain:** Training facilities and material will be needed for the workforce, and engagement needs to take place with manufacturers of hydrogen equipment, including for networks and end-user hydrogen-ready appliances. A business case also needs to be developed.

4.4.2 2026-2030: Blending roll-out and 100% trials

In this period, 10% hydrogen blending is rolled out more widely, the first 100% trials in new property developments take place, and the first limited conversions of existing networks start. Physically, blending will not be a uniform 10% nationwide, as it will depend on hydrogen production locations and other factors. However, together with renewable and decarbonised methane, blending of renewable and decarbonised gases overall could be higher than 10% in some areas, enabling an average 10% to be achieved nationwide:

- **Customer focus:** There will need to be further engagement with industry and power generators, including small scale gas engine, burner and turbine users to trial equipment. A customer-facing roll-out strategy, based on learnings from trials, should be developed.
- **Safety:** Safety cases need to be updated for blends and 100% and safe operation for industrial and power generators should be developed.
- **Security of supply:** There will need to be further engagement with production and storage developers to ensure security of supply as blending and 100% developments are increased. With 10% blends, deblending or other options for gas engine and turbine users not ready for hydrogen may also need to be developed. Hydrogen transport network refuelling solutions are also essential if the transport sector is not just to be fuelled from onsite production.
- **Supply chain:** Workforce training needs to continue and engagement with equipment and appliance manufacturers should ensure that sufficient volumes of hydrogen and hydrogen-ready appliances are being manufactured or imported at scale.

4.4.3 2031-2040 and 2041-2050: Network conversion and roll-out completion

In the 2030s, conversion to 100% hydrogen is taking place in earnest across the network, and more new developments are being connected to hydrogen. Public engagement remains critical as wider conversion pilots are carried out, and safety cases need to be updated for wider roll-out. Hydrogen production and storage capacity needs to be ramped up, which would include renewable generation capacity for green hydrogen and CCS capacity for blue hydrogen production. Hydrogen training becomes a business-as-usual activity for networks, and the supply chain needs to be manufacturing hydrogen equipment and appliances at scale.

	2021-2025	2026-2030
Objective 1 – 10% hydrogen blending		
CUSTOMER FOCUS	• Public engagement including taking on board feedback from the forthcoming trials • Billing for blending with natural gas • Ensure existing customer meters can measure 10% H_2 blend • Conduct 10% H_2 blending consumer trials • Develop customer facing roll out strategy based on learning from trials • Consumers able to buy green gas certificates for renewable and decarbonised hydrogen	• Public engagement • Roll out 10% H_2 networks
SAFETY	• 10% H_2 gas quality specification • 10% H_2 odorants, odorization and flame colourants • Validate combustion is safe for type A & B appliances with 10% H_2 • Develop safe envelope of operation for hydrogen grid entry units including mixing, control systems, backup storage etc • Hydrogen/gas detection equipment • Gas fitter and network training for 10% H_2 blend in the network and 100% H_2 at trial production facility • Develop safety case for 10% H_2 blend • Consider suitability of 10% (or lower) blend for transmission pipelines, including required changes to pipeline regulation and standards • Liaison with emergency responders to outline the differences in properties between methane and hydrogen.	• Implement learning from validation of safety in trials by updating safety cases
SECURITY OF SUPPLY	• Strategy for network support for hydrogen production, daily and seasonal storage and natural gas backup, including entry points – to support discussions with gas production and storage • Network modelling • Network entry • 10% H_2 flow measurement • Network liaison with System Operator on network management issues for 10% blends • Engage with green gas production and storage developers for roll out of blending, including on network modelling and entry points, with networks sharing data with producers to help them decide where to produce and inject into the network	• Implement learning from trials & develop roll out operations • Develop deblending or other options for gas engine and gas turbine users not ready for H_2, including considering cost-effectiveness

	2021-2025	2026-2030
Objective 1 – 10% hydrogen blending		
SUPPLY CHAIN	• Develop training facilities and material for the workforce involved in handling 100% hydrogen at the production site and 10% blend in the network • Engage with manufacturers and suppliers of hydrogen equipment such as electrolysers, valves, measurement systems etc. • Develop blending facility for injection of 10% hydrogen, including to ensure that blend is suitably controlled at the injection point to ensure homogenous injection • Developing a business case for blending (and 100% conversions alongside renewable and decarbonised methane) to demonstrate to outside organisations how renewable and decarbonised hydrogen can be developed and substantial emissions reductions achieved cost-effectively	• Continue training workforce during roll out and extend training facilities to cover 100% H_2 in new property developments (objective 2) • Continue engagement with manufacturers and suppliers of hydrogen equipment such as electrolysers & valves etc for roll out of 10% hydrogen blend • Continue development and improvement of blending facility for hydrogen injection point • Develop Type B appliances conversion kits for roll out

Table 4-3 Australia's Decarbonisation Plan for hydrogen in gas networks – Objective 1

	2021-2025	2026-2030
Transmission pipeline activities for Objective 1 - 10% hydrogen blending		
CUSTOMER FOCUS	• Public and directly connected customer engagement, including distribution networks • Custody transfer measurement systems • Consumers able to buy green gas certificates for renewable and decarbonised hydrogen	• Public and directly connected customer engagement, including distribution networks
SAFETY	• 10% H_2 gas quality specification • Develop safe envelope of operation for hydrogen grid entry including mixing, control systems, backup storage etc • Hydrogen/gas detection equipment • Gasfitter and network training for 10% H_2 blend and 100% H_2 at trial production facility • Develop safety case for 10% H_2 blend • Offline trials of hydrogen blends in transmission pipelines • Define safe upper limit for hydrogen blends in transmission pipelines, with reference to the AS 2885 standard • Liaison with emergency responders to outline the differences in properties between methane and hydrogen.	• Implement learning from validation of safety in trials by updating safety cases

	2021-2025	2026-2030
Transmission pipeline activities for Objective 1 - 10% hydrogen blending		
SECURITY OF SUPPLY	• Strategy for hydrogen production, daily and seasonal storage and natural gas backup • Network modelling, including capacity (given hydrogen's lower volumetric energy density), storage (linepack and seasonal), the need to maintain the resilience of the existing natural gas network, and the interaction with distribution network injection • Network entry • System operator and network management • Engage with producers to ensure sufficient hydrogen production and storage facilities (including CCS for blue H_2) for trials and roll out. This includes linepack, large-scale hydrogen storage to meet seasonal demand, and the sector coupling of green hydrogen and the electricity market	• Implement learning from trials and develop mature network and system operations for roll out • Develop deblending or other options for gas engine and gas turbine users not ready for H_2
SUPPLY CHAIN	• Develop training facilities and material for the workforce to raise awareness of production sites, potential contaminants, and monitoring/audit gas entry measurement systems • Engage with manufacturers and suppliers of hydrogen pipeline equipment such as valves, measurement systems etc. • Develop blending facility for injection of 10% hydrogen • Business case for blending renewable and decarbonised hydrogen (and methane)	• Maintain and roll out training materials • Continue engagement with manufacturers and suppliers of hydrogen pipeline equipment such as valves etc for roll out of 10% hydrogen blend • Continue development and improvement of blending facility for hydrogen injection point

Table 4-4 Australia's Decarbonisation Plan for hydrogen in Transmission pipelines – Objective 1

	2021-2025	2026-2030
Objective 2 – 100% hydrogen in new property developments		
CUSTOMER FOCUS	• Develop concept of how to establish 100% hydrogen in new property developments • Public engagement • Land and property developer engagement, including urban planners • Compatibility check of existing 100% H_2 meters and develop new ones if required • Billing (depending on H_2 purity) • Build a demonstration house/facility with hydrogen (indoors and outdoors) appliances for consumer interaction • Carry out 100% H2 trial in a new property development	• Public engagement • Engage with small-scale gas engine and gas turbine users to trial equipment • Engagement with industry • Roll-out new-builds with hydrogen • Develop trial H_2 transport refuelling solution
SAFETY	• 100% H_2 gas quality specification • Odorants, odorization and flame colourants • Assess hydrogen Type A and Type B appliances and develop as required for Australian market • Assess H_2 compatibility and knowledge gaps for all components in new-build networks • Develop safe envelope of operation for hydrogen grid entry units including control systems, backup storage etc • Gas detection equipment • Gasfitter & network training for 100% H_2 • Develop safety case for new 100% H_2 network • Assess need for extra safety equipment such as excess flow valves, ventilation etc • Work with industry to amend building codes/standards to account for 100% hydrogen developments. • Liaison with emergency responders to outline the differences in properties between methane and hydrogen.	• Implement learning from validation of safety in 100% hydrogen trials by updating safety cases
SECURITY OF SUPPLY	• Network modelling • Network entry • 100% H_2 flow measurement • Develop system operation and management of new network • Develop options for production and storage of H_2 for trials, maintaining security of supply for the trial • Develop H_2 business models for trial or as part of a trial	• Develop cross-cutting power/H_2 and renewable and decarbonised methane/H_2 concepts • Engage with hydrogen production and storage developers for roll out at new build developments • Implement learning from trials and develop mature network and system operations for roll out
SUPPLY CHAIN	• Develop training facilities and material for the workforce involved in handling hydrogen • Develop manufacturing capability with suppliers for hydrogen appliances, hydrogen meters, valves, tools etc for service in 100% H_2 for the trials. This could also include certifying imported appliances and other equipment for use in Australia • Developing a business case for 100% hydrogen (alongside renewable and decarbonised methane) to demonstrate to outside organisations how renewable and decarbonised hydrogen can be developed and substantial emissions reductions achieved cost-effectively.	• Continue training greater numbers of workforce to facilitate development of new build rollout • Engage with supply chain to encourage scalable production line capability for H_2 compatible components

Table 4-5 Australia's Decarbonisation Plan for hydrogen in gas networks – Objective 2

	2021-2025	2026-2030
Transmission pipeline activities for Objective 2 - 100% hydrogen in new property developments		
CUSTOMER FOCUS	• Public and directly connected customer engagement, including distribution networks • Engage with large-scale gas engine and gas turbine users to trial equipment • Custody transfer measurement systems	• Public and directly connected customer engagement, including distribution networks
SAFETY	• 100% H_2 gas quality specification • Develop safe envelope of operation for hydrogen grid entry including mixing, control systems, backup storage etc • Hydrogen/gas detection equipment • Develop safety cases for 100% H_2 • Offline trials of 100% hydrogen in transmission pipelines. • Liaison with emergency responders to outline the differences in properties between methane and hydrogen.	• Implement learning from validation of safety in trials by updating safety cases
SECURITY OF SUPPLY	• Strategy for hydrogen production, daily and seasonal storage • Network modelling, including capacity (given hydrogen's lower volumetric energy density), storage (linepack and seasonal), the need to maintain the resilience of the existing natural gas network, and the interaction with distribution network injection • Network entry • System operator and network management	• Engage with hydrogen production and storage developers for roll out • Implement learning from trials and develop mature network and system operations for roll out • Develop cross-cutting power/H_2 concepts
SUPPLY CHAIN	• Develop training facilities and material for the workforce to raise awareness of production sites, potential contaminants, and monitoring/audit gas entry measurement systems • Engage with manufacturers and suppliers of hydrogen pipeline equipment such as valves, measurement systems etc.	• Maintain and roll out training materials

Table 4-6 Australia's Decarbonisation Plan for hydrogen in transmission pipelines – Objective

	2021-2025	2026-2030	2031-2040	2041-2050
Objective 3 – 100% hydrogen conversion de-risking and roll out				
CUSTOMER FOCUS	• Public engagement • Billing (depending on H2 purity) • Compatibility check of existing 100% H_2 meters and develop new ones if required • Develop H_2 purification solution for fuel cell vehicles	• Public engagement including demonstration facility • Carry out consumer conversion trial for an isolated section of the network • Engage with industrial and power generation sectors • Engage with electricity network operators to ensure that electricity requirements needed for hydrogen production align with ISP and respective jurisdictional electricity plans • Integration of transport, water utilities and networks for green hydrogen production • Develop trial H_2 transport refuelling solution	• Public engagement • Carry out a conversion pilot in a regional setting taking customer learning from the conversion trial phase	• Public engagement • Roll out national 100% hydrogen conversion networks taking customer learning from the conversion pilot phase
SAFETY	• 100% H_2 gas quality specification • Odorants, odorization and flame colourants • Assess hydrogen-ready Type A and type B appliances and develop as required for Australian market • Gas detection equipment • Gasfitter training for 100% H_2 • Develop safety case for conversion to 100% H_2 network • Develop venting and purging policy/methods for conversion. • Liaison with emergency responders to outline the differences in properties between methane and hydrogen.	• Provide network support to the development of safe 100% hydrogen operations for industrial and power generator sectors	• Implement learning from validation of safety in conversion trials by updating safety cases for pilots	

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	2021-2025	2026-2030	2031-2040	2041-2050
Objective 3 – 100% hydrogen conversion de-risking and roll out				
SECURITY OF SUPPLY	• Network modelling • Network entry • 100% H_2 flow measurement • Develop conversion strategy including sectorisation, new transmission pipework, hydrogen production and storage and maintenance of natural gas during conversion • Develop system operation and management of converted network • Develop options for production and storage of H_2 for conversion trials • Develop H_2 business models for trial or as part of a trial	• Develop cross-cutting power/H_2 and renewable and decarbonised methane/H_2 concepts • Develop detailed conversion plans for pilot to ensure security of supply of natural gas and hydrogen during conversion • Deliver network investment required • Engage with producers to ensure sufficient hydrogen production and storage facilities (including CCS for blue H_2) for pilots and roll out. This includes linepack, large-scale hydrogen storage to meet seasonal demand, and the sector coupling of green hydrogen and the electricity market • Develop options for wider conversion, including joint planning with renewable and decarbonised methane	• Ramp up hydrogen production and storage (including CCS for blue H_2) facilities Include any learning from the conversion trial to the pilot phase	• Address any shortcomings that are apparent in the mature and sustainable commercial market
SUPPLY CHAIN	• Develop training facilities and material for the workforce involved in handling hydrogen • Develop manufacturing capability with suppliers for hydrogen appliances, hydrogen meters, valves, tools etc for service in 100% H_2 for the trials • Develop 100% hydrogen-ready Type A and Type B appliances (supply chain) Developing a business case for 100% hydrogen (alongside renewable and decarbonised methane) to demonstrate to outside organisations how renewable and decarbonised hydrogen can be developed and substantial emissions reductions achieved cost-effectively.	• Identify manufacturing capability for equipment needed for conversion process such as sectorisation valves, purging • Develop training facilities for converting natural gas networks to 100% hydrogen Engage with supply chain to encourage scalable production line capability for H_2 compatible Type A appliances and components, including import option	• Engage with supply chain to encourage scalable production line capability for H_2 ready components and appliances	

Table 4-7 Australia's Decarbonisation Plan for hydrogen in gas networks – Objective 3

	2021-2025	2026-2030	2031-2040	2041-2050
Transmission pipeline activities for Objective 3 - 100% hydrogen conversion de-risking and roll out				
CUSTOMER FOCUS	• Public and directly connected customer engagement, including distribution networks • Engage with large-scale gas engine and gas turbine users to trial equipment • Custody transfer measurement systems •	• Public and directly connected customer engagement, including distribution networks	• Public and directly connected customer engagement, including distribution networks	• Public and directly connected customer engagement, including distribution networks
SAFETY	• 100% H_2 gas quality specification • Hydrogen/gas detection equipment • Safety case for 100% H_2 • Offline trials of 100% hydrogen in transmission pipelines. • Liaison with emergency responders to outline the differences in properties between methane and hydrogen.	• Develop safe operations for industrial and power generator sectors	• Implement learning from validation of safety in trials by updating safety cases	
SECURITY OF SUPPLY	• Strategy for hydrogen production, daily and seasonal storage • Network modelling, including capacity (given hydrogen's lower volumetric energy density), storage (linepack and seasonal), the need to maintain the resilience of the existing natural gas network, and the interaction with distribution network injection • Network entry • System operator and network management	• Develop cross-cutting power/H_2 concepts • Engage with producers to ensure sufficient hydrogen production and storage facilities (including CCS for blue H_2) for trials and roll out. This includes linepack, large-scale hydrogen storage to meet seasonal demand, and the sector coupling of green hydrogen and the electricity market	• Ramp up hydrogen production and storage (including CCS for blue H_2) facilities	• Address any shortcomings that are apparent in the mature and sustainable commercial market

	2021-2025	2026-2030	2031-2040	2041-2050
Transmission pipeline activities for Objective 3 - 100% hydrogen conversion de-risking and roll out				
SUPPLY CHAIN	• Develop training facilities and material for the workforce to raise awareness of production sites, potential contaminants, and monitoring/audit gas entry measurement systems • Engage with manufacturers and suppliers of hydrogen pipeline equipment such as valves, measurement systems etc. • Business case for 100% renewable and decarbonised hydrogen conversion (alongside renewable and decarbonised methane)	• Maintain and roll out training materials	• Engage with supply chain to encourage scalable production line capability for H_2 ready components	

Table 4-8 Australia's Decarbonisation Plan for hydrogen in transmission pipelines – Objective 3

4.5 Actions for each end-use sector

The tables below categorise the actions required for each of the end-use sectors in the next five years, and then the second half of the 2020s, broken down by tenet – the majority of the actions are required in the next ten years. Many of the actions are cross-cutting. For transport, 10% hydrogen blend has been excluded as a practical option, given that we do not see CNG engines working on a 10% blend and there are no fuel cells currently operating on blends.

<table>
<tr><th>2021-2025</th><th>Residential and commercial</th><th>Industry</th><th>Power generation and sector coupling</th><th>Transport</th></tr>
<tr><td colspan="5">Renewable and decarbonised methane and hydrogen, all objectives</td></tr>
<tr><td rowspan="14">CUSTOMER FOCUS</td><td colspan="4">Public engagement (including land and property developers and urban planners for new-build 100% hydrogen trials)</td></tr>
<tr><td colspan="4">Develop customer facing roll out strategy for renewable and decarbonised methane</td></tr>
<tr><td colspan="4">Develop customer facing roll out strategy for blended and 100% hydrogen based on learning from trials</td></tr>
<tr><td colspan="4">Billing for blending/100% renewable and decarbonised methane and/or hydrogen with natural gas</td></tr>
<tr><td>Develop concept of how to establish 100% hydrogen in new property developments</td><td></td><td></td><td></td></tr>
<tr><td>Conduct and optimise renewable and decarbonised methane demonstration work</td><td></td><td></td><td></td></tr>
<tr><td colspan="4">Consumers able to buy green gas certificates for renewable and decarbonised methane and hydrogen</td></tr>
<tr><td colspan="3">Ensure existing customer meters can measure 10% H_2 blend</td><td></td></tr>
<tr><td>Conduct 10% H_2 blending consumer trials</td><td></td><td></td><td></td></tr>
<tr><td colspan="4">Compatibility check of existing 100% H_2 meters and develop new ones if required</td></tr>
<tr><td>Build a demonstration house/facility with hydrogen (indoors and outdoors) appliances for consumer interaction</td><td></td><td></td><td></td></tr>
<tr><td>Carry out 100% H2 trial in a new property development</td><td></td><td></td><td></td></tr>
<tr><td></td><td></td><td></td><td>Develop H_2 purification solution for fuel cell vehicles</td></tr>
<tr><td colspan="4"></td></tr>
<tr><td rowspan="6">SAFETY</td><td colspan="4">Update current methane gas quality specification standard AS 4564 to consider additional constituent components found in some renewable and decarbonised methane</td></tr>
<tr><td>Further research required into possibility of components in renewable and decarbonised methane masking the odorant added by the networks</td><td></td><td></td><td></td></tr>
<tr><td colspan="3">10% H_2 & 100% H2 gas quality specification</td><td></td></tr>
<tr><td>10% & 100% H_2 odorants, odorization and flame colourants</td><td></td><td></td><td></td></tr>
<tr><td colspan="3">Validate combustion is safe for type A & B appliances with 10% H_2</td><td></td></tr>
<tr><td colspan="3">Assess 100% hydrogen Type A and Type B appliances and develop as required for Australian market</td><td></td></tr>
</table>

<table>
<thead>
<tr><th>2021-2025</th><th>Residential and commercial</th><th>Industry</th><th>Power generation and sector coupling</th><th>Transport</th></tr>
</thead>
<tbody>
<tr><td rowspan="11">SAFETY CONT'D</td><td colspan="4">Develop safe envelope of operation for hydrogen grid entry units including mixing, control systems, backup storage etc</td></tr>
<tr><td colspan="4">Hydrogen/gas detection equipment</td></tr>
<tr><td colspan="4">Gasfitter and network training for 10% H_2 blend and 100% H_2</td></tr>
<tr><td colspan="3">Develop safety case for 10% H_2 blend</td><td></td></tr>
<tr><td colspan="4">Consider suitability of 10% (or lower) blend for transmission pipelines, including required changes to pipeline regulation and standards</td></tr>
<tr><td colspan="4">Develop safety case for 100% hydrogen</td></tr>
<tr><td colspan="4">Assess H_2 compatibility and knowledge gaps for all components in new-build networks</td></tr>
<tr><td colspan="4">Assess need for extra safety equipment such as excess flow valves, ventilation etc</td></tr>
<tr><td>Work with industry to amend building codes/standards to account for 100% hydrogen developments</td><td></td><td></td><td></td></tr>
<tr><td colspan="4">Develop venting and purging policy/methods for conversion</td></tr>
<tr><td colspan="4">Liaison with emergency responders to outline the differences in properties between methane and hydrogen.</td></tr>
<tr><td rowspan="11">SECURITY OF SUPPLY</td><td colspan="4">Strategy for renewable and decarbonised methane supply, security and availability of feedstock, daily and seasonal storage, and natural gas backup</td></tr>
<tr><td colspan="4">Strategy for network support for renewable and decarbonised hydrogen production, daily and seasonal storage (and natural gas backup), including entry points</td></tr>
<tr><td colspan="4">Network modelling</td></tr>
<tr><td colspan="4">Network entry</td></tr>
<tr><td colspan="4">Network liaison with System Operator on network management issues for 10% blends and 100% renewable and decarbonised methane and hydrogen</td></tr>
<tr><td>Develop options for production and storage of H_2 for trials, maintaining security of supply for the trial</td><td></td><td></td><td></td></tr>
<tr><td>Develop H_2 business models for trial or as part of a trial</td><td></td><td></td><td></td></tr>
<tr><td colspan="3">10% H_2 flow measurement</td><td></td></tr>
<tr><td colspan="4">100% H_2 flow measurement</td></tr>
<tr><td colspan="4">Engage with green gas production and storage developers for roll out for 10% blends and 100% renewable and decarbonised methane and hydrogen, including on network modelling and entry points. This includes ensuring sufficient linepack, and large-scale hydrogen storage to meet seasonal demand.</td></tr>
<tr><td colspan="4">Develop conversion strategy including sectorisation, new transmission pipework, hydrogen production and storage and maintenance of natural gas during conversion</td></tr>
<tr><td rowspan="4">SUPPLY CHAIN</td><td colspan="4">Develop training facilities and material for the workforce to raise awareness of renewable and decarbonised methane production sites, different potential contaminants for biomethane feedstocks, and how to monitor/audit gas entry measurement systems</td></tr>
<tr><td colspan="4">Develop training facilities and material for the workforce involved in handling 100% hydrogen at the production site and 10% blend or 100% in the network</td></tr>
<tr><td colspan="4">Engage with manufacturers and suppliers of hydrogen equipment such as electrolysers, valves, measurement systems etc.</td></tr>
<tr><td colspan="3">Develop blending facility for injection of 10% hydrogen, including to ensure that the blend is suitably controlled at the injection point to ensure homogenous injection</td><td></td></tr>
</tbody>
</table>

2021-2025	Residential and commercial	Industry	Power generation and sector coupling	Transport
SUPPLY CHAIN CONT'D	Develop manufacturing capability with suppliers for hydrogen appliances, hydrogen meters, valves, tools etc for service in 100% H_2 for the trials. This could also include certifying imported appliances and other equipment for use in Australia			
	Develop 100% hydrogen-ready Type A and Type B appliances (supply chain)			
	Develop business case for renewable and decarbonised methane and hydrogen to demonstrate to outside organisations how renewable and decarbonised methane and hydrogen can be developed and substantial emissions reductions achieved cost-effectively			

Table 4-9 2021-2025 activities for each end-use sector

2026-2030	Residential and commercial	Industry	Power generation and sector coupling	Transport
Renewable and decarbonised methane and hydrogen, all objectives				
CUSTOMER FOCUS	Public engagement for renewable and decarbonised methane and hydrogen			
	Roll out 10% H_2 networks			
		Engage with small-scale gas engine and gas turbine users to trial equipment		
		Engagement with industry	Engagement with power generation sector	
			Engage with electricity network operators to ensure that electricity requirements for hydrogen production align with ISP and respective jurisdictional electricity plans	
	Integration of transport, water utilities and networks for green hydrogen production			
	Roll-out new-builds with hydrogen			
	Carry out consumer 100% hydrogen conversion trial for an isolated section of the network or new network			
				Develop trial H_2 transport refuelling solution

<table>
<tr><th>2026-2030</th><th>Residential and commercial</th><th>Industry</th><th>Power generation and sector coupling</th><th>Transport</th></tr>
<tr><td rowspan="2">SAFETY</td><td colspan="4">Implement learning from validation of safety in renewable and decarbonised methane and blended/100% hydrogen trials by updating risk assessments and safety cases</td></tr>
<tr><td></td><td colspan="2">Provide network support to the development of safe 100% hydrogen operations for industrial and power generator sectors</td><td></td></tr>
<tr><td rowspan="8">SECURITY OF SUPPLY</td><td colspan="4">Implement learning from trials and develop mature network and system operations for roll out</td></tr>
<tr><td></td><td colspan="2">Develop deblending or other options for gas engine and gas turbine users not ready for H_2, including considering cost-effectiveness</td><td></td></tr>
<tr><td colspan="4">Develop cross-cutting power/H_2 and renewable and decarbonised methane/H_2 concepts</td></tr>
<tr><td>Engage with hydrogen production and storage developers for roll out at new build developments</td><td></td><td></td><td></td></tr>
<tr><td colspan="4">Develop detailed conversion plans for pilot to ensure security of supply of natural gas and hydrogen during conversion</td></tr>
<tr><td colspan="4">Deliver network investment required</td></tr>
<tr><td colspan="4">Engage with green gas producers to ensure sufficient renewable and decarbonised hydrogen and methane production and storage facilities (including CCS for blue H_2) for pilots and roll out</td></tr>
<tr><td colspan="4">Develop options for wider hydrogen conversion, including joint planning with renewable and decarbonised methane</td></tr>
<tr><td rowspan="9">SUPPLY CHAIN</td><td colspan="4">Continue training workforce during roll out</td></tr>
<tr><td>Extend training facilities to cover 100% H_2 in new property developments (objective 2)</td><td></td><td></td><td></td></tr>
<tr><td colspan="3">Continue engagement with manufacturers and suppliers of hydrogen equipment such as electrolysers & valves etc for roll out of 10% hydrogen blend</td><td></td></tr>
<tr><td colspan="4">Continue development and improvement of blending facility for hydrogen injection point</td></tr>
<tr><td colspan="3">Develop Type B appliances conversion kits for roll out</td><td></td></tr>
<tr><td colspan="4">Engage with supply chain to encourage scalable production line capability for H_2 compatible Type A appliances and components, including import option</td></tr>
<tr><td colspan="4">Identify manufacturing capability for equipment needed for conversion process such as sectorisation valves, purging</td></tr>
<tr><td colspan="4">Seek diversity and competition in supply chain provision</td></tr>
<tr><td colspan="4">Develop training facilities for converting natural gas networks to 100% hydrogen</td></tr>
</table>

Table 4-10 2026-2030 activities for each end-use sector

4.6 Actions required for transmission pipelines

The tables in the previous section cover network actions required for the distribution networks and transmission pipelines and then the actions required specifically for the transmission pipelines for each objective. The table below provides a consolidated list of all the actions that are required for transmission pipelines specifically across all the objectives.

	2021-2025	2026-2030	2031-2040	2041-2050
Transmission pipeline activities for objectives 1, 2 and 3 (renewable and decarbonised methane and hydrogen)				
CUSTOMER FOCUS	• Public and directly connected customer engagement, including distribution networks • Engage with large-scale gas engine and gas turbine users to trial equipment • Custody transfer measurement systems • Consumers able to buy green gas certificates for renewable and decarbonised methane and hydrogen	• Public and directly connected customer engagement, including distribution networks	• Public and directly connected customer engagement, including distribution networks	• Public and directly connected customer engagement, including distribution networks
SAFETY	• Update current methane gas quality specification standard AS 4564 to consider additional constituent components found in some renewable and decarbonised methane • 10% H_2 gas quality specification • 100% H_2 gas quality specification • Develop safe envelope of operation for hydrogen grid entry including mixing, control systems, backup storage etc • Hydrogen/gas detection equipment • Gasfitter and network training for 10% H_2 blend and 100% H_2 at trial production facility • Develop safety case for 10% H_2 blend and 100% H_2 • Offline trials of hydrogen blends and 100% hydrogen in transmission pipelines • Define safe upper limit for hydrogen blends in transmission pipelines, with reference to the AS 2885 standard • Liaison with emergency responders to outline the differences in properties between methane and hydrogen.	• Implement learning from validation of safety in trials by updating risk assessments and safety cases • Develop safe operations for industrial and power generator sectors	• Implement learning from validation of safety in trials by updating safety cases	

	2021-2025	2026-2030	2031-2040	2041-2050
Transmission pipeline activities for objectives 1, 2 and 3 (renewable and decarbonised methane and hydrogen)				
SECURITY OF SUPPLY	• Strategy for renewable and decarbonised methane supply, daily and seasonal storage, and natural gas backup • Strategy for renewable and decarbonised hydrogen production, daily and seasonal storage and natural gas backup • Network modelling, including capacity (given hydrogen's lower volumetric energy density), storage (linepack and seasonal), the need to maintain the resilience of the existing natural gas network, and the interaction with distribution network injection • Network entry • System operator and network management • Engage with green gas production and storage developers for roll out	• Engage with green gas production and storage developers for roll out • Implement learning from trials and develop mature network and system operations for roll out • Develop deblending or other options for gas engine and gas turbine users not ready for H_2 • Develop cross-cutting power/H_2 and renewable and decarbonised methane/H_2 concepts • Engage with producers to ensure sufficient hydrogen production and storage facilities (including CCS for blue H_2) for roll out. This includes linepack, large-scale hydrogen storage to meet seasonal demand, and the sector coupling of green hydrogen and the electricity market	• Joint roll-out of renewable and decarbonised methane and hydrogen • Ramp up hydrogen production and storage (including CCS for blue H_2) facilities	• Joint roll-out of renewable and decarbonised methane and hydrogen • Address any shortcomings that are apparent in the mature and sustainable commercial market
SUPPLY CHAIN	• Develop training facilities and material for the workforce to raise awareness of production sites, potential contaminants, and monitoring/audit gas entry measurement systems • Engage with manufacturers and suppliers of hydrogen pipeline equipment such as valves, measurement systems etc. • Develop blending facility for injection of 10% hydrogen • Business case for blending renewable and decarbonised methane and hydrogen and 100% hydrogen conversion	• Maintain and roll out training materials • Seek diversity and competition in supply chain provision • Continue engagement with manufacturers and suppliers of hydrogen pipeline equipment such as valves etc for roll out of 10% hydrogen blend • Continue development and improvement of blending facility for hydrogen injection point	• Engage with supply chain to encourage scalable production line capability for H_2 ready components	

Table 4-11 Transmission pipeline actions

4.7 Key Actions Required by Outside Organisations

Similar to the activities to be undertaken by gas networks and pipelines, the majority of actions required by outside organisations are needed in the first five years to 2025. Activities required by outside organisations span the foundational regulatory changes required to enable renewable and decarbonised hydrogen and methane industries, development of the renewable energy economy, and adjacent technical development of both end user and renewable and decarbonised gas production industries.

These actions are essential to prepare for, and enable, transition – for renewable and decarbonised methane, hydrogen blending and trials, and planning of full conversion. Carrying out key actions by 2025 is essential to being able to meet the 2030 blending and 100% hydrogen trials objectives, and from this perspective, the earlier that activities can be completed in a robust manner, the better.

4.7.1 Regulatory Changes

Removing regulatory roadblocks formed through historic regulation which didn't consider renewable gases, and setting in place regulatory frameworks within which a renewable gas economy can develop, will be key to forming a foundation from which renewable and decarbonised hydrogen and methane industries can grow. Harmonisation of technical, environmental and economic regulation across the whole of Australia would streamline and simplify the decarbonisation plan. Regulatory measures to secure a robust domestic renewable gas market alongside renewable gas exports will also be necessary to secure domestic supply.

For renewable and decarbonised methane and hydrogen, the following regulatory changes would be required, the vast majority of which are needed in the next five years.

Regulatory changes	2021-2025	2026-2030
TECHNICAL REGULATION	• Update gas quality regulations for renewable and decarbonised methane and hydrogen blend – clarifications for blended gases should not limit the current level of flexibility within the gas specification • Standardise natural gas terminology – for example, biomethane has been classified variously as "naturally occurring" and/or a "synthetic" gas • Harmonise licencing of gas fitters • Harmonise regulations on entry points in distribution networks and transmission pipelines • Agree billing methodology for blended networks • Update regulations determining access to customer properties required for 100% hydrogen conversion • Harmonise certification of gas equipment and appliances • Allow injection directly into distribution networks in states where there are currently regulatory barriers to this	
ENVIRONMENTAL REGULATION	• Develop environmental management and land use regulations for renewable and decarbonised methane and hydrogen, including considering, for example, water and bio feedstocks	

Regulatory changes	2021-2025	2026-2030
	• National Greenhouse Energy Reporting (NGER) Scheme should also recognise renewable and decarbonised gases in energy and emissions reporting frameworks	
ECONOMIC REGULATION	• Amend economic regulation to account for renewable and decarbonised gases. • Update the National Gas Law to allow renewable and decarbonised gas blends to be recognised	• Potential incentivisation regulation dependant on rate of uptake • Potential reservation policies when export markets develop to ensure that domestic use is prioritised when supply is tight
REGULATORY HARMONISATION	• Ideally, aim for harmonisation of green gas regulations across states and territories – regulator cooperation within Australia has commenced and it would be preferable to continue on this path	
ADDITIONAL TECHNICAL REGULATION FOR 100% HYDROGEN NETWORKS	• Develop specification of 100% hydrogen • Policy decision on new 100% H2 networks • Policy decision on mandating of hydrogen-ready appliances	• Policy decision on 100% H2 conversion (dependent on outcome of hydrogen objective 2)

Table 4-12 Regulatory changes

4.7.2 Market Development

With foundation regulation in place, a renewable and decarbonised gas market will be key to enabling the development of green gas uptake through gas networks and pipelines. Progressing to a renewable and decarbonised gas market where customer contracts can form the basis for project (CAPEX) and long-term operational (OPEX) financing is key to market growth. This should be underpinned by a renewable gas target, similar to the existing renewable energy target.

While early years will require some support for asset financing, much of the economic development can be achieved by enabling customers to connect with green gas suppliers through gas networks and infrastructure – there is already a growing number of organisations who would like to purchase green gas in the same way as they purchase renewable electricity PPAs. Additional market development could be supported by incentives in order to achieve jurisdictional emissions reduction goals.

Market development	2021-2025	2026-2030
MARKET ACCESS	Enabling renewable gas demand to access supply through transparent and flexible markets – similar to renewable electricity PPAs – is a key foundation upon which a renewable gas economy can be created. Market Access development activities include the following development focuses:	

Market development	2021-2025	2026-2030
	• Green Gas Certification (GGC) • Green Gas Sales Agreement (GSA) standard (GJ + GGC bundles) • Green Gas Trading within Wholesale Markets (Declared Wholesale Gas Market (DWGM), Short Term Trading Market (STTM), Gas Supply Hubs (GSHs); GJ + GGC bundles) • Commercial & Retail Green Gas Opt-In (see Green Tick for electricity)	
EARLY ASSET FINANCING	Early market supply can be seeded through existing subsidised financing frameworks. Access to lower risk financing will be key to enabling first supply into potential renewable gas markets, after which market forces can take over. Early Asset Financing development activities include the following development focuses: • ARENA Project Funding • Clean Energy Finance Corporation (CEFC) Equity and Debt Access • Venture Capital Marketplace Development	
RENEWABLE GAS TARGET	Implementing a target for renewable and decarbonised gas, similar to the existing renewable energy target, would help to underpin investment in renewable and decarbonised methane and hydrogen and support the market creation activities below.	
MARKET INCENTIVES	Green gas certification schemes are required to provide customers with confidence that they are purchasing a green product. Putting in place financial incentives which enable customers to purchase renewable gas will support market development in line with emissions reduction targets. Market incentive development activities include the following development focuses: • Tax incentives for purchasers of green gas • Federal/State fund purchase of customer owned certificates • Certificate market creation through Australian Carbon Credit Units (ACCU) to certificate equivocation • Eligible methods for funding support through the Emissions Reduction Fund • Retail price incentives	

Table 4-13 Market developments

4.7.3 Production and End User Technical Development

Alongside the development pathways to be undertaken by gas networks and pipelines detailed in Section 4.2 through 4.5, successful gas infrastructure decarbonisation requires further technical development of end use and production of renewable and decarbonised hydrogen and methane.

4.7.3.1 End user/ appliance manufacturers

Type A appliances

Appliance manufacturers need to develop hydrogen and hydrogen-ready appliances at scale, suitable for the Australian context.

Type B appliances

Because Type B appliances tend to be bespoke in nature, and may also be affected by 10% hydrogen blends, the steps are not identical to those for Type A.

4.7.3.2 Future fuels production

Given that the majority of renewable and decarbonised gas will be produced by organisations outside of networks, the key requirement here is to ensure that end-usage in Australia, and the ability of networks to transport the gases from production to consumption, is fully taken into account.

	2021-2025	2026-2030
Production and end user technical development		
END USER/ APPLIANCE MANUFACTURERS		
TYPE A APPLIANCES	• Development of hydrogen appliance standard • Appliance development, including the manufacture of prototypes and downstream fittings and parts • Testing of appliances for safety and performance • Certification of appliances at a state/territory level (ideally with national consistency) • Engagement with consumers to demonstrate efficacy of the appliances • Training of workforce to install and service	• Manufacture/import at scale
TYPE B APPLIANCES	• Development of hydrogen appliance standard • Determine approach to converting existing Type B appliances • Determine suitability of different categories of Type B appliance for 10% hydrogen blending • Develop conversion kits for both 10% blending and 100% hydrogen, to include modifications to burner control systems • Develop new 100% hydrogen appliances, especially those categories that are less easily converted. • Testing of appliances for safety and performance • Engagement with industry to demonstrate efficacy of the appliances • Training of workforce to install and service	• Manufacture/import at scale
FUTURE FUELS PRODUCTION		
PRODUCTION	• Ensure that projects designed for hydrogen export, and/or for local industrial use, are sized appropriately to supply a wider set of Australian customers • Ensure that sufficient daily and seasonal storage is planned for	

Table 4-14 Production and end user development

5 TENETS

A colour code is applied to differentiate how the tenet activities apply to each option as shown below.

Renewable and decarbonised methane

Hydrogen

Renewable and decarbonised methane and hydrogen

5.1 Customer Focus

The customer focus tenet is supporting consumers in residential, commercial, industrial, transport and power sectors to decarbonise the gas networks in Australia in a cost-effective and convenient way, keeping disruption to a minimum, ensuring accurate billing and taking interim steps to reduce emissions rapidly and early.

5.1.1 Billing and Flow Measurement

Billing and Heating Value Zones

Gas consumers are billed by the amount of energy consumed in MJ or in 'units' in Western Australia for example, where 1 unit = 1 kWh. Gas meters measure the volume of gas consumed, this is multiplied by the flow-weighted heating value (energy in a measured volume at reference conditions of 101.325 kPa and 15 °C) and a pressure correction factor in order to calculate energy consumption. The heating value is determined by gas chromatographs located at distribution receipt points and is flow-weighted based on the 'heating value zone'. The pressure correction factor is dependent on the location and environmental conditions.

If gases with lower energy content (i.e. renewable and decarbonised methane or hydrogen blends) are injected into the network alongside gases with a higher heating value, then the flow-weighted heating value zones may need to be revised to prevent unfair billing arrangements. This has been assessed in the Future Billing Methodology project in the UK[30]. Figure 19 below from the Future Billing project shows how a heating value zone can be impacted by the introduction of another source of low heating value gas such as biomethane or hydrogen blend. As an example, to ensure that customers receiving gas from entry point C are not disadvantaged, a new heating value zone will need to be created. In networks with high connectivity, the size of the heating value zone will vary with customer demand – at periods of high demand, the zone is small and at low demand the zone is much larger. This project is investigating fairer ways of billing to enable more low-carbon gases into the network without overcharging customers. One of the biggest hurdles in the UK has been updating the complex IT infrastructure that links consumer meters with suppliers, shippers and the gas transporters.

Billing arrangements for trials will also need to be reviewed by gas transporters and regulators. For 10% hydrogen blend, the heating value will decrease by about 2.5 MJ/m^3 but it will still fluctuate with any changes in the composition of the natural gas. The 100% hydrogen billing arrangements will depend on the gas quality specification for 100% hydrogen.

[30] Cadent Gas Future Billing Methodology Project https://futurebillingmethodology.co.uk/industry-information/

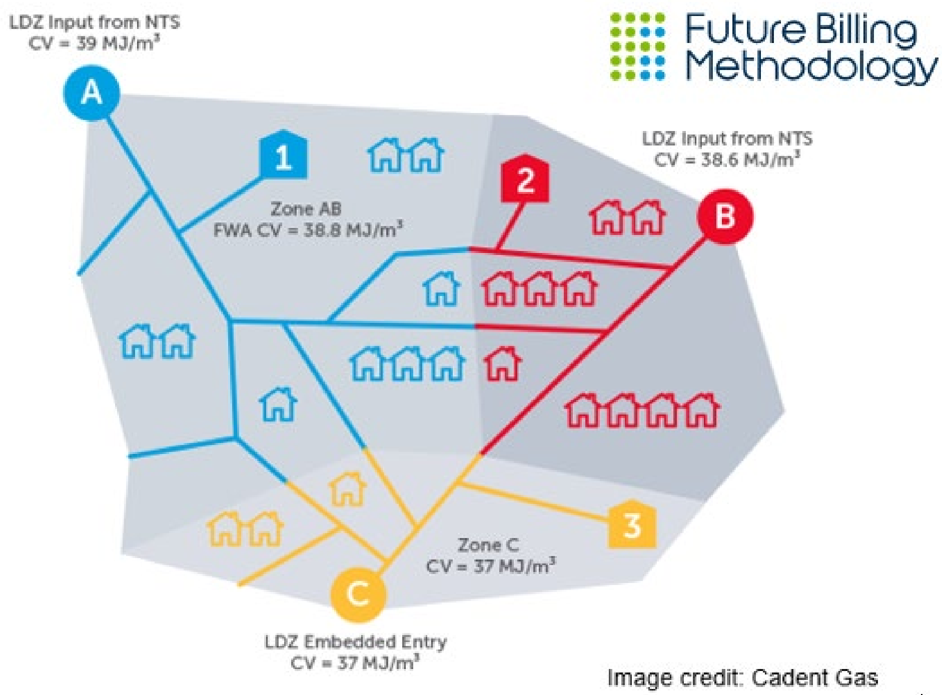

Figure 19 The Future Billing Methodology project is investigating fairer heating value zones in the UK. The term "LDZ" is the "Local Distribution Zone" and "NTS" is the National Transmission System.

Flow measurement technology

The influence of renewable gases on flow metering uncertainties will need to be considered, with meters being calibrated for a specified range of gas compositions. The European Joint Industry Project (JIP), HyReady[31] is tasked with setting guidelines for the introduction of hydrogen blends of up to 30%, including turbine and ultrasonic metering technologies. If the gas composition, particularly the concentration of hydrogen, is expected to vary greatly then this will have an impact on measurement uncertainty.

Gas chromatographs measure the gas composition throughout the network and are designed to accurately measure components at levels found in natural gas variations, including biomethane. The currently installed gas chromatographs are likely to use helium as a carrier gas which is unable to detect hydrogen, and therefore will be unable to accurately measure the hydrogen within both 10% blended and 100% hydrogen gas.

10% Hydrogen Flow Metering

Testing is required to ensure existing consumer flowmeters are able to handle 10% blend[32].

100% Hydrogen Flow Metering

The UK Hy4Heat[33] programme includes a work package to develop hydrogen smart meters. A safety risk assessment should be carried out to determine compatibility of UK (or other international) 100% hydrogen consumer meters for Australia and new meters developed if required.

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[31] DNV HyReady Joint Industry Project https://www.dnv.com/oilgas/joint-industry-projects/gas-value-chain/hydrogen-addition-to-natural-gas.html

[32] The Cadent HyDeploy project used standard meters with a 20% hydrogen blend and incorporated a billing correction so as not to disadvantage customers in the trial https://hydeploy.co.uk/

[33] BEIS Hy4Heat programme https://www.hy4heat.info/about-us

10% Hydrogen Gas Quality Measurement

Networks will need to ensure the gas analysis systems are compatible with a 10% blend of hydrogen.

100% Hydrogen Gas Quality Measurement

Networks will need to determine what impurities need to be measured for 100% hydrogen, in relation to a hydrogen gas quality specification.

5.1.2 Public Engagement

Detailed public opinion research is required to steer public engagement and gain community trust. It is important that a public engagement strategy encompasses the whole community, for example, local authorities and community groups should play a key role in communicating consistent advice.

Public engagement should start as early as possible and play a key part in any trial projects. Public knowledge of hydrogen as a fuel source is low and the outcome of trial projects can strongly influence public opinion.

Renewable and decarbonised methane public engagement

Renewable and decarbonised methane is similar enough to natural gas that public concerns are mainly cost and sustainability of supply. Biomethane in particular is a ready-to-go solution for reducing carbon emissions whilst Australia prepares for greater synthetic methane production and 100% hydrogen conversion of some networks.

Hydrogen public engagement

The benefits of hydrogen as a fuel source such as reduced carbon emissions, export opportunities and job creation should be highlighted; whilst concerns such as safety, cost, cost benefit versus electrification, land use, water consumption and short term increases in carbon emissions should be addressed. Public engagement on the distinction between green and blue hydrogen needs to be considered carefully as blue hydrogen may be seen as undesirable because carbon capture and storage is required in parallel.

For 100% hydrogen trials in new property developments, engagement with land and property developers and urban planners is also important.

Engagement with industrial and power generation sectors should follow on from trials, including with small-scale gas engine and gas turbine users to trial equipment. Engagement with electricity network operators is also needed to ensure that electricity requirements for hydrogen production align with ISP and respective jurisdictional electricity plans. Water utilities are also important stakeholders.

100% hydrogen demonstration facility

A demonstration house or facility to showcase hydrogen indoor and outdoor appliances, allowing consumer interaction, is a great way to engage with the public.

Engage with housing developers

Engagement with housing developers is crucial for the conversion and roll-out of hydrogen as well as trials and pilots. This is particularly important for the future of the gas networks – without engagement with housing developers, all future developers are likely to be all electric only. Housing developers need to understand how to incorporate hydrogen networks into their designs, that hydrogen appliances are available and acceptable to customers and that a range of energy options is a good thing for individual consumers and for Australia as a whole.

5.1.3 Trials & Pilots

Coordination of research and appliance development at a national level is required to reduce duplication in different states and provide a smoother pathway. To promote knowledge sharing, efforts should be coordinated with the

Future Fuels Cooperative Research Centre (CRC)[34], a collaboration of industry partners coordinating research, development and demonstration.

The evidence pathway, from desktop studies to roll out, is shown in Figure 20. The consumer hydrogen trials and pilots are steps from the middle of a longer process - the desk-top and off-line testing phases are critical for determining safety. Consumer trials and pilots can only be carried out if they are known to be safe, but they can be used to validate risk assessments which may have used conservative risk data.

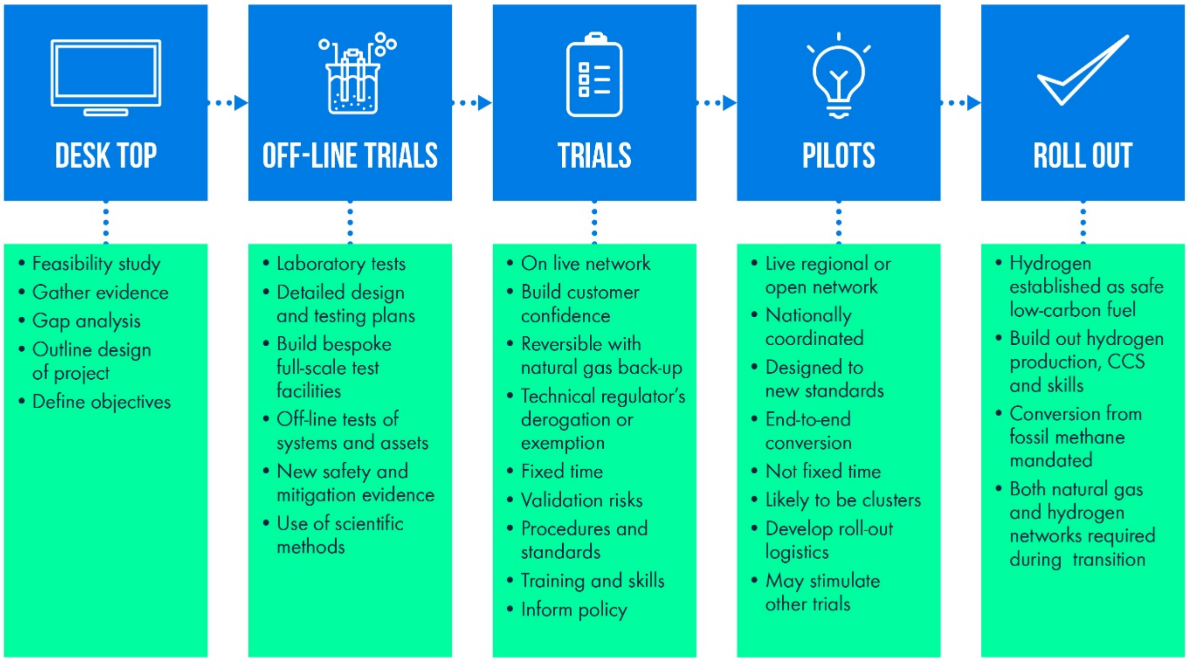

Figure 20 Evidence pathway for decarbonisation of networks using hydrogen

Trials in the following areas are required to inform future development and form the basis of hydrogen project safety risk assessments. Safety risk assessments for the trials themselves must be carried out and state regulatory approval given.

Trials and pilots should be coordinated across states and territories so that information can be shared and learning from one state can be applied in another.

10% hydrogen blending trials

10% hydrogen blending trials should be carried out by the gas distribution and transmission networks. This will test hydrogen production, hydrogen blend network operation and consumer acceptance of hydrogen with minimal disruption and without the replacement of domestic appliances. During any transition to 100% hydrogen, the use of hydrogen blends in both distribution and transmission may be necessary as part of the ramping up of hydrogen production during the conversion process.

100% hydrogen trials and pilots

100% hydrogen trials should be carried out by the gas distribution and transmission networks. A trial in a new network is the correct first step followed by the conversion of an existing network which is a much more complex process. This controlled approach will ensure that established scientific methods are used, that the results are representative of the gas networks in Australia and the outcomes are unambiguous.

[34] Future Fuels CRC https://www.futurefuelscrc.com/

100% hydrogen trials/pilots should be carried out in the network and also in new property developments. Within new property developments it would be envisaged that domestic and small commercial properties would be trialled first.

As a second phase, larger scale new developments could include industrial and commercial users, so engagement with small-scale gas engine and gas turbine users would follow.

5.1.4 Rollout Programmes

Following on from hydrogen trial projects, customer facing rollout programme strategies need to be devised. New developments may be relatively straightforward, but conversion programmes will need to consider security of supply during the transition – this will need meticulous and detailed planning. Prior to supplying hydrogen to the first house in the first street, there needs to be some major preparation work to ensure that:

- Customers that have converted to hydrogen continue to be supplied safely and securely with hydrogen with an enduring solution
- Customers that remain on natural gas also continue to be supplied safely and securely with natural gas until they are converted

Initially, gas networks may need to take responsibility for assets, operations and services that are currently outside their licences to operate. This could include, for example, hydrogen production and storage through to activities downstream of the meter including conversion of appliances in homes. Once hydrogen networks are well-established, these functions could be run on a more commercial basis. Issues that need to be resolved for a hydrogen conversion trial are:

- Hydrogen production and storage suitable for diurnal and seasonal demands
  - Interim production and storage may be required during the conversion process – including linepack, mobile/temporary storage and large-scale underground storage
  - Production will need to ramp up to match increasing demand as the conversion progresses and natural gas supply will need to be reduced
  - System balancing of the two networks
- Detailed street-by-street conversion strategy backed up by network models, asset information, repairs, sectorisation valves, emergency planning and customer engagement
- Compression of hydrogen
- Compatibility of pipelines and assets
- Hydrogen regulatory framework including gas specification, billing, planning applications, environmental considerations
- Development of the supply chain for electrolysers, methane reformers, consumer appliances
- Network installations such as pressure reduction, metering and measurement sites
- Training, competency and extra staff
- Project management and stakeholder management

Rollout programmes will need to be devised for the following:

100% hydrogen in new developments programme

The rollout programme will need to be designed according to well-established scientific methods. This means that the programme will need to control the number of variables under test to obtain meaningful results. As a first step to 100% hydrogen, a trial in a new development (objective 2) of the Plan is important as it avoids the complexity of converting existing assets – all pipework, network assets, services, customer appliances and the design of the properties will be suitable for 100% hydrogen and will not previously been used for natural gas.

100% hydrogen conversion programme

Following successful demonstration and customer acceptance in a new build development, objective 3 will explore a conversion trial. This will be a much more complex – the existing assets will have been designed, approved, maintained, repaired and used for natural gas. During conversion, there will be decreasing parts of the network supplied with natural gas and increasing parts of the network supplied with hydrogen. Customer appliances will need to be hydrogen ready, very detailed network modelling will be undertaken; hydrogen production and storage will need to be ramped up, including the input renewable electricity for green hydrogen; the natural gas supply will need to be backed off and so on. To ensure that customers are not without a gas supply for an unacceptable length of time, new pipework may need to be laid connecting the hydrogen supply to the conversion area.

Renewable and decarbonised methane rollout

Within the range of renewable and decarbonised methane options, biomethane is already being processed to comply with the current Australian gas quality specification, which means that biomethane can be rolled out both as a blend and as a replacement for natural gas. There is also an opportunity to roll out synthetic methane. The key risk is security of supply but natural gas, combined with storage of renewable and decarbonised methane, can be used as a back-up.

Transport hydrogen purification for fuel cells

Hydrogen supplied in a network to most gas consumers does not have to be very pure – the Hy4Heat[35] programme investigated the options for hydrogen production (blue and green), the cost of clean-up of blue hydrogen, contamination from the gas network and the needs of most gas consumers. Only fuel-cell users require very pure hydrogen so a programme of work will be required to purify the hydrogen, remove contaminants and the odorants and compress it for delivery to vehicle fuel tanks. A transport refuelling solution for 100% hydrogen trials would be helpful, demonstrating that networks can deliver hydrogen to transport refuelling stations.

Another option for transport users is on-site electrolysis at the refuelling site – however, this option requires green power and does not need a gas network connection.

5.1.5 Market Development

Green gas certificates

The actions required to develop a market for renewable and decarbonised gases are described in more detail in the Market Development tenet below, but for the benefit of consumers, it is important to make green gas certificates available for purchase in a similar way to green electricity certificates. This will help to meet demand for renewable and decarbonised gases that is already appearing and support further green gas production.

[35] Hy4Heat hydrogen purity standard report https://www.hy4heat.info/wp2#:~:text=It%20makes%20a%20recommendation%20for,the%20gas%20network%20and%20cost.&text=It%20recommends%20a%20hydrogen%20purity,for%20other%20likely%20trace%20components.

5.2 Safety

Conversion of the gas networks requires consideration of the gas quality limits, gas blending, suitability of pipeline materials, end user appliances and installer safety training. The National Gas Decarbonisation Plan's goal is to maintain the existing high safety standards for the existing natural gas network, whilst also allowing the introduction of hydrogen to the network.

Safety risk assessments in Australia (known as 'safety cases' in some states) work on the basis of reducing the risk so that it is as low as reasonably practicable (ALARP).

It will be important to work closely with the relevant emergency response services to ensure that they understand the changes to hazard distances and potential consequences related to the switch from methane to hydrogen.

5.2.1 Gas Quality

The National Gas Law and Australian Standard AS 4564:2020[36] does not specifically address blending renewable and decarbonised methane or hydrogen with natural gas. The current natural gas specification for transmission and distribution of a safe range of gases is summarised in Appendix B.

Renewable and decarbonised methane gas quality specification

Renewable and decarbonised methane is fundamentally very similar to natural gas. For biomethane specifically, there are the following exceptions:

(1) Biomethane could potentially contain higher levels of oxygen, which is increasingly more costly to remove. It may not be necessary to remove the oxygen from a safety perspective.

(2) Biomethane, in common with all renewable methane, the higher heating value (HHV) and Wobbe Index are likely to be lower than for natural gas

(3) Biomethane produced from landfill gas or wastewater feedstock may contain siloxanes, which can form solid deposits and damage the combustion systems and heat exchangers. The potential of siloxane formation needs checking.

Notes (1) and (2) are acceptable as long as they fall within the current limits for natural gas. For (3) if there is potential for siloxane formation, then complete removal during the clean-up process is likely to be the best solution as routine siloxanes analysis systems are currently not available. However, every biomethane plant must undergo a safety risk assessment which will ensure siloxane removal is a requirement before the gas is injected into the network. The current methane gas quality specification standard AS 4564 will require an update to consider additional constituent components found in some renewable and decarbonised methane.

The use of 'naturally occurring' / 'synthetic' natural gas terminology within regulations and standards needs to be clarified with regards to renewable and decarbonised methane, leading to the approval of renewable and decarbonised methane injection into gas networks.

Hydrogen gas quality specification

Hydrogen content is not explicitly specified so hydrogen will be controlled by the lower limits on Wobbe Index and relative density (quoted at reference conditions of 101.325 kPa and 15 °C). The standard AS 4564:2020 states the following limits:

- Wobbe Index range of 46 to 52 MJ/m^3
- Relative density "expected" to be in the range 0.55 to 0.70

[36] Australian Standard AS 4564:2020 General Purpose Natural Gas https://www.standards.org.au/

A summary of the differences in the properties of typical natural gas and 100% hydrogen is shown in Figure 21.

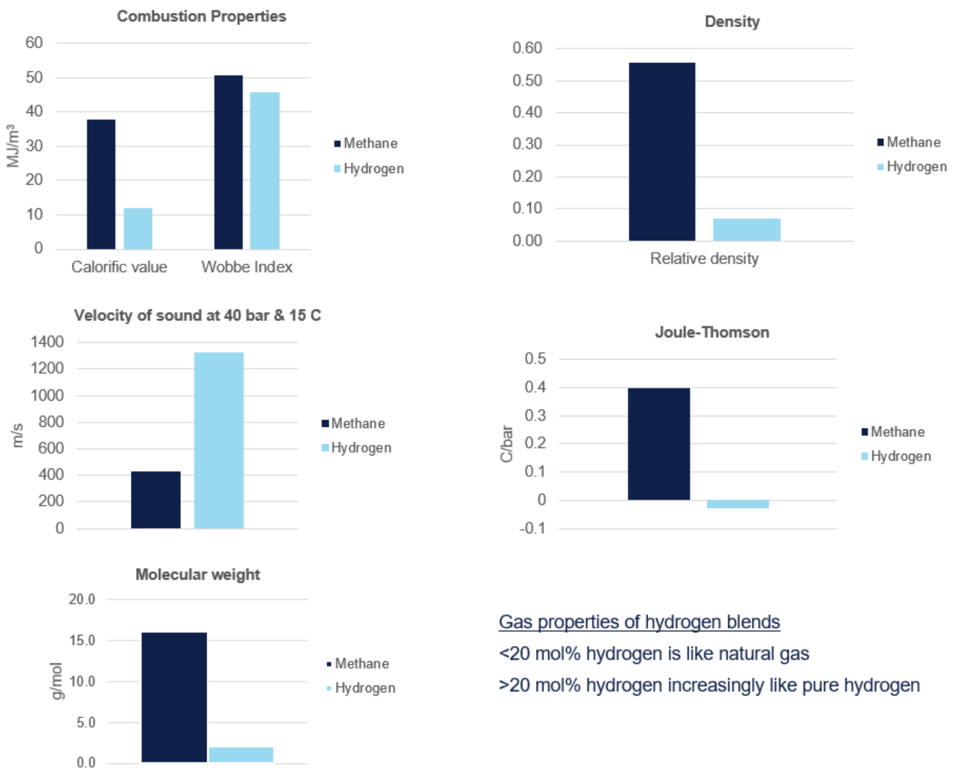

Figure 21 Summary of the differences in the properties of typical natural gas and 100% hydrogen

10% hydrogen blend gas quality specification

If hydrogen is added to natural gas, both the Wobbe Index and the relative density will decrease. If the starting natural gas mixture is already at the lower limits of either Wobbe Index or relative density, then the addition of any hydrogen will cause the gas to go out of specification. Biomethane tends to have a low Wobbe Index so could be problematic for hydrogen blending.

It is important to ensure a homogeneous blend and to avoid 'slugs' of hydrogen in the network. There will be little mixing of natural gas and a 'slug' of hydrogen, which could be detrimental to end user appliances if they are configured for natural gas blends.

Previous work on 20% blends has been carried out by Cadent Gas as part of the HyDeploy Project. A summary of the safety work was published in 2019[37].

100% hydrogen gas quality specification

To introduce 100% hydrogen into the network, a new gas quality specification for 100% hydrogen would be required. For example, the UK Hydrogen Purity Standard specifies 98% hydrogen[38] and this is compatible with 100% hydrogen domestic appliances. This would still allow, for example, a small amount of renewable and decarbonised methane to be blended with hydrogen in a '100% Hydrogen' network.

[37] HyDeploy: The UK's first hydrogen blending deployment. Tommy Isaac. Clean Energy, volume 3, issue 2, June 2019, pages 114-125 https://doi.org/10.1093/ce/zkz006

[38] Hy4Heat study funded by BEIS, a department of the UK Government https://www.hy4heat.info/wp2#:~:text=It%20makes%20a%20recommendation%20for,the%20gas%20network%20and%20cost.&text=It%20recommends%20a%20hydrogen%20purity,for%20other%20likely%20trace%20components.

5.2.2 Odorization and flame colourants

To detect odourless natural gas escapes, odorant is added, usually at the city gates, and is required by Australian Law to be added before entering the distribution networks. Odorization is not required for transmission networks. Gas odorant typically consists of 70% tetrahydrothiophene (THT) and 30% tertiary butyl mercaptan (TBM)[39].

Renewable and decarbonised methane odorization

A risk-based approach should identify whether renewable and decarbonised methane should be treated to remove any components that could mask the odorant added when the renewable and decarbonised methane enters the distribution network. Standard natural gas odorants should be suitable and used so that the public can continue to identify gas escapes accurately.

Hydrogen Odorization

Hydrogen is similarly an odourless gas. Previous work[40],[41] on a range of odorants for 100% hydrogen networks has concluded that existing odorants are effective – this needs to be confirmed by Australian network operators for their systems and odorant types. The H100 Fife[42] trial will be using natural gas odorants in Scotland on a 100% hydrogen new network – this project begins in 2021. For hydrogen blends up to 20%, a trial in the UK successfully continued to use existing natural gas odorization techniques.[43] The impact of odorant intensity due to the locations of hydrogen entry points into a gas network needs to be considered.

Hydrogen Flame Colourant

Pure hydrogen flames produce light in the ultraviolet range which makes them more difficult to see. The addition of colourants to improve the flame visibility should be considered.

5.2.3 Hydrogen Appliances

The introduction of hydrogen will impact on gas properties. The following properties need to be considered with regards to safety and their effect on the end users, see Appendix C for further details on the impact of hydrogen on gas properties.

- **Wobbe Index (WI):** Where the WI of the 'original' natural gas is close to the lower limit, the addition of 10% hydrogen could lead to poor/dangerous combustion of burners in appliances. Burners and appliances with natural gas burners will not be suitable for pure hydrogen.
- **Flame Speed Factor:** The addition of hydrogen increases the flame speed. Addition of 10% hydrogen may impact flame stability. During a depressurisation event, pure hydrogen could result in flash back.
- **Flammability Limit:** The addition of hydrogen increases the flammability range. The addition of hydrogen will impact on hazardous area calculations and increase the size of hazardous area zoning.
- **Flame Emissivity:** At 10% hydrogen, the flame colour will be similar to natural gas. Pure hydrogen flames produce light in the ultraviolet range which makes them more difficult to see. This also reduce the flame's ability to transfer heat in industrial processes which may result in a redesign of those processes.

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39 AEMO, Gas Quality Guidelines, September 2017.

40 Odorants for 100% hydrogen networks https://www.sgn.co.uk/about-us/future-of-gas/hydrogen/h100-nia/hydrogen-odorant-and-gas-detection

41 Energy Networks Australia Decarbonising Australia's Network Dec **2017** https://www.energynetworks.com.au/resources/reports/decarbonising-australias-gas-distribution-networks-energy-networks-australia-apga-gamaa/

42 H100 Fife project https://www.sgn.co.uk/H100Fife

43 HyDeploy trial - odorants for a 20% hydrogen blend https://hydeploy.co.uk/faqs/hydrogen-invisible-not-smell-will-know-leak/

- **Minimum ignition energy and auto ignition temperature:** For a 10% hydrogen blend, the ignition limits are similar to natural gas. For pure hydrogen the ignition limits are significantly lower than 100% methane. Pure hydrogen is suspectable to spontaneous ignition when released into the air at low pressure.

Type A hydrogen appliances

Domestic and light commercial appliances are classed as Type A appliances (e.g. boilers, cookers). The impact of hydrogen on Type A appliances has been the subject of a number of ongoing studies, suggesting no design changes required for 10% hydrogen blends. Changes to appliances will be required for 100% hydrogen and the UK Hy4Heat programme of work has reported on options for enhancing flame visibility (including the addition of flame colorant where necessary) and hydrogen-ready domestic appliances[44].

As set out in more detail in Section 4.7, appliance manufacturers need to develop hydrogen and hydrogen-ready appliances at scale, suitable for the Australian context. This includes:

- **Type A appliances:** Prototype appliance and fittings/parts development, testing for safety, certification, consumer engagement, workforce training and manufacture/import at scale.

- **Type B appliances:** Survey existing appliance for suitability for hydrogen blends, develop conversion kits, develop new 100% hydrogen appliances, testing for safety, industry engagement, workforce training and manufacture/import at scale.

Type B hydrogen appliances

Type B appliances largely refer to heavy commercial and industrial appliances i.e. non-standard installations. Due to the more bespoke nature of type B appliances, case by case safety risk assessments will be required.

Again, the Hy4Heat programme has two work packages investigating the range of natural gas commercial and industrial appliances in the UK and how these could be converted to hydrogen. A similar activity for Australia is required as many of these systems are likely to be bespoke.

Purification for fuel cells

Hydrogen fuel cells are highly sensitive to impurities. Where hydrogen is to be used as a transport fuel, purification may be required if the gas has been transported in a gas network - this includes the removal of any odorant as sulphur containing compounds poison fuel cells.

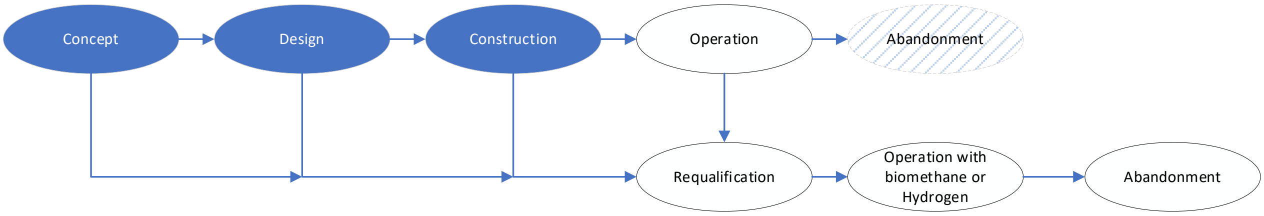
Pipelines

Renewable and decarbonised methane is very similar to natural gas as it is mainly methane and pipeline materials that are compatible with natural gas will also be compatible with renewable and decarbonised methane. For biomethane specifically, biomethane meeting the oxygen limits specified in AS 4564:2020 could be introduced into transmission systems without adverse effects on pipeline integrity – more details on using pipelines for biomethane can be found in Appendix D.

However, demonstration of the compatibility of pipelines with hydrogen is an important issue both for 10% hydrogen blends and 100% hydrogen. Any repurposed pipelines would also need to be in the correct geographical location to connect renewable energy zones to demand centres.

The repurposing of a natural gas transmission pipeline for an alternative fluid can be accomplished by a structured approach whose focus is maintaining pipeline integrity. This uses data from the existing pipeline (concept, design, construction, and operation) to requalify the pipeline for alternative fluids transportation. This process is shown below.

[44] BEIS Hy4Heat programme https://www.hy4heat.info/about-us



Hydrogen exposure can potentially cause degradation of the mechanical properties of iron and steel pipes and other components such as valves, gaskets, joints, fittings, and instrumentation.

The materials used in the transmission networks are chiefly conventional line pipe steels specified to the US API 5L standard with grades such as B, X-42, X-46, X-52, X-60, X-65 and X-70 (the nomenclature is X followed by Specified Minimum Yield Strength (SMYS) in ksi).

Safety risk assessments are required for the impact of hydrogen on consequence area assessment, pipeline materials and components (as per the FutureGrid and the H21 projects in the UK).

Requalification for hydrogen service is complex as AS2885 and AS 4564 do not specifically provide guidance for design or gas quality aspects of hydrogen pipelines.

The only hydrogen pipeline design standard currently available is ASME B31.12:2019 "Hydrogen Piping and Pipelines" and this has become the basis for requalifying natural gas pipelines for hydrogen service. B31.12 is applicable to all pipelines transporting ≥10% hydrogen, lower levels may continue to use natural gas design codes such as AS2885.1. Thus, both the 10% hydrogen and 100% hydrogen scenarios would use B31.12 as the controlling design code. This should take into consideration key developments such as:

- Work being done on Australian Standards and guidelines including the repurposing of AS2885 designed pipelines; and
- International collaborative efforts to conduct full-scale tests to enhance the understanding of susceptible micro-structures.

Many design aspects in B31.12 are similar to the corresponding natural gas code B31.8. However, the code has a more conservative approach to required wall thickness and consequently MAOP to address hydrogen degradation of pipeline steels. Two degradation modes are significant:

- Reduction in fracture toughness (FT)
- Accelerated fatigue crack growth rates (FCGR)

The B31.12 code has two options for determining wall thickness based on fracture control considerations (applicable if hoop stress is >40% SMYS), A (Prescriptive design method) and B (Performance based design method). Option B requires the pipe and welds to be qualified by testing for resistance to fracture in hydrogen gas. Both options use a modified design pressure formula (Formula 1) with an extra materials performance factor based on steel yield strength as shown in Table 1. Option A and Option B have separate design factor tables and in general F is lower for option A than option B. For example, for location class 1, option A has F of 0.5 and option B an F of 0.72.

$$P = \frac{2St}{D} FETH_f$$

Where:

- P is design pressure
- D is nominal outside diameter

- E is longitudinal joint factor
- F is design factor
- H_f is material performance factor
- S is Specified Minimum Yield Strength
- T is temperature derating factor
- t is wall thickness

SMYS, ksi	System Design Pressure (bar)	
	≤69	138
≤52	1.0	1.0
≤60	0.874	0.874
≤70	0.776	0.776
≤80	0.694	0.694

Table 5-1 Pipeline materials Performance Factor H_f (excerpt from B31.12)

The consequence of this approach is that hydrogen pipelines constructed of lower yield strength steel (SMYS ≤52 ksi) can have wall thicknesses and MAOP similar to natural gas pipelines. However, pipelines using higher strength steels require higher wall thicknesses than the corresponding natural gas and the difference is enhanced when using the prescriptive design method. As higher wall thicknesses are needed for higher strength steels for an existing pipeline the MAOP may need to be reduced.

The use of ASME B31.12 as the controlling code has the following implications for conversion of the existing Australian transmission pipeline networks to hydrogen service.

- Pipelines with line pipe SMYS of ≤52 ksi are likely to be suitable for hydrogen service at their current MAOP and design pressure if an option B design method is used. The design pressure would decrease by approximately 30% if option A were chosen. An assessment will still be required to assure that other components such as valves are compliant with B31.12 and to comply with the requirements of AS 2885.3 for a change of fluid.
- Pipelines with SMYS of ≥60 ksi can still be suitable for hydrogen service but are likely to require a reduction in design pressure and consequently MAOP. The design pressure reduction is large if option A is used and thus option B would be favoured for these pipelines. This will require testing of pipe and welds to demonstrate resistance to fracture. An assessment will also still be required to assure that other components such as valves are compliant with B31.12 and to comply with the requirements of AS 2885.3 for a change of fluid.

Fracture resistance testing would be onerous if required for each pipeline, so it is recommended that a joint programme is undertaken to create a database of test results for similar steel grades and manufacturing routes/vendors as testing proceeds. This should allow qualification of steels in the future without testing as the results can be taken from the industry database.

It is also recommended that AS 2885 is modified to address hydrogen service in Australian conditions and pipelining practices so that it may be used as the controlling design code.

Impact of hydrogen on pipeline materials & component materials

Hydrogen comparability and knowledge gaps should be assessed for all components in the network and for new-build networks. Hydrogen can cause several adverse effects on steel mechanical properties once atomic hydrogen enters the metallic lattice. It should be noted that molecular hydrogen has no effect on steels at normal pipeline operating temperatures.

For pipelines the credible degradation modes are a reduction in fracture toughness (FT) and increased fatigue crack growth rates (FCGR). Other hydrogen related degradation modes exist (e.g. hydrogen induced cracking HIC) but are not relevant to hydrogen pipelines as they are associated with the presence of H_2S or temperatures above 204 °C (High Temperature Hydrogen Attack, HTHA).

The changes in pipeline design procedures required for hydrogen service (at 10 and 100%) are discussed above.

Impact of 10% hydrogen on pipeline materials & component materials

The reduction in FT associated with hydrogen is related to the partial pressure of hydrogen present and thus a smaller effect would be expected in 10% hydrogen than 100% hydrogen. The increase in FCGR is found even at low partial pressures of hydrogen and thus will be a credible damage mode for 10% hydrogen.

Impact of 100% hydrogen on pipeline materials & component materials

Significant effects on FT and FCGR would be expected at transmission pressures for 100% hydrogen. As discussed in Appendix D it is likely that a design revalidation and test programme would be required to allow the transport of 100% hydrogen at similar pressures to natural gas.

Distribution mains replacement

Distribution networks are currently completing their own individual iron mains replacements plans to modern plastic pipes. This is expected to be completed in the mid-2020s.

Polyethylene (PE) piping and lower strength carbon steels are resistant to damage from hydrogen. Table 5-2 gives an indication of the types and amounts of different pipeline materials found in the Australian distribution networks.

Material	National Average
Nylon	26.33%
Polyethylene	41.42%
PVC	10.92%
Cast & Ductile Iron*	2.28%
Unprotected Steel	0.85%
Protected Steel	15.70%
Other	0%

*Cast iron is only found in low pressure applications (less than 1050 kPa)

Table 5-2 Australian National Network Materials[45]

Transmission pipelines

A pipeline database detailing the location and material of gas pipelines would be beneficial. An assessment of the impact of 10% hydrogen on transmission pipelines is required (as per the FutureGrid project in the UK). Replacement or revalidated transmission pipelines or operational mitigations such as the addition of small quantities of oxygen[46] may also be required if these are to be used to transport 100% hydrogen.

Hydrogen entry points

Pipelines enable the rest of the value chain to function; the location of hydrogen injection into the networks needs to be considered with regards to pipeline material as well as pipeline location with respect to hydrogen production, scenarios are as follows:

1. Use existing transmission pipelines that have been proven to be compatible with hydrogen
2. Build new dedicated hydrogen transmission pipelines
3. Inject straight into the distribution network
    a. Either via small, local production or
    b. Transport hydrogen by road, rail or ship (may use mobile injection skids)

Where gas is blended, any variability in the flow rate or intermittent injection of hydrogen needs to be mitigated via multiple injection points or storage.

[45] COAG Energy Council Working Group, Hydrogen in the Gas Distribution Networks, 2019.
[46] Feasibility of Hydrogen in the National Transmission System https://www.smarternetworks.org/project/nia_nggt0139/documents

Networks must develop a safe envelope of operation for hydrogen grid entry units including mixing, control systems, backup storage etc.

The need for parallel methane pipelines during conversion to 100% hydrogen should be considered – see Section 5.1.4.

Venting and purging

The existing natural gas pipework needs to be purged and replaced with hydrogen. There are two options that need to be assessed:

- Direct purging where hydrogen simply replaces natural gas
- Indirect purging in which an inert gas (for example, nitrogen) is used to purge the natural gas and then hydrogen is introduced

The H21 project[47] is investigating the effectiveness and safety of venting and purging in the UK – validation of this work or undertaking venting and purging tests in an Australian context is required.

Hydrogen safety equipment

Assessments should be carried out to determine the need for extra safety equipment such as excess flow valves and ventilation etc.

Industrial and power sector safe operations

Industrial and power generation sectors will need to work with Original Equipment Manufacturers as the presence of hydrogen may invalidate warranties and contracts. Combustion processes for gas turbines and gas engines are very sensitive to the presence of hydrogen and changes in gas quality resulting in decreasing operational efficiencies (commercial risks) and increasing emissions (regulatory risks).

Much of this is outside the remit of the gas networks but the networks need to work closely with this sector during the energy transition.

Gas detection equipment

The suitability of personal gas detection equipment for blends of 10% hydrogen and pure hydrogen needs to be assessed. Previous studies into gas detection for 100% hydrogen systems are available[48] but these need to be adapted to fit the Australian context.

Gas fitter training

Gas licensing currently varies between states and territories. All gas fitter training will need to cover hydrogen installation and appliance safety, this would ideally become a national standard to reduce barriers to hydrogen conversion.

During the energy transition and especially during trials and pilots, the gas networks may be responsible for hydrogen production and storage facilities. If necessary, gas network staff will need training to work on 100% hydrogen systems even for a 10% hydrogen blend; the hydrogen production systems upstream of the hydrogen entry point will have equipment, specifications and procedures for 100% hydrogen

[47] NGN H21 project https://www.h21.green/

[48] SGN H100 Project https://www.sgn.co.uk/about-us/future-of-gas/hydrogen/h100-nia/hydrogen-odorant-and-gas-detection

Hydrogen safety in the home

The safety of hydrogen in the home is likely to need to be as safe as natural gas in the home. An assessment will need to be undertaken to establish whether additional safety equipment or measures are required. For example:

- Installation of excess flow valves upstream of the consumer meter to shut off the hydrogen supply if a sudden rapid increase in flow is detected
- Increased ventilation measures may be required within properties
- Siting of domestic meters and appliances

The Hy4Heat programme has already reported on some of these measures and research is ongoing.

For new property developments, hydrogen safety would ideally be built into the design of the home, to avoid the need for retrofits.

5.2.4 Safety Risk Assessments

Safety Risk assessments are required for the following:

- 10% blend in natural gas appliances
- 100% hydrogen appliances
- 10% blend and 100% hydrogen in homes/commercial premises
- The impact of 10% blend and 100% hydrogen on distribution pipelines and associated infrastructure. Distribution networks are currently undergoing their own individual mains replacements plans to PE. Replacement of iron mains to PE must be completed for 100% hydrogen.
- The impact of 10% blend and 100% hydrogen on transmission pipelines and associated infrastructure (as per the FutureGrid project in the UK).

The safety risk assessments should be based on the established and approved methodologies for natural gas networks, production, storage and customer end use. They are likely to contain the sections/content such as that identified in Figure 22. Networks must implement learning from validation of safety in trials by updating safety case. Modifications for biomethane are likely to be minor, 10% hydrogen blend more extensive and most extensive for 100% hydrogen networks.

Figure 22 Topics likely to be covered in a safety risk assessment for a change of gas supply.

5.3 Security of Supply

The security of supply tenet is focused on maintaining the high security of supply standards that currently exist, with very few unplanned interruptions, especially for residential consumers – reconnecting large numbers of residential consumers following a gas outage can be very time consuming and has an associated risk if the gas networks allow them to purge their own pipework. Industrial consumers are important, but the risk is commercial as they will have more advanced safety and control systems. Security of supply includes physical network capacity, effective system operations, linkages to sufficient renewable and decarbonised gas production, storage facilities, sector coupling and market policies to facilitate the conversion process.

5.3.1 Network Modelling and Entry

Network modelling

To facilitate a variety of gas qualities being injected into the networks, consideration of more accurate gas energy modelling may be required for network operators. This has been assessed by the Real-Time Networks project in the UK[49] to better monitor gas quality at smaller network nodes. The project included meter logging of a sample of 600 residential gas consumers from a statistically representative range of demographics and property types. Meter loggers were also fitted to a statistically representative range of 600 industrial and commercial customers. The information has been used to understand gas distribution network operation for the full range of consumer demand behaviours, the impact of renewable technologies (for example heat pumps), varying weather conditions and varying gas quality. The project concept is shown in Figure 23 and the data flow is shown in Figure 24.

[49] SGN's Real-Time Networks Project https://sgn.co.uk/about-us/future-of-gas/hydrogen/real-time-networks

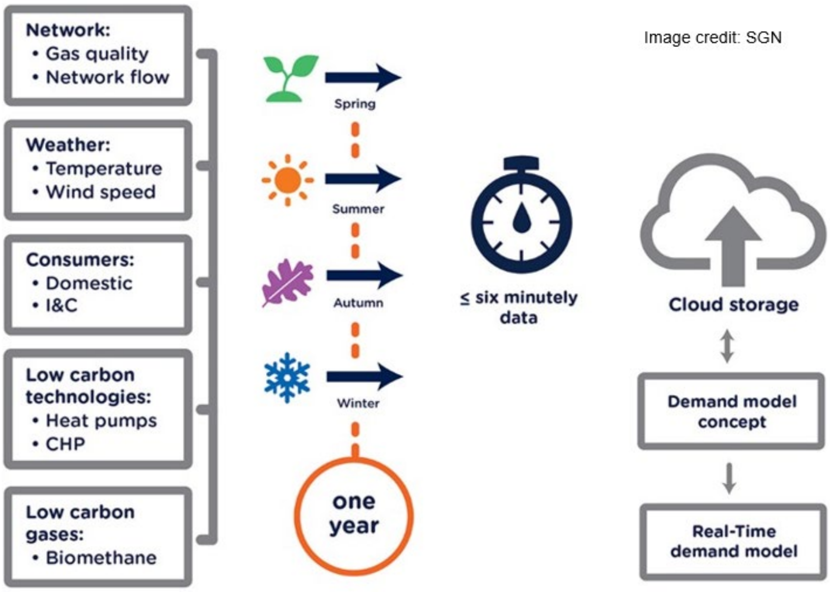


Figure 23 Concept for the SGN Real-Time Networks project

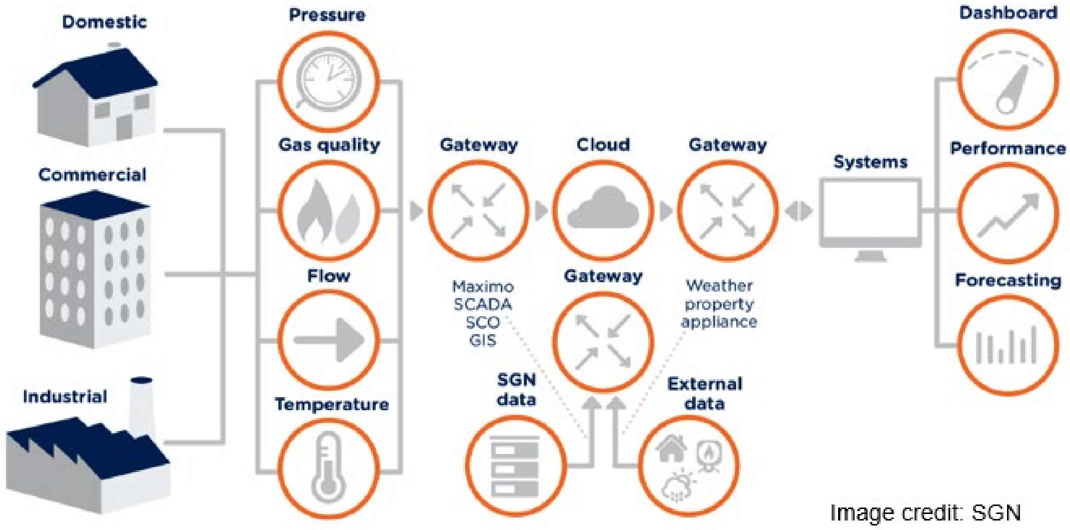


Figure 24 Data flow in the Real-Time Networks project.

Network entry

Network entry approval systems are currently configured for large flows into the transmission system. The processes for network entry for renewable and decarbonised methane and hydrogen connections needs to be standardised to speed up new connections, with the potential for a larger number of small injection points into the distribution system. Gas quality and the potential contaminants specific to the source of the renewable and decarbonised methane or hydrogen will need to be assessed on a risk basis. Network entry specifications would also benefit from standardisation of injection equipment, both permanent and mobile skids.

It is important to discuss the network modelling and network entry outputs with green gas production and storage developers, to help inform choice of the most suitable locations for production and injection into pipelines and networks.

5.3.2 Renewable and Decarbonised Methane Security of Supply

Renewable and decarbonised methane production

Sufficient renewable and decarbonised methane production capacity needs to be considered. Where renewable and decarbonised methane plants are unable to guarantee supply up to a satisfactory length of time for the gas network operators, there is potential for renewable and decarbonised methane and natural gas blending with natural gas back up.

The economic regulatory framework needs to be reviewed so that it can support renewable and decarbonised methane production, transportation and use.

Renewable and decarbonised methane storage

Sufficient renewable and decarbonised methane storage capacity is required to maintain security of supply, alternatively as mentioned above, there is potential for renewable and decarbonised methane and natural gas blending with natural gas back up.

5.3.3 Hydrogen Security of Supply

Impact of hydrogen on network capacity

Network capacity modelling for both distribution and transmission pipelines is required (including any new transmission pipelines being built). Hydrogen has a lower Higher Heating Value (HHV) than natural gas, meaning a larger volume of gas will be required to meet the same energy demand with both 10% blends and pure hydrogen. The addition of hydrogen will also decrease the relative density, increasing gas velocity and the pressure loss experienced.

Network capacity modelling also needs to consider the capacity required during transition to 10% hydrogen and conversion to pure hydrogen, i.e. maintaining the existing methane network.

Hydrogen system operator network management

System operators will need to consider how the transition to hydrogen will be managed. Guidelines are required on how demand will be met, how the system will be balanced, how the hydrogen supply market will operate and how to maintain pressure in the network. During the energy transition, the system operator will need to maintain the natural gas network throughout transition to 10% hydrogen and conversion to pure hydrogen.

The potential for a large number of small entry points throughout the network needs to be considered in terms of capacity as well as managing the composition of 10% hydrogen blends travelling through the network. For example, renewable power generators could switch to producing hydrogen from electrolysis when the electricity transmission network is constrained. Learning from hydrogen trials shall be implemented to develop a scalable method for system operations during hydrogen conversion.

Hydrogen market policies

In order to secure domestic supply of hydrogen and ensure access to competitive gas prices throughout Australia, an analysis of hydrogen reservation policies is needed.

The national gas market regulatory energy framework needs to be updated to include hydrogen, for example, providing a business model to pay hydrogen producers for hydrogen injected into the network. This may also be important for a hydrogen trial.

Any shortcomings that are apparent in the scalable and sustainable commercial market need to be addressed.

Hydrogen production

The regulatory framework for hydrogen production facilities[50] needs to be continued to be reviewed[51] and should be applied nationally – this includes economic, technical and environmental regulations. Hydrogen production facilities currently come under work health and safety legislation and may be additionally defined as a Major Hazard Facility depending on the production levels.

Renewable energy capacity and resilience needs to be considered for the production of green hydrogen via electrolysis.

10% blended hydrogen in networks would provide an early demand for hydrogen production, given that few changes are required, and the gas demand is already there. The potential for natural gas backup should be reviewed.

Hydrogen hubs can kick start hydrogen production capacity; having a number of hydrogen users together in one area minimises infrastructure costs, develops a skilled hydrogen workforce, and promotes innovation. The potential location for these hubs (e.g. existing industrial clusters, close to renewable energy generation) needs to be assessed state by state and regulatory support provided in order to streamline project approval.

Another option is to have distributed hydrogen production close to consumption.

Final Investment Decisions (FIDs) for hydrogen production projects will be needed. These projects will have other end-users outside of the networks – for example exports and industry directly connected to the hydrogen production – so it is important for networks to be engaged.

Hydrogen storage

Sufficient hydrogen storage capacity is required to maintain security of supply as hydrogen has about one third of the volumetric energy content of natural gas. Consideration should be given to the location of storage facilities with regards to injection points; at peak demand, storage capacity will be needed to for both 10% hydrogen blends and 100% hydrogen. An investigation into repurposing of natural gas storage is required, i.e. what impact does 10% blends and hydrogen have on the storage capacity as well as the storage assets.

For trials, it is important that hydrogen production and storage is considered together, with possible overcapacity built in, to maintain security of supply for the trial and avoid any damaging interruptions.

Hydrogen deblending and purification

Consideration should be given to deblending facilities for CNG engines and purification facilities for hydrogen fuel. Compressed Natural Gas (CNG) engines are very sensitive to the presence of hydrogen. Hydrogen deblending or a dedicated natural gas supply would be required for CNG engine supply. For the power generation sector, 10% hydrogen blend may be problematic and early engagement with users and manufacturers of gas turbines and gas engines would be recommended.

Transport infrastructure

The scaling up and location of hydrogen vehicle refuelling infrastructure needs to be considered. For example, hydrogen refuelling of large commercial vehicles and buses could be centred around hydrogen hubs.

Hydrogen conversion strategy

Bringing together the above actions, a 100% hydrogen conversion strategy needs to be developed. This will include identification of the parts of the network that will be converted, new transmission pipework, hydrogen production

[50] The Future Fuels CRC Research Programs and Project Overviews https://www.futurefuelscrc.com/wp-content/uploads/FFCRC-Research-Program-and-Project-Descriptions-September-2020.pdf

[51] The Australian Government is already reviewing economic regulations and the impact on different jurisdictions

and storage and the maintenance of natural gas during the conversion. This should be consistent with the joint planning of renewable and decarbonised hydrogen and methane roll out.

A conversion strategy should also take note of the dates for completion of the mains replacement programme, which is a necessary condition for use of 100% hydrogen in existing networks.

5.3.4 Cross-cutting

Electricity and hydrogen gas sectors

Electricity and hydrogen gas sector coupling will lead to better integration of renewable energy systems and improve security of supply through the following:

- Excess power produced by renewable energy generation can be turned into hydrogen via electrolysers to store energy or power transport and prevent curtailment.
- Stored hydrogen can be turned back into electricity to help meet peak electricity demand.

The electricity and gas sectors can share a common pathway to decarbonisation via sector coupling. The forthcoming AEMO 2022 Integrated System Plan is likely to consider hydrogen as an option – although mainly for industry and export purposes.

Electricity and gas price control periods are currently not synchronised, which inhibits joint electricity and gas network planning. It would be beneficial to align electricity and gas within the next price control periods.

We think it is prudent to plan for a mix of renewable and decarbonised methane and hydrogen conversion, and recommend a specific project to work with renewable and decarbonised methane and hydrogen producers (and the electricity grid operators) to determine areas that might be most suitable for each pathway. This project would also help to establish production capacity and volumes required for blending and full conversion roll out in different states and territories.

Renewable and decarbonised methane and hydrogen

Renewable and decarbonised methane and hydrogen can work together to achieve Australia's decarbonisation goals. Consider production location and capacity - it may be possible to have isolated renewable and decarbonised methane and hydrogen networks. Where a network can be supplied by 100% renewable and decarbonised methane, there is no need for the addition of 10% hydrogen blending.

5.4 Market Development

The market development tenet is focused on progressing to a renewable and decarbonised gas market where customer contracts can form the basis for project (CAPEX) and long-term operational (OPEX) financing, which is key to market growth.

Definitions

The broad definition of green hydrogen is hydrogen produced from renewable energy sources and blue hydrogen is where hydrogen is produced from fossil fuels and incorporates Carbon Capture and Storage (CCS). The definition of a 'green gas' with respect to hitting renewable targets and awarding funding needs to be clarified. Biomethane, hydrogen and synthetic gases can all be considered 'green gas' but care must be taken as to the origins of such gases, i.e. carbon emissions during production.

A common national standard for green gas, including carbon emission limits, is desirable. Standardisation nationally will benefit both internal trade and export.

International work can be drawn upon here. For example, the EU has a taxonomy on sustainable investment, which provides emission limits for hydrogen production – either directly for blue hydrogen or via the carbon intensity of the electricity generation for green hydrogen.[52] Similar emissions limits could be adopted in Australia, and the question of tightening emission limits over time is also relevant.

Certification

Standardising the definition of a green gas leads on to a certification system or register that verifies / guarantees the origins of a gas, for example, Europe's CertifHy scheme. The certification should verify energy source and lifecycle emission limits. The definition of lifecycle emissions and what this encompasses would need to be reviewed in the above "Definitions" step.

A national green gas certification system should also consider international standardisation in order to facilitate exports.

Market development

A national registry of green gas certificates could aid market development. The National Greenhouse Energy Reporting Scheme will need to be amended to allow green gas certificates and green electricity certificates to demonstrate emissions reduction. Power Purchase Agreements (PPA) could also benefit from a specific "green gas purchase agreements", utilising green gas certificates. Targets for a growing proportion of green gas in the mix can also be an important element in driving uptake.

The King Review recommended enhancing the Emissions Reduction Fund and a goal-oriented co-investment programme to bring down the cost of transformative technologies such as hydrogen. It also noted that a certification process is not yet available for biomethane.[53]

Early asset financing

Early market supply can be seeded through existing subsidised financing frameworks. Access to lower risk financing will be key to enabling first supply into potential renewable gas markets, after which market forces can take over.

Early Asset Financing development activities include the following development focuses:

- ARENA Project Funding
- CEFC Equity and Debt Access
- Venture Capital Marketplace Development

Market incentives

Putting in place financial incentives which enable customers to purchase renewable gas will support market development in line with emissions reduction targets. Market incentive development activities include the following development focuses:

- Tax incentives for purchasers of green gas
- Federal/State fund purchase of customer owned certificates
- Certificate market creation through Australian Carbon Credit Units (ACCU) to certificate equivocation
- Eligible methods for funding support through the Emissions Reduction fund
- Retail price incentives

[52] EU taxonomy for sustainable activities https://ec.europa.eu/info/business-economy-euro/banking-and-finance/sustainable-finance/eu-taxonomy-sustainable-activities_en

[53] Australian Government, Department of Industry, Science, Energy and Resources, Report of the Expert Panel examining additional sources of low cost abatement, 14 February 2020 https://www.industry.gov.au/data-and-publications/examining-additional-sources-of-low-cost-abatement-expert-panel-report

5.5 Supply Chain

The supply chain tenet is ensuring a skilled workforce is available to construct and convert the gas network on time, including end use equipment.

5.5.1 Training

Skilled workforce

A sufficiently skilled workforce is required to carry out 10% hydrogen trials, 100% hydrogen production sites for trials and 100% hydrogen conversion (retrofitting and new developments) including any remaining mains and equipment replacement.

Training programmes and facilities for hydrogen safety, including gas fitter licencing, need to be produced and ideally standardised nationally in order to prevent barriers to hydrogen conversion.

5.5.2 Equipment

Manufacturing hydrogen equipment

Appliance Manufacturing

Once a decision has been made to convert to 100% appliances, the mandating of hydrogen-ready appliances as soon as possible is essential. Hydrogen-ready appliances can start to be installed as existing natural gas appliances get to the end of their life; this will minimise disruption during any conversion programme as the change-over to hydrogen burners would take less than an hour. Any existing natural gas appliance are likely to need to be changed out completely which is more costly and disruptive.

Hydrogen appliance manufacturing capacity will need to be scaled up and is key to hydrogen conversion programmes. Certification of appliances may happen at a state/territory level currently, but national consistency for hydrogen and hydrogen-ready appliances would provide further support to meeting decarbonisation targets. This should also include downstream fittings and parts.

Type B appliances are likely bespoke; consideration should be given to producing hydrogen conversion kits for 100% hydrogen roll-out for type B appliances, including modifications to burner control systems. A survey of existing Type B appliances is needed to help determine the proportion of existing Type B appliances that are suitable for 10% hydrogen blending. New Type B appliances will also need to be developed, especially for those categories of appliance that are less easily converted.

Production and Maintenance Equipment Manufacturing

Engagement is required with manufactures and suppliers of hydrogen equipment such as electrolysers, valves, measurement systems, tools for service sectorisation valves, purging etc.

Blending Facility (Hydrogen Injection Point) Manufacturing

Blending Facility (Hydrogen Injection Point) manufacturing for injection of both 10% and 100% hydrogen needs to be considered.

Consumer Engagement

For both Type A and Type B appliances, engagement with consumers will be needed to demonstrate the efficacy of the appliances, following safety and performance testing.

Manufacturing Capacity

Manufacturing capacity for the above items needs to be at sufficient scale for roll-out of hydrogen. This could also include certifying imported appliances and other equipment for use in Australia, which may also have a beneficial impact on equipment prices. Diversity and competition in supply chain provision is desirable.

5.5.3 Business Case

Joint business case

A joint business case should be developed for renewable and decarbonised methane and hydrogen, complementing the joint planning described above, to demonstrate to outside organisations how renewable and decarbonised methane and hydrogen can be developed and substantial emissions reductions achieved cost-effectively. This will complement the market development actions needed by outside organisations.

6 REGULATORY CHANGES

Where possible, updates to Australian regulations and legislation should be considered at a national level to streamline and simplify the decarbonisation plan. Where regulations are harmonised nationally, there are economies of scale for procurement of assets and services and anti-competitive practises are prevented. The Western Australia network is isolated from the other gas regions, but standardisation should be considered.

Policy decisions for 100% hydrogen conversion of the networks should consider learning from trials and 100% hydrogen rollout in new developments. Learning from trials and pilots from overseas should also be an important input to Australian policy decisions.

A review identifying where changes may be required to existing Australian legislation (Acts, regulations, statutory policy and referenced standards) has been undertaken by Future Fuels CRC[54].

An overview of regulatory considerations is given in Table 6-1.

Regulatory Considerations	Customer Focus	Safety	Security of Supply	Market Development	Supply Chain
TECHNICAL REGULATION					
Blending: Update gas quality regulations for renewable and decarbonised methane and hydrogen blend – clarifications for blended gases should not limit the current level of flexibility within the gas specification.	✓	✓	✓	✓	
Terminology: The use of 'naturally occurring' / 'synthetic' natural gas terminology within regulations and standards needs to be clarified with regards to renewable and decarbonised methane, leading to the approval of renewable and decarbonised methane injection into gas networks.		✓	✓	✓	
Gas Fitter Licensing: Gas licensing varies between states and territories and all gasfitter training will need to cover hydrogen installation and appliance safety. Having a nationalised gasfitter training / licensing programme would reduce unnecessary barriers to the supply chain.		✓			✓
Entry Points in the Distribution Network: In certain states, there are barriers to injection directly into the distribution network. Regulations should be updated to allow injection into the distribution network; this will increase opportunities for renewable and decarbonised methane and hydrogen production and aid transport to the end user.			✓		
Customer Billing: A billing methodology for blended networks is required to ensure fair billing of gas consumers where the gas quality seen by the end users within a network may vary.	✓				

54 Future Fuels, CRC, RP2.2-01: Regulatory Mapping for Future Fuels, June 2020

Regulatory Considerations	Customer Focus	Safety	Security of Supply	Market Development	Supply Chain
Conversion Programme Access: Regulations determining access to customer properties required for 100% conversion programmes are required and must be location specific.	✓				
Gas Equipment Certification: Currently, each state and territory require gas equipment and appliances to be certified by their own technical regulator. In order to meet the Gas Vision objectives of 100% renewable gas by 2050, a national certification for hydrogen ready appliances is recommended.	✓	✓			
Entry Points in the Distribution Network: In certain states, there are barriers to injection directly into the distribution network. Regulations should be updated to allow injection into the distribution network; this will increase opportunities for renewable and decarbonised methane and hydrogen production and aid transport to the end user.			✓		
ENVIRONMENTAL REGULATION					
Environmental Management and Land Use: Environmental management and land use regulations need to address renewable and decarbonised methane and hydrogen production for gas injection into the network in order to streamline project approval processes.				✓	✓
National Greenhouse Energy Reporting Scheme: The National Greenhouse Energy Reporting (NGER) Scheme will need to be amended to allow green gas certificates and green electricity certificates to demonstrate emissions reduction.				✓	
ECONOMIC REGULATION					
Gas definition: Update the National Gas Law to allow renewable and decarbonised gas blends to be recognised.			✓	✓	✓
Green Gas Certification / Verification: A national green gas certification system should verify energy source and lifecycle emission limits. The definition of lifecycle emissions and what this encompasses would need to be reviewed. International standardisation would facilitate exports.				✓	
Economic Regulations to Develop Markets for Green Gases: Enabling renewable gas demand to access supply through transparent and flexible markets is a key foundation upon which a renewable gas economy can be created. Early market supply can be seeded through existing subsidised financing frameworks. Inclusion of renewable and decarbonised methane and hydrogen within the regulated asset base could also be considered in order to streamline connection of production facilities with the end user / industrial hubs				✓	
Potential Incentivisation Regulation Dependent on Rate of Uptake:				✓	

Regulatory Considerations	Customer Focus	Safety	Security of Supply	Market Development	Supply Chain
Putting in place financial incentives which enable customers to purchase renewable gas will support market development in line with emissions reduction targets.					
Potential Reservation Policies: Reservation policies for hydrogen may be needed as export markets develop to ensure that domestic use is prioritised when supply is tight.			✓		
REGULATORY HARMONISATION					
Harmonisation: Ideally, aim for harmonisation of green gas regulations across states and territories – regulator cooperation within Australia has commenced and it would be preferable to continue on this path	✓	✓	✓	✓	✓
100% HYDROGEN TECHNICAL REGULATION					
Develop Specification for 100% Hydrogen: A specification for 100% hydrogen is required; a national standard would aid a coordinated Australian conversion.	✓	✓	✓		
Policy Decision on new 100% Hydrogen Networks: A policy decision is required to allow new 100% hydrogen networks.	✓	✓	✓	✓	✓
Policy Decision on Mandating of Hydrogen Ready Appliances: Hydrogen conversion programmes must ensure that customers appliances are able to safely burn hydrogen, and hence a mandate to install hydrogen ready appliances is required.	✓		✓		✓
Policy Decision on 100% Hydrogen Conversion: A policy decision is required to allow conversion of existing networks to 100% hydrogen, informed by the trials of 100% hydrogen	✓	✓	✓	✓	✓

Table 6-1 Australian Regulatory Considerations

7 KEY RISKS

There are six key risk categories to the delivery of low-carbon gas networks in Australia and these are summarised in Figure 25.

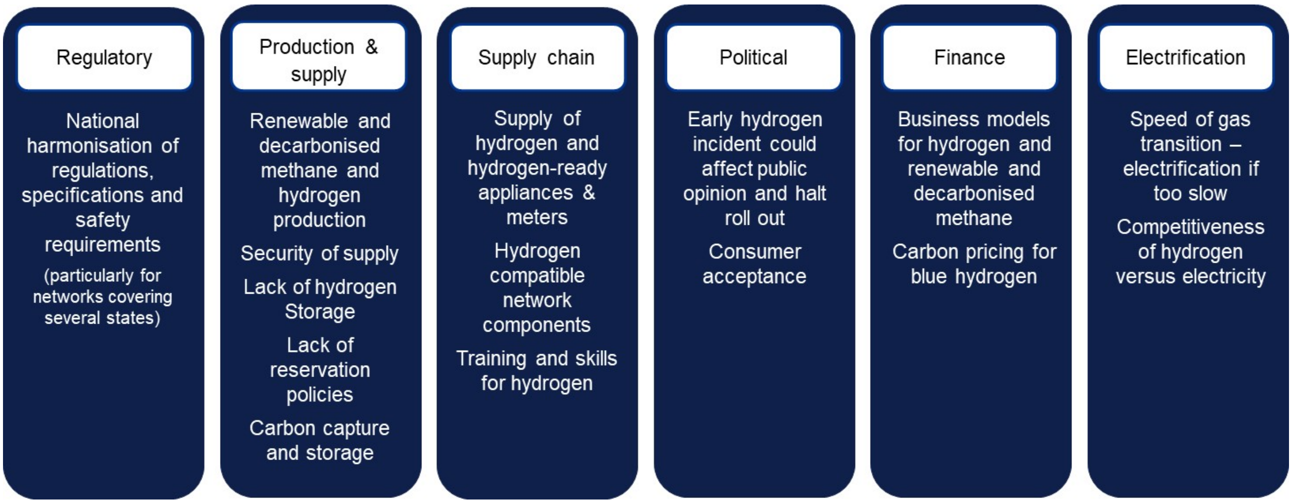


Figure 25 Six key risks for delivery of renewable and decarbonised gas networks in Australia

The current regulatory regime in Australia varies between states and territories. Continuation of this devolved approach could hinder the development and acceptance of a national plan for the gas networks – harmonisation of specifications, safety requirements, procedures and sharing of knowledge will enable a timely and cost-effective transition. There is a further risk that if there is too much delay in proving that renewable and decarbonised hydrogen and methane can replace natural gas, then electrification could become the preferred option by default.

The production and supply of renewable and decarbonised methane and hydrogen in sufficient quantities will be a key risk:

- Biomethane is traditionally produced in small quantities and the output flow rate is relatively flat as it is an organic process – this may not match peaks in demand. As production facilities may be remote from the gas networks, multiple smaller network entry points at lower pressure tiers may necessitate a different way of operating the system.
- Synthetic methane production is not limited by sustainable feedstock levels, but the energy requirements for production do need to be taken into account.
- Hydrogen production can be either blue or green. At first, blue hydrogen from the existing natural gas supply is likely to be scalable but it would need to be matched with carbon capture and storage facilities. Green hydrogen will require renewable electricity which is intermittent. The key risks for blue hydrogen are that the installation of the methane reforming plant at network entry points must be coupled with carbon capture and storage and the natural gas supply needs to be enduring. For green hydrogen, the key risks are the availability of renewable electricity, a good quality water supply and back-up storage to cover the intermittency of wind or solar power.
- As hydrogen has one third of the volumetric energy compared with natural gas, hydrogen storage will be critical to maintain security of supply.

The supply chain of equipment, appliances, and a qualified workforce will be critical. The conversion of the existing natural gas network to hydrogen is particularly dependent on the supply chain being available at the right time, in the right quantities and in the right place.

There are also political risks for all renewable and decarbonised gases. This could be negative publicity following an incident (which may not be in Australia) that could affect public acceptance and halt the roll out. Other areas along the supply chain could involve the use of energy crops, resource competition, and/or carbon capture and storage that could present significant political risks.

Finally, there are financial risks that need to be addressed at a national level – these include business models for renewable and decarbonised hydrogen and methane production, carbon capture and transport. Support for research, trials and pilots to demonstrate hydrogen networks will be important prior to any roll out.

Appendix A Stakeholder Engagement

As part of the national plan development, DNV consulted with a wide range of expert stakeholders, from both gas networks and pipeline operators and external organisations, as detailed below.

Gas network and pipeline operators

- Energy Networks Australia (ENA)
- Australian Pipeline & Gas Association (APGA)
- Australian Gas Infrastructure Group (AGIG) consisting of Dampier Bunbury Pipeline (DBP), Australian Gas Networks (AGN) & Multinet Gas Networks (MGN)
- APA
- ATCO
- AusNet Services
- Evoenergy
- Jemena
- TasGas Networks

External organisations

- Australian Government - Department of Industry, Science, Energy and Resources (Gas Taskforce / Australian Hydrogen Strategy)
- SA, Department of Energy & Mining
- WA, Department of Jobs, Tourism, Science and Innovation (WA Renewable Hydrogen Unit)
- WA, Department of Mines, Industry, Regulation and Safety
- Energy Policy WA
- WA, Economic Regulatory Authority
- Victoria, Department of Environment, Land, Water and Planning
- Energy Safe Victoria
- Australian Energy Market Operator
- BioEnergy Australia
- Australian Hydrogen Council
- CSIRO
- Future Fuels CRC
- Gas Appliances Manufacturing Association Australia (GAMAA)

The engagement with the gas networks and pipeline operators involved numerous workshops and 1-1 interview discussions with key stakeholder representatives. Externally, DNV carried out the following engagement.

External stakeholder workshop

On 2 February, we held a 2-hour external workshop, covering:

- The role of gas networks in a decarbonised energy system in 2050
- How policy, regulatory and other responsibilities should be managed, to ensure that parts of the plan don't fall through the cracks
- The tenets of the plan, and how networks should interact with elements outside of their direct control
- How research and demonstration projects can be coordinated nationally to reduce the need for state-level duplication

National policy focused discussion

On 16th of February 2021, DNV held a further discussion with relevant representatives of Australia's National Hydrogen Strategy and Gas Taskforce in the Australian Government Department of Industry, Science, Energy and Resources. The discussion was focused on national policy issues arising from Australia's National Hydrogen Strategy.

Appendix B Existing Natural Gas Specification (AS 4564)[55]

Characteristics and Components		Limit
Wobbe Index	Minimum	46.0 MJ/m^3
	Maximum	52.0 MJ/m^3
Higher heating value	Maximum	42.3 MJ/m^3
Oxygen	Maximum	0.2 mol%
Hydrogen sulphide	Maximum	5.7 mg/m^3
Odour intensity	Minimum	Where required, detectable at a level not exceeding 20% LEL
Total sulphur	Maximum	50 mg/m^3
Water content	Maximum	Dewpoint 0 °C at the highest MAOP in the relevant transmission system (in any case, no more than 112 mg/m^3)
Hydrocarbon dewpoint	Maximum	2.0 °C at 3500 kPa gauge
Total inert gases	Maximum	7.0 mol%
Oil	Maximum	20 mL/TJ

Appendix C Impact of Hydrogen on Gas Properties

Property	Impact of 10% Hydrogen	Impact of 100% Hydrogen
Higher Heating Value (HHV): HHV is a measure of how much energy is produced from burning a fuel, initially at 25 °C, and returned to 25 °C. Hydrogen has a lower HHV than natural gas.	Addition of hydrogen may decrease burner efficiency if the burner is not tuned correctly. An increased volume of gas will be required to generate the same level of energy which may have implications on infrastructure.	
Relative Density (RD): The addition of hydrogen lowers the relative density.	Addition of hydrogen will increase the gas velocity and pressure loss experienced.	
Wobbe Index (WI): WI is a function of HHV and RD and is a good indication of combustion behaviour and therefore the manufacturer's specified range over which appliances and burners can operate safely. The addition of hydrogen decreases the WI. A WI below the manufacturer's guideline can lead to flame lifting, flame blowouts, release of unburned gas and increased generation of carbon monoxide.	Where the WI of the 'original' natural gas is close to the lower limit, the addition of 10% hydrogen could lead to non-compliance of burners and appliances.	Burners and appliances tuned to natural gas will not be compliant for pure hydrogen.
Flame Speed Factor: Flame speed is an indication of flame stability and the addition of hydrogen increases the flame speed.	Addition of 10% hydrogen may impact flame stability.	During a depressurisation event, pure hydrogen could result in flash back.
Sooting Index: Sooting Index indicates the potential for incomplete combustion and formation of carbon monoxide. The addition of Hydrogen will decrease the sooting index, meaning combustion is more complete.	Addition of hydrogen improves the completeness of combustion.	
Flammability Limit: The lower and upper flammability limits indicate the concentration of a 'gas' and air mixture that forms an explosive atmosphere. The addition of hydrogen increases the flammability range.	The addition of hydrogen will impact on hazardous area calculations and increase the size of hazardous area zoning.	

[55] Australian Standard AS 4564:2020 General Purpose Natural Gas https://www.standards.org.au/

Property	Impact of 10% Hydrogen	Impact of 100% Hydrogen
Flame Emissivity: Flame emissivity is used to describe the colour we see when a fuel is burned. Where a typical natural gas flame is blue with a yellow tip, pure hydrogen produces light in the ultraviolet range and therefore is not in the visible range, leading to the requirement for flame detectors.	At 10% hydrogen, the flame will look similar to natural gas.	Pure hydrogen produces light in the ultraviolet range, requiring flame detectors.
Joule Thomson Coefficient: The Joule-Thomson effect describes how the pressure and temperature characteristics of a gas interact. Pure hydrogen is rare in that it has a negative Joule-Thomson coefficient; this means that any pressure reduction will lead to an increase in temperature downstream of the reduction. The interaction of this effect in the transmission network needs to be considered but does not pose a risk for distribution networks.	For a 10% hydrogen blend, the temperature may increase with a pressure drop, however the impact of this will be low.	For pure hydrogen any pressure reduction will lead to an increase in temperature downstream of the reduction.
Minimum Ignition Energy: Minimum ignition energy is a measure of the energy required to get a fuel to the temperature required for ignition (within the flammability limits). The addition of hydrogen reduces the minimum ignition energy.	For a 10% hydrogen blend, the minimum ignition energy is similar to natural gas.	For pure hydrogen, the minimum ignition energy is significantly lower than natural gas.
Auto Ignition Temperature: Auto-ignition temperature is the minimum temperature required to ignite a flammable mixture. The addition of hydrogen reduces the auto-ignition temperature.	For a 10% hydrogen blend, the auto ignition temperature is similar to natural gas.	The auto-ignition temperature of pure hydrogen is not significantly lower than pure methane but is suspectable to spontaneous ignition when released into the air at low pressure.
Moisture Vapour: Moisture content in natural gas is strictly controlled by AS 4564:2020 in order to prevent corrosion of pipelines.	Increasing the concentration of hydrogen in a gas mixture will increase the amount of water produced during combustion which could impact the end user.	
Methane Number (MN): MN is used to describe the “knock” characteristics with respect to internal combustion engines and therefore the manufacturer’s specified range over which engines can operate efficiently and reliably.	The addition of hydrogen increases the MN.	

Appendix D Pipeline Specification for Biomethane

For biomethane with contaminant limits according to AS 4564:2020 this process is straightforward as from an integrity perspective the biomethane is similar to natural gas and pipelines designed according to AS2885,1 should be compatible. A design condition change assessment according to the requirements of AS2885.3 will still be required as the process fluid has changed. The parameters to be reviewed are shown below:

- The location class
- The boundaries of the location class and the location of physical barriers or other features that could restrict the movement of these boundaries
- Management of risk to the public, property, environment or to the pipeline
- The protection measures required against third-party damage
- The physical characteristics of the pipeline, including the diameter, wall thickness, SMYS, fracture toughness properties, strength test pressure and leak test pressure
- The physical condition of the pipeline as determined from records of the operation and maintenance and from reports of examinations, inspections and monitoring, including those pertinent to corrosion mitigation
- The design pressure
- The actions required for approval of a revised maximum operating pressure

In the case where contaminant levels are relaxed compared to AS4564 then a specific corrosion risk assessment would be needed to determine the actions required to maintain pipeline integrity.

Some regulatory regimes allow higher oxygen limits for specific pressure tiers. For example, the UK HSE allows 1% oxygen at pressures up to 38 bar. In Europe many of the national rules/specifications specify very low oxygen limits for gas which will enter underground storage and higher limits for transmission quality gas (e.g. the German DVGW regulations). If the volumes of unconventional gas entering the network are small compared to conventional gas, then dilution may allow the underground storage limits to be met. If larger volumes of unconventional gas are injected, then modelling or other measures may need to be instituted in order to allow the underground storage of gas from the transmission network.

The German DVGW organisation has issued several technical guidelines which address the issue of oxygen in renewable gas sources. These are:

- G 262 Usage of gases from renewable sources in the public gas supply
- G 267 Oxygen content in high pressure grids

G 262 states “For gases in gas networks with a maximum operating pressure (MOP> 16 bar), the oxygen content at the transfer point to gas storage facilities and, where applicable, at border crossing points, be no more than 0.001 mol.% as a daily average”.

G 267 recommends determining oxygen content for gases that may enter cross-border transit or underground storage facilities (UGS) using a volume weighted 24-hour moving average. For networks that are indirectly connected to cross-border transit or UGS it requires network modelling to assure that oxygen levels are ≤0.001mol.% after mixing with conventional gases in the networks. For networks that have no connection to cross-border transit or UGS and are <16 bar MOP then an oxygen content of ≤3% is permitted.

It is thus recommended that the oxygen limit in AS 4564:2020 is reviewed considering international best practice to facilitate biomethane injection at lower pressure tiers.

ABOUT DNV

We are the independent expert in risk management and assurance. Driven by our purpose, to safeguard life, property and the environment, we empower our customers and their stakeholders with facts and reliable insights so that critical decisions can be made with confidence. As a trusted voice for many of the world's most successful organizations, we use our knowledge to advance safety and performance, set industry benchmarks, and inspire and invent solutions to tackle global transformations.

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We provide assurance to the entire energy value chain through our advisory, monitoring, verification, and certification services. As the world's leading resource of independent energy experts and technical advisors, we help industries and governments to navigate the many complex, interrelated transitions taking place globally and regionally, in the energy industry. We are committed to realizing the goals of the Paris Agreement, and support our customers to transition faster to a deeply decarbonized energy system.

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