Research Report

Identifying the commercial, technical and regulatory issues for injecting renewable gas in Australian distribution gas networks

Prepared for Energy Networks Australia

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EXECUTIVE SUMMARY

The objective of the current report is to identify the main technical, commercial, and regulatory issues associated with injecting renewable gas into gas distribution networks across Australia. These issues are explored in more depth for the situation where up to 30% of hydrogen is injected into gas distribution networks. The report builds on an extensive literature review on the international status of production and injection of renewable gas into gas networks.

The key findings from this report are summarised below.

Network material performance

Gas distribution systems consist mainly of plastic pipes, largely polyethylene, and a small amount of PVC. Polymer degradation under renewable gas service, including hydrogen, has not been found to be an issue. Contaminants in hydrogen, SNG, biogas or renewable / natural gas blends may affect plastics, but requires further study.

Leakage rates due to permeability of plastics to hydrogen are higher than for methane, but are considered insignificant. Elastomeric materials used for seals and gaskets have higher permeability rates than polyethylene, but the total loss rates are still very low from economic and safety points of view.

In general, the metallic materials of interest have a low permeability to hydrogen and so leakage of hydrogen through steel, copper and other metallic pipe is not considered to be an issue. However, consideration should be given to the manner in which metallic pipes and pipework is joined to other sections and to auxiliary equipment. These joints and seals may allow leakage of the hydrogen gas through the seal material or if there is insufficient ‘tightness’ of the seal/joint.

The influence of hydrogen on the integrity of a metallic pipe or component depends on a number of factors which can be grouped under those related to the metallic material itself and those related to how the pipeline is operated. The former includes the steel’s strength, chemistry, impurities, microstructure, surface condition and processing and the latter includes the time, temperature, pressure, loading mode (including cyclic loading and its frequency), hydrogen concentration and gas purity.

Steel, and other ferrous alloys, can be susceptible to hydrogen embrittlement and the hydrogen content at which this susceptibility starts is very low. Although the hydrogen embrittlement susceptibility has been shown to increase as the hydrogen content in the gas increases, the effect does not escalate significantly with hydrogen content. Consequently, the general consensus across a number of studies is that methane with hydrogen additions can be safely transported through distribution networks at levels up to 25% hydrogen. Given that the old “towns gas” system contained hydrogen levels up to 50% and operated without significant issues related to the hydrogen content, it may be considered that the 25% hydrogen limit is conservative and levels up to 30% can be permitted without significant issues.

In the gas distribution system, the strength of the steels and other ferrous alloys used is relatively low and at these low strengths (and the associated low operating pressures) the alloys are not particularly susceptible to hydrogen embrittlement. Additionally, at these low stresses the steel pipes are considered immune to hydrogen cracking which requires a higher stress level to initiate cracking.

The most significant issue for any steel pipeline operating in a hydrogen containing environment is fatigue. Hydrogen additions can increase the fatigue crack growth rate as the hydrogen content in the methane increases. All pipelines undergo some pressure cycling during their life, but extended pressure cycling promotes the chances of fatigue cracks initiating and growing.

Consequently, it is important to minimise pressure cycling for any hydrogen containing steel pipeline.

Copper alloys are generally resistant to hydrogen embrittlement and so copper pipes are resistant to any material related issues when exposed to methane containing any level of hydrogen or biogas.

Customer material and commercial aspects
Domestic gas appliances and industrial pre-mixed gas burners are able to cope with biogas, SNG and the introduction of significant percentages of hydrogen into natural gas (up to levels of 30%). However, it is recommended that burners in domestic appliances and industrial pre-mixed burners are tested and approved for all levels of hydrogen addition above 5%, although they may require minimal changes even at 30% hydrogen addition. It may also be necessary to slightly increase the final regulated pressure at the entrance to customer premises to allow higher gas velocities in the burner ports. Burners may require design changes to inlet and exit fuel injector or mesh opening and changes to automatic controls on fuel and air flow-rates especially if gas composition varies significantly.

Industrial non-premixed burners used for boilers and kilns may require modifications or adjustments to operation at all levels of hydrogen addition, but in many cases modifications may be minor, even at up to 30% hydrogen addition if burners have flexible designs. Gas turbine burners are generally sensitive to fuel quality and variability and changes may need to be made for additions of even 1% hydrogen. Significant work is required to use gas with more hydrogen or varying amounts of hydrogen. Turbine manufacturers have solutions, but the cost / benefit ratio needs to be assessed in each case.

Like gas turbine burners, gas engines are sensitive to gas mixture concentrations. Some recommendations for use of 2%-5% hydrogen in natural gas engines have been made, but case by case implementation and testing may be required, if there is variability of natural gas composition. Furthermore, this study shows that high strength steel CNG vessels (both stationary and on board) should not be used with hydrogen concentrations above 2% and needs to be thoroughly investigated because of the difficulties involved in retrofitting the existing fleet.

The addition of hydrogen to natural gas reduces the volumetric heating value and the Wobbe Index. Measures need to be taken to keep the Wobbe Index within the acceptable range to ensure renewable gas is compatible with appliances and plant equipment. Another implication of the lower volumetric heating value of hydrogen-methane mixtures is that higher volumes of gas will be required to provide the same amount of energy, and this may require additional compressors. Furthermore, adding hydrogen reduces the density of natural gas, and increases the required volumetric flow-rate to achieve the same rate of energy delivery. Consequently, velocity and pressure drop in distribution pipelines also increase for the same energy delivery.

The locations, flow-rates and variability in flow-rate of hydrogen injection will influence the composition of blended gas throughout distribution networks. It may be necessary to use hydrogen storage tanks or pipelines to buffer injection rates if hydrogen supply is intermittent, and likewise it may be necessary to locate injection points at pressure let-down stations, and multiple other locations, to prevent wide variation in hydrogen concentration throughout the network.

Accurate measurement of composition and flow-rate are required for gas pricing. Instruments for determination of gas composition and for leak detection will need to be upgraded for renewable gas duty. Flow-rate metering will be more difficult if hydrogen concentration varies, because it will cause variation in gas density.

Regulatory and safety considerations
Various Acts and Regulations cover the supply and distribution of natural gas throughout the Australian states. Gaps in these Acts and Regulations for renewable gas blends with natural gas

relate to materials selection, ensuring leak-tight components, quality assurance of metering and calculation of gas composition, appliance suitability, isolation procedures, modifications to the type and amounts of odourant added, and possibly separation of gases to supply customers who use gas for heating with a different composition to those who require methane as a chemical feedstock. These gaps can be addressed by historical and overseas experience with renewable gases, but may require further research to address issues pertinent to Australian conditions.

Safety issues relate mainly to explosion and flame radiation exposure. The risks are slightly more severe near to the release with addition of hydrogen due to widening of flammability limits and increase in flame speed. Explosion over-pressures are slightly higher and flame radiation is slightly higher closer the release if hydrogen is blended with natural gas. However the size of flames reduces slightly. For addition of hydrogen up to 15%, the differences from natural gas flames and explosions are not significant. The set points for alarms based on the lower flammable limit of methane will only need minor adjustment. However, many types of leak detectors do not detect hydrogen, although they will still detect methane in the presence of hydrogen, so leak detector suitability will need to be reviewed and many may need to replaced.

Safety issues relate mainly to explosion and flame radiation exposure. The risks are slightly more severe near to the release with addition of hydrogen due to widening of flammability limits and increase in flame speed. Explosion over-pressures are slightly higher and flame radiation is slightly higher closer the release. However the size of flames reduces slightly. For addition of hydrogen up to 50%, the differences from natural gas flames and explosions are not significant.

Upstream issues and lifecycle cost implications
An upstream issue is to ensure that only low percentage hydrogen is used in high strength transmission pipelines, and avoidance of significant pressure cycling in such transmission lines. Use of dedicated hydrogen transmission lines with injection into low to medium pressure networks could be used to overcome this issue.

The addition of hydrogen for the LNG export markets is not an option at this stage due to tight controls of gas specification. However, SNG and biogas would be possible.

There are a range of upstream costs associated with the manufacturing, transport, storage and injection of hydrogen that were outside the scope of this report and need to be further studied, including:

- Costs of production of renewable hydrogen
- Compression and transport of hydrogen to the injection location/s
- Storage of hydrogen at the injection location/s
- Construction of metering and test stations for injection
- Operation and maintenance cost associated hydrogen manufacturing, transport and storage
- Costs associated with scaling up all systems to cope with market growth
- End of life costs, decommissioning
- Tariff structures and arrangements

In addition to the costs associated with manufacturing, transport, storage and injection of renewable gas, this study has identified a range of life cycle cost implications, including:

- Costs associated with testing and replacement materials and joints in networks
- Costs for customers, including a premium may be charged that reflects the extra costs incurred by network operators for hydrogen manufacture and handling.
- Costs associated with assessments of consumer burner equipment and possible replacement or modifications to such equipment.
- Cost associated with meeting commercial specifications including costs associated with delivering gas within the specification limits for heating value, Wobbe Index, composition and ensuring accuracy of flow-rate monitoring.

- Cost associated with isolation some customers in the network from a blended gas supply.
- Cost associated with risk and regulation including quality testing and assessment of quantity based on plant capacity and contractual delivery obligations.

Gaps in knowledge

The following areas require further investigation:

- More comprehensive study of leakage rates of hydrogen from all types of plastic pipes in a range of pressures and geographic locations.
- Research into the long term performance of materials transporting and storing natural renewable gas and development of new materials with improved performance characteristics and degradation resistance.
- Impurities or containments in hydrogen, SNG, biogas or renewable / natural gas blends may affect network materials and costumer equipment and require further study.
- The full extent of changes required to the network materials, instrumentation, customer appliances and plant equipment need to be understood for renewable gas and in particular hydrogen-methane mixtures.
- The changes required to industrial and domestic burners and control systems has only partially been addressed in previous work and needs to be more comprehensively addressed on a case by case basis.
- Improved gas composition, flow metering, as well as leak detection instruments may need to be developed.
- Assessment of distribution networks for physical bottlenecks and bottlenecks in the approval processes for hydrogen injection.
- Detailed studies of the effect of injection locations and variability of injection rates on gas composition in specific networks will need to be performed to gain a fuller appreciation of the costs of transport, metering and extra storage.
- Safety considerations need to be reviewed for hydrogen generation, transport and injection.
- Uncertainties regarding the lifecycle costs for hydrogen production, transmission, storage and injection need to be reduced.

1. INTRODUCTION

This report contains a qualitative review of the technical, commercial, regulatory and upstream factors, relevant to network owners, operators and users that would need to be considered if renewable gas was to be transported through a gas distribution system in Australia. This review is complemented by a semi-quantitative assessment of the issues related to varying concentrations of hydrogen injection up to 30% volume.[1] The report also addresses associated costs implications of hydrogen injection into networks and identifies gaps in knowledge.

This report has been prepared for Energy Networks Australia. ENA has recently released its vision for the gas distribution sector.[2] This vision outlines how gas and the gas distribution networks can contribute to a low carbon economy. A component of this vision is to promote the development of renewable gas, in particular hydrogen, and whether this gas can be injected into the network.

Natural gas transportation and distribution networks can potentially play a role in transporting and storing renewable energy in the form of hydrogen or synthetic natural gas or biogas for long term re-use, without degradation, and for stabilising the electricity grid.

A better understanding of potential issues for injecting renewable gas into the Australian gas distribution networks is required to ensure that operators can inject, transport and utilise renewable energy safely and effectively.

This review will include the aspects listed below:

- *Performance of network materials* including the long term integrity of steel, copper and plastic piping systems and their compatibility with renewable gas.
- *Performance of customer appliances and plant equipment* including the effects of renewable gas on burners, storage vessels and the Wobbe Index.
- *Commercial aspects* like the effects of renewable gas and methane blends on the heating value and the accuracy of metering systems.
- *Regulatory and Statutory aspects* including a review of applicable regulatory frameworks, Codes and Standards and identification of gaps.
- *Risk aspects* other than those already applicable to natural gas, including potential changes to current risk management practices to ensure worker and public safety.
- *Upstream aspects* including implications for transmission pipelines and Australia's LNG export industry.

Report use

This report provides a greater understanding and, where possible, quantifies the technical, commercial, regulatory, and upstream issues associated with the injection of renewable gas, in particular hydrogen into existing gas distribution systems at levels up to 30%.

The report does not deal with levels of hydrogen injection above 30%. It should be noted that anticipated satisfactory performance of networks with hydrogen levels up to 30% does not imply that the concentration of hydrogen can be increased above 30% without issue.

[1] The percentage of hydrogen in the gas mixture is always measured in % volume, unless otherwise noted.
[2] (Energy Networks Australia 2017)

2. INJECTING RENEWABLE GAS IN AUSTRALIAN DISTRIBUTION NETWORKS

This report builds on an international status review of renewable gas production and injection into the natural gas distribution networks[3]. Extracts from this report are provided below.

Hydrogen
Availability of excess renewable electricity from wind and photo-voltaic electricity is becoming a reality in some electricity markets, providing an incentive for production of hydrogen by electrolysis. Proton exchange membrane electrolysers are being used in some projects in Europe because of their high efficiency and ability to respond to rapid load fluctuations. In Australia, concentrated solar thermal heat with molten salt storage may be used to produce additional renewable electricity. This will extend the daily peak production of renewable electricity into the evening and may add to the need to use electrolysis for seasonal storage of renewable energy.

Furthermore, low carbon hydrogen can be produced from fossil fuels by steam methane reforming or coal gasification when combined with carbon capture and storage.

Synthetic natural gas and biogas
Renewable synthetic natural gas (SNG) is currently produced at small scale by anaerobic digestion of biomass or waste (biogas), and can be combusted on-site to produce power and heat, or injected into the natural gas network, bearing in mind it has a high carbon dioxide content. Renewable SNG can also be produced by methanation of renewable hydrogen or by gasification of biomass or crude bio-liquids (bio-SNG). Solar thermal gasification of biomass is an option which is currently being investigated in Australia because it increases the yield of product.

Demonstration projects
There have been many small scale demonstration projects of renewable “power to gas” in Europe. Up to 20 of these have included injection of either hydrogen or SNG into the gas network at rates of 200 Nm^3/h or less. The largest project is the ETOGAS / Audi project, which uses alkaline electrolysers to produce over 1000Nm^3/h of hydrogen, which is then converted to SNG.

Cost and scale up
Production of hydrogen and SNG from biomass and waste has lower cost than the electrolysis route, and is already established at a larger scale than electrolysis. Although, biomass gasification does not have the benefit of consuming excess renewable electricity and balancing the electricity grid, It could be used to increase hydrogen production rates whilst technology improvements and cost reductions in electrolysis are occurring. The costs of producing and transporting hydrogen from renewable electricity and electrolysis are expected to reduce dramatically over the coming 5 -15 years through technological learning.

There are costs related to transport of hydrogen, which provides an incentive and opportunity to use the existing natural gas network for transport. In addition supportive market mechanisms and policy settings may be required, such as:

- payments for use of excess renewable electricity and grid stabilisation;
- premium prices for seasonal storage of renewable gas;
- a premium for avoiding upgrades to electricity infrastructure;
- finance for large scale grid stabilisation and renewable gas production projects; and
- a price on carbon to incentivise renewable gas (including hydrogen).

There is significant potential for hydrogen and SNG injection into natural gas networks in Australia and this report will illustrate the main issues to be addressed to achieve this potential.

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[3] (Energy Pipelines CRC 2017)

3. TECHNICAL ASPECTS: PERFORMANCE OF NETWORK MATERIALS

Production of biogas and bio-SNG, which is very similar to natural gas in terms of properties, is a well-established process using available commercial technologies. It can be mixed with natural gas in transmission and distribution networks with no or very limited modifications. Therefore the remainder of this section focusses mainly on the use of hydrogen in gas distribution networks.

As of 2007, 65 million tonnes of hydrogen was produced in the USA per annum (IEA, 2007). This hydrogen is used for oil refining, food production, treating metals, chemical production and in energy storage. As of 2006 there were approximately 1200 miles of hydrogen pipelines in the USA and these generally are used to transport compressed hydrogen at pressures less than 1000psi (6.9MPa). Some of these pipelines have been in service for 80 years[4].

It should also be remembered that in many countries, the locally made and distributed "towns gas" was a methane/hydrogen/carbon dioxide blend containing 30-50% hydrogen.[5] At present the Hong Kong "towns gas" based distribution system operates with approximately 50% hydrogen.

Consequently, there is extensive experience of the use of steel pipelines for hydrogen transport and there are existing codes, standards and technical reports covering the transport of hydrogen, for example ASMEB31.12 Hydrogen piping and pipelines and the Technical Reference for Hydrogen Compatibility of Materials.[6]

The natural gas distribution network contains a range of materials and operates at pressures below 1050kPa (as specified in AS4645 and depicted in Appendix A). As the pressure decreases the pipeline materials progress from steel to grades of plastics.

The following sections consider the issues posed by injecting hydrogen into the natural gas distribution network in terms of both leakage and integrity. Key issues relevant to the potential transport of hydrogen through steel transmission pipelines are discussed in section 8.1.

3.1. Plastic piping systems and elastomer seals

The majority of plastic pipes utilised in the Australian gas distribution networks are different grades of polyethylene, PE. The two most common grades of PE in use are PE63 a high density PE and PE80 a medium density PE. PE100, which is a new grade of high density PE, is the current state of the art PE type for plastic pipes and it is anticipated use of PE100 will increase over time. A relatively small amount of polyvinylchloride (PVC) is utilised at present.

From the available literature it has been found that the major technical aspect associated with transporting hydrogen in plastic pipes is potential permeation of hydrogen, since hydrogen is a smaller molecule than methane. However, as will be described in this section, this leakage is not economically significant and does not change the risk profile from using gas in networks at levels of hydrogen up to 30%.

<u>Polymer degradation</u>
Polymer degradation occurs via UV radiation, heat or chemical reaction. A study investigating the ageing of two polymer materials, polyethylene PE100 and polyamide PA11, at various pressures up to 100bar using a 20% hydrogen / 80% methane mixture, found that no significant change in mechanical properties was observed over a period of 3 years. Therefore it was concluded that no significant degradation or damage to polymer materials used in the gas transport system is expected. This finding can be extended to the majority of the elastomeric materials also used in the gas transport system namely Butadiene Styrene (SBR) and Butadiene-Acrylontrile (NBR) used as O-rings, diaphragms, gaskets and seals.[7]

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[4] (Lipman 2011)
[5] (Oney 1994, Haeseldonckx 2007)
[6] (San Marchi 2012, Fekete 2015)
[7] (Melaina 2013)

Hydrogen due to its non-polar nature is not anticipated to interact with polyethylene. However, while hydrogen itself will not interact, the presence of contaminants in hydrogen gas may be detrimental to the pipeline materials and this will greatly depend on their concentration. No study examining this degradation due to impurities is currently available.

Leakage of hydrogen

The permeation of hydrogen gas is higher than methane for all common polymer and elastomeric materials used in gas transport lines as shown in the table below. The table below shows the permeation coefficient for common plastic and elastomeric materials used in the gas pipeline. While the permeability of hydrogen is greater for the elastomeric materials, used as O-rings and seals, leakage is assumed to occur at the pipe wall, since the surface area of the pipe is higher[8].

Table 1: Permeation Coefficient in volume (10^{-3}xft-mil/ft/day/psig) of hydrogen gas for plastic pipe materials and elastomeric materials.

Material	Hydrogen	Methane
MDPE(PE2708)	1.43	0.29
HDPE(PE3608)	1.09	0.16
HDPE(PE4710)	1.09	NA
PVC	0.95	NA
Natural Rubber	28.39	NA
Butyl Rubber	4.27	NA
SBR	23.02	NA
Neoprene	7.67	NA
NBR	9.12	NA

*(data taken from appendix A in report by Melaina 2013)

Table 2 shows the calculated gas lost under three different pressures for a HDPE pipe. The gas lost is calculated using literature values of permeation data. Gas lost increases with pressure. When a pressure of 60psig[9] is used for a 20% hydrogen mixture, 1.7 times the amount of hydrogen is lost compared with methane. Despite this loss, a report from GTI concluded that from an economic point of view this amount of gas loss was insignificant.

The GTI report also highlighted the need to perform further investigations testing existing plastic pipe materials as well as future plastic pipe materials including elastomeric seal materials at hydrogen concentrations and pressures likely to be employed.[10]

Table 2: Calculated Gas Loss Rate in volume (ft3/mile/year) based on literature data for HDPE pipe diameter 1inch, wall thickness 0.1inch at various operating pressures.

Hydrogen Content	At 60 psig (414 kPa)			At 3psig (21kPa)			At 0.25psig (1.7kPa)		
	H_2	CH_4	Total	H_2	CH_2	Total	H_2	CH_4	Total
0%	0.0	49.4	49.4	0.0	2.5	2.5	0.0	0.2	0.2
10%	32.9	44.5	77.4	1.6	2.2	3.9	0.1	0.2	0.3
20%	65.9	39.5	105.4	3.3	2.0	5.3	0.3	0.2	0.4
50%	164.7	24.7	189.4	8.2	1.2	9.5	0.7	0.1	0.8
100%	3239.3	0.0	3293	16.5	0.0	16.5	1.4	0.0	1.4

*(data taken from appendix A in report by Melaina 2013)

Data presented in Table 2 is calculated using the following equation: $V = P^*(A/t)^* \Delta p$, where:

- A = surface area of pipe
- t = pipe wall thickness
- Δp = pressure difference between internal and external surface of pipe

[8] (Klopffer et al 2001, Melaina et al 2013)
[9] 60psig is equivalent to 414 kPa and most relevant to the initial part of the distribution network, while the lower pressure ranges of 3 and 0.25 psig are more typical of the mains after pressure reduction.
[10] (Melaina 2013)

The permeability of non-metallic materials will depend on the material's microstructural characteristics, including orientation, crystallinity, moisture content, filler content, presence of plasticizers etc. The effective hydrogen transport properties of elastomers (including rubber, neoprene and a range of polymers) are relatively well known at room temperature and at low pressure and, in general, are the same across all of these materials. Hydrogen diffusion and permeability through semicrystalline thermoplastics is relatively constant and an order of magnitude lower than for elastomers. However, data on epoxies is limited but they are thought to have similar permeation as thermoplastics. Composites made of these epoxies had lower permeation of hydrogen that the related epoxy.[11]

3.2. Steel piping systems

When hydrogen is put into a steel pipeline used in gas transmission and distribution systems, some of it dissociates and then is absorbed into the pipeline wall as atomic hydrogen due to the pressure of the gas.[12] However, the permeability of hydrogen through the steel is insignificant and so it can be considered that there is no leakage of hydrogen from a pipeline through the steel.

Nevertheless, the absorbed hydrogen can affect the properties of the linepipe through hydrogen embrittlement, resulting in a deterioration of the mechanical properties of the steel.[13]

The susceptibility of a particular grade of steel to hydrogen embrittlement depends on a number of factors, including the steel's strength, chemistry, impurities, microstructure, surface condition and processing.[14] Operating parameters, such as time, temperature, pressure, loading mode (including cyclic loading and its frequency), hydrogen concentration and gas purity also have a bearing on the performance of the steel in service.[15] These factors related to hydrogen embrittlement susceptibility of steels are dealt with in more detail later in this section.

It is worthwhile noting up front that for the gas distribution system, the strength of the steels and other ferrous alloys used is relatively low and at these low strengths (and the associated low operating pressures) the alloys are not particularly susceptible to hydrogen embrittlement.

Other steel mechanical properties, such as fracture toughness, can be affected by the presence of hydrogen.[16] But, as for the strength related hydrogen effects, issues with fracture toughness can also be avoided by operating at low pressures.

Linepipe strength
In general, steels used for pipelines are classified under the Standard API 5L. Distribution systems use low grades of steel, usually grade A, B (lowest strength grades), X42 and X46. The lower strength of these steels and other ferrous materials, combined with the low gas pressure in distribution systems, means that steel distribution pipelines are not particularly susceptible to hydrogen embrittlement. Additionally, at these low stresses the steel pipes are considered immune to hydrogen cracking which requires a higher stress level to initiate cracking.[17]

Welds in pipelines
Pipelines are constructed from lengths of pipe welded together. The microstructure of the weld zone is different to that of the parent pipe and so offers a potentially higher susceptibility to hydrogen embrittlement than the parent steel.[18] Tensile tests on welds in hydrogen environments have shown them to have a significantly reduced ductility (as measured by reduction in area) compared to equivalent samples tested in air. The trends reflected what was observed for parent

[11] (Barth 2013)
[12] (Fekete 2015)
[13] (Fekete 2015, Zhou 2010)
[14] (Messaoudani 2016, Briottet 2012, Barthelemy 2011, San Marchi 2012, Zhou 2010)
[15] (San Marchi et al 2016, Messaoudani 2016, Barthelemy 2011, San Marchi 2012, Zhou 2010)
[16] Barthelemy (2009)
[17] (Zhou 2010)
[18] (Fekete 2015, San Marchi 2012)

pipe tested in hydrogen and air. Similarly, welds had their fatigue crack growth rate accelerated in hydrogen containing environments to the same extent as for the base material. However, the fracture toughness of weld zones, particularly the heat affected zone, was in some tests lower than for the base material in a hydrogen containing environment, although both were degraded related to material tested in air.[19]

Hydrogen gas purity

As hydrogen embrittlement requires the diffusion of hydrogen into the steel, factors that change the ease of this diffusion and its interaction with the steel, such as impurities in the hydrogen, affect the susceptibility of the component to cracking or embrittlement. The effects of these impurities can be detrimental (for example, hydrogen sulphide and carbon dioxide[20]) or beneficial (for example, oxygen[21]). Carbon and sulphur species present in the hydrogen gas can also inhibit the embrittlement of the steel[22]. Methane and nitrogen have been shown to have no effect on hydrogen embrittlement susceptibility. Tests on water have shown that it can have either an accelerant or decelerant effect on the crack growth rate, but in general is considered to have a slight accelerant effect or no significant effect at low levels.[23]

Hydrogen pressure

For low strength X42 steel, hydrogen embrittlement (as measured by the change in reduction in area) was shown to increase with increasing hydrogen pressure, reaching a plateau at about 7MPa and increased slowly across higher pressures.[24]

Across a range of steels, including those used for transmission and distribution systems, hydrogen decreased the material's fracture toughness and this effect increased as the hydrogen pressure was increased.[25] Measurement of the threshold stress intensity factor showed that for both medium/high (X65 / X70) and high strength steels (X80) the stress intensity factor decreased with increasing hydrogen pressure. However, the lower strength steels demonstrated a lower susceptibility to hydrogen embrittlement than the higher strength steels.

Increasing hydrogen pressure also increased the fatigue crack growth rate across a range of steels. A study on X42 steel showed that the fatigue crack growth rate in hydrogen was 150 times that in nitrogen at 6.9MPa.[26] Consequently, fatigue has to be considered a significant issue for high pressure pipelines. The implications for high pressure pipelines are further discussed in section 8.1.

Pressure cycling

Pipelines, particularly transmission pipelines, can be used for gas storage and cycled through line pack, usually once or twice a day. Distribution systems can also be exposed to pressure cycles. This pressure cycle differential and low cycle rate can promote the formation of fatigue cracks in steels and the presence of hydrogen has been found to exacerbate the fatigue crack growth rate of pipeline steels.[27]

For distribution systems, operating at low pressures, the steel can still be susceptible to accelerated fatigue crack growth rates and reduced endurance limits. The cyclic stress intensity factor of the steel is also decreased by the presence of hydrogen, reducing the fatigue life.[28] Consequently, to avoid fatigue in distribution systems it is important not to pressure cycle the pipe, or at least limit pressure cycling as much as possible.

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[19] (San Marchi 2012)
[20] (Barthelemy 2009, Barthelemy 2011)
[21] (San Marchi, Somerday 2013, Barthelemy 2009)
[22] (Somerday 2013)
[23] (Nanninga 2010)
[24] (Barthelemy, 2009)
[25] (Barthelemy 2009; Barthelemy 2011)
[26] (Barthelemy 2009)
[27] (Nanninga 2010, Fekete 2015)
[28] (Zhou 2010)

Defects and stress concentrators
Generally speaking, pipelines are designed to be able to tolerate defects and stress concentrators up to a critical size. These critical defects sizes are large enough to ensure that typical defects that are introduced into the pipeline or develop over time do not cause catastrophic failure of the pipeline. However, hydrogen can reduce the ductility of the steel and hence its tolerance to defects and stress concentrators. At the low pressures encountered in distribution networks, this reduction in defect tolerance should not be of concern since the operating pressure applies a low pipe wall stress relative to the strength of the pipe.

Mitigation
Careful selection of the steel used and its operating conditions can ensure that the steel chosen does not suffer from hydrogen embrittlement in service. This is borne out by the fact that, despite laboratory trials showing that pipeline steels can have their toughness, fracture resistance and fatigue resistance degraded by exposure to gaseous hydrogen, there are many thousands of kilometres of operating pipelines transporting hydrogen.[29]

To counter the effects of hydrogen embrittlement of pipelines, hydrogen containing pipelines are run at a much higher safety margin compared to those which do not contain hydrogen. This typically means that they are run at a lower pressure or pipe wall stress.[30]

This reduction in pipe wall stress essentially means that larger wall thicknesses are used for hydrogen containing pipelines as compared to natural gas pipelines. This is turn has a very significant knock on effect on the cost of the pipeline.[31]

The alternative is to mix hydrogen into existing natural gas pipelines and there have been many studies on this option (including the NaturalHy Project, HYSAFE, Roads2HyCom etc[32]). It seems to be generally accepted that additions of up to 20-25% hydrogen into a natural gas distribution systems can be done without damage to the pipeline although some adaptation of the pipeline would be necessary to remove material susceptible to hydrogen cracking or permeability.[33]

Given that the old “towns gas” system contained hydrogen levels up to 50% and operated without significant issues related to the hydrogen content, it may be considered that the 25% hydrogen limit is conservative and injection of hydrogen at levels up to 30% can be done without significant modifications to the network.

3.3. Copper piping systems

Pure copper and most of its alloys are known to be immune to hydrogen embrittlement[34] and so can be used in hydrogen containing environments without concern across a range of pressures.

However, copper alloys containing oxides are susceptible to embrittlement in hydrogen containing environments, leading to a loss of ductility.[35]

The fracture toughness of copper appears to not be affected by exposure to hydrogen.[36]

No information was found on the influence of hydrogen on fatigue crack growth rates of copper alloys exposed to hydrogen.

[29] (San Marchi 2016)
[30] (Fekete 2015, San Marchi, 2016)
[31] (Fekete 2015)
[32] (Zine 2016)
[33] (Babrier, 2013)
[34] (San Marchi 2012, Barthelemy 2009)
[35] (San Marchi 2012)
[36] (San Marchi 2012)

3.4. Other metallic pipe materials

A small percentage of distribution pipes may be made of ductile iron or cast iron. These can absorb hydrogen in the same manner as linepipe grades of steel, but because of the low operating pressure, they are considered not to be at risk of hydrogen damage under normal operating conditions.[37]

3.5. Joints and other components

Consideration should be given to the manner in which metallic pipes and pipework is joined to other sections and to auxiliary equipment. These joints and seals may allow leakage of the hydrogen gas through the seal material (as discussed above) or if there is insufficient ‘tightness’ of the seal/joint. Consequently, the design of joints should be reviewed and the choice of seal materials made to minimise the potential for hydrogen leakage.

Many materials, including those used in regulators, metering and other components, can be degraded by exposure to hydrogen. Whether they are or not depends on the design of the component and the service conditions.[38]

3.6. Life cycle cost implications

Given that the steel used for distribution networks can tolerate hydrogen service at levels up to 30% without issue under appropriate operating conditions, there are no life cycle cost issues associated with the transport of hydrogen containing methane through these pipelines.

Copper is considered to be immune to hydrogen related degradation and so there are no life cycle cost issues associated with the introduction of hydrogen into copper piping systems.

The use of hydrogen/methane mixtures is unlikely to result in any additional life cycle cost implications for plastic pipe materials. This is based on the knowledge that no additional degradation of the plastic pipe material is likely to occur due to the injection of hydrogen - notwithstanding the presence of possible containments introduced with the hydrogen gas.

Depending on the condition of existing seals, joints and sections of pipeline, some replacements may be necessary to minimise the potential for hydrogen leakage.

3.7. Gaps in knowledge

Identified gaps in the knowledge for the injection of hydrogen into current plastic pipe materials are centred on understanding rates of leakage better. While some literature exists on this, a broader and more comprehensive study is required considering different pipe locations (buried under asphalt, buried under soil), pipe materials and pressures.

The influence of hydrogen on the performance of steel, other ferrous alloys and copper is relatively well understood and documented in the literature[39]. Therefore, there is considered to be no significant gaps in the knowledge preventing the use of the existing gas distribution network for the transportation of hydrogen containing methane.

However, additional studies on the hydrogen embrittlement mechanism in high strength steels may be required if pipeline transportation of hydrogen under higher pressures is considered.

[37] (Zhou, 2010)
[38] (San Marchi 2016)
[39] For example San Marchi and Somerday (2012) and Melaina et al (2013).

3.8. Summary of performance of network materials

In general, there does not appear to be an influence of hydrogen on the mechanical properties of polymers and thermoplastics.[40] No data was found on the performance of other materials in hydrogen environments.

It was noted that steel maybe susceptible to hydrogen embrittlement in distribution system under the correct conditions, although the likelihood of this occurring is minimal in the low pressure distribution system. Leakage of hydrogen is also insignificant through steel.

A special note needs to be made in regards to compressors, although it is recognised that the point applies more to transmission than distribution pipelines. By nature, compressors increase the pressure of the gas and so the potential for embrittlement of steel compressor bodies should be assessed on a case by case basis.[41]

Copper and copper alloys are largely impervious to hydrogen leakage through the metal and to any sort of material property degradation (in the absence of oxides in the copper).

There are several other types of non-metallic materials which may be included in distribution networks including in seals, compression equipment, values, O-rings etc. Examples are elastomers (eg butadiene-styrene and butadiene-acrylonitrile), composites, nylon, Teflon and rubber. In hydrogen service, the permeability of these materials has a bearing on their suitability.

It should be noted that there is always the potential for leakage of hydrogen at seals and joints between components and so the quality of these seals should be taken into account when assessing leakage.

The following table provides a checklist of the technical issues that need to be taken into account when injecting renewable gas into distribution networks.

Table 3: Summary of technical issues that need to be taken into account when injecting renewable gas, in particular hydrogen, into distribution networks.

Material	Polymers and PVC	Other non-metallic materials	Steel	Copper	Other metallic materials
Permeability*	Assess	Assess	Not significant	Not significant	Not significant
Hydrogen pressure	Assess	Assess	Assess	Not significant	Not significant
Pipe strength	Not significant	Not significant	Assess	Not significant	Not significant
Mechanical properties	Not significant	Assess	Assess	Assess	Assess
Fatigue	Not significant	Assess	Assess	Assess	Assess
Gas impurities	Assess	Assess	Assess	Not significant	Not significant

* This considers the permeability of hydrogen through the material. Leakage from joints and seals needs to be considered as a separate issue.

40 (Barth, 2013)
41 (Haeseldonckx 2007)

4. TECHNICAL ASPECTS: IMPACT OF RENEWABLE GAS ON PLANT EQUIPMENT

This section foreshadows the main issues that addition of renewable gas may introduce for customer equipment, such as domestic appliances, industrial burners, gas turbine burners, gas engines, and compressed natural gas (CNG) storage vessels. This section mainly deals with the effects of hydrogen addition on the ability of plant and equipment to perform their design functions, as SNG and biogas are not expected to cause many issues due to their similarities with natural gas.

4.1. Appliance performance

Hydrogen as a renewable gas can provide decarbonised energy to residential consumers. Unlike industrial burners, domestic gas appliances generally have no or minimal control of fuel to air ratio and rely on burner design and installation settings to perform over a wide turn-down range. Hence a key issue is to determine what design changes may be required to produce stable flames with a range of hydrogen concentrations. A second issue to address is whether burners may experience higher temperatures or localised hotspots which could lead to premature failure.

Domestic appliances use mainly pre-mixed or partially pre-mixed burners. Pre-mixed burners produce small blue flames by entraining all the required combustion air into the high velocity fuel jet(s) before the mixture leaves the burner via nozzles or mesh. Partially pre-mixed burners entrain some of the required air before leaving the burner, with the remainder entrained downstream. Adding hydrogen alters the density and entrainment potential of the gas jet in addition to the stoichiometric air requirement. Hence there is potential for incorrect fuel/air mixing ratios.

The Wobbe Index is the main parameter used when specifying suitability of gas for particular burner designs. The addition of hydrogen in particular produces more stable flames because it has a higher flame speed and wider flammability limits than methane. For lean premixed burners, the lean blow-off limit is extended when adding hydrogen to natural gas[42]. Flash-back becomes a greater risk for larger additions of hydrogen in blends, due to increased flame speed. However for additions up to 30%, the increase in flame speed is small. In contrast, the flame speed approximately doubles when adding 50% hydrogen and increases five-fold for pure hydrogen[43]. Flame speed is also dependent on the fuel/air ratio in the mixture, reducing as the mixture becomes more fuel lean. Current lean premixed burners naturally operate at more lean conditions when hydrogen is blended into the gas. This means that practically no flash-back is likely to occur even for blends with up to 50% hydrogen[44].

European standards have been developed to test interchangeability of gases for domestic appliances. These are short term tests of appliances with different gases and gas blends. Current European domestic gas appliances are routinely tested with a mixture of 23% hydrogen and 77% natural gas (known as G222 test gas) with no problems.[45] These findings suggest that, for pre-mixed burners in appliances such as ovens, stove tops, water heaters and space heaters, blends of up 23% and most likely up to 30% in natural gas can be accommodated by existing burners or existing burners with minor modifications.

In some cases it may also be necessary to slightly increase the final regulated pressure at the entrance to customer premises to allow higher gas velocities in the burner ports. The main costs likely to be incurred by manufacturers will relate to testing and regulatory work at all levels of hydrogen addition. The likely requirements at different levels of hydrogen addition are shown in the table below.

[42] (Schefer 2006)
[43] (Ilbas et al 2006)
[44] (De Vries et al 2007)
[45] (Altfield and Pinchbeck 2013)

Table 4: Likely domestic burner changes with increasing % hydrogen in natural gas.[46]

Hydrogen % vol in NG	Domestic pre-mixed burner requirements
2 –5%	No change to current design and practice.
5 –10%	No design changes expected. However, full testing of current burners for stability, turndown and flashback, and of materials response to altered heat loading is required. New regulations to be established and met.
10 –30%	Burners to be tested and design changes may be required in some cases to avoid flash-back. New regulations to be established and met.

4.2. Industrial furnaces, process heaters and boilers

Industrial non-premixed burners used to produce radiant flames in boilers and kilns use burner momentum to entrain combustion air. These burners are designed to handle fuel changes by adjusting gas and primary air momentum. Addition of small amounts of hydrogen to natural gas will slightly reduce flame radiation, and will require adjustments to burner operation to achieve a similar heat flux profile to the process. Burner designs should be checked for fuel changes of more than 5%, but in some cases it may not be necessary to make any changes for up to 30% hydrogen addition, because gas and primary air pressures can be adjusted to improve flame stability and compensate for reduced flame radiation. In other cases it will important to redesign burners to reduce mixing rates between air and fuel to promote flame radiation.

4.3. Gas turbine burners

Current generation of gas turbine burners used for power generation use lean pre-mix combustion methods to reduce NOx emissions substantially. The fuel and air are premixed to a lean composition and injected into a combustor. Because of pre-mixing there is the potential for flash-back and combustion driven pulsations. These problems have rarely arisen because natural gas has been supplied at a stable composition near the middle of the allowable Wobbe Index range, and with predictable stoichiometric air requirement. Turbines can be re-tuned for different gas mixtures to provide stable cold start-up, good combustion efficiency and to prevent flash-back, flame-outs and vibrations. A maximum hydrogen content of 1% is normally specified for gas turbines, but 5-10% may be possible with re-tuning. However, a larger issue is variability in gas composition. If the hydrogen content varies, then on-line tuning of the gas to air ratio is required. The implications for variable rates of hydrogen injection at concentrations above 1% is that each turbine will need to be assessed and measures taken, such as redesign of combustors, or improving control systems to include on-line composition measurement and control or fuel heating.

Manufacturers of turbines such as General Electric[47] and Alstom[48] have developed more rapid composition measurement than PGCs for online combustor control[49] via calculation of Wobbe Index, and have developed new burner designs with higher injection velocities or other methods to avoid flashback issues. Siemens[50] have used combustor exit temperature control of fuel and air ratio for turbines that can handle variable fuel composition. These various turbine control strategies can allow use of natural gas blends with hydrogen content up to 30% and higher. It should also be noted that turbine combustors are already in use for refinery tail gas with compositions of around 50% hydrogen.

4.4. Gas engines

Gas engines, such as those used in vehicles and some stationary combined heat and power units are sensitive to gas mixture concentrations. Knocking can occur if the engine is not tuned

[46] Adapted from Melaina et al (2013)
[47] (Jones et al 2011)
[48] (Knapp et al 2012)
[49] (Abbott et al 2012)
[50] (Blomstedt et al 2017)

to the fuel. Natural gases already have a range of methane numbers, which describes the knocking behaviour of the fuel. Pure methane has a methane number of 100, and addition of either higher hydrocarbons or hydrogen reduces the methane number and can lead to knocking. Addition of 10% hydrogen produces a smaller change than the current range of methane numbers in various natural gases. However if hydrogen is added to a natural gas that already has a low methane number, it can cause knocking. The increase in flame speed with hydrogen addition will increase cylinder peak pressure which may have an effect on performance and life. Some recommendations for use of 2%-5% hydrogen in natural gas engines have been made, but case by case implementation and testing may be required, due to the variability of natural gas composition, engine design and loss of performance with age. As with gas turbines, variability of the hydrogen concentration is a potential problem, with the need for on-board tuning based on NOx emissions or some other method.[51]

4.5. CNG stationary and on-board storage vessels

Research is being conducted in Europe to investigate how to increase the permissible hydrogen content used in CNG vessels, currently limited to 2%, if the cylinder steel has an ultimate tensile strength exceeding 950 MPa (138 kpsi). The limitation of 2% is set to avoid hydrogen embrittlement in these high strength steels. As a result, if more hydrogen were to be used, the steel grades may have to be changed. However any changes will take a long time to implement because the current fleet of vehicle tanks will have a lifetime of 20 years.

4.6. Life cycle cost implications

The life-cycle cost implications for addition of up to 30% hydrogen to natural gas for costumer materials and plant equipment are likely to relate to:

- Costs incurred by domestic appliance manufacturers for testing and regulatory compliance at all levels of hydrogen addition from 5% upwards to determine whether burner designs need to be changed to prevent overheating and premature failure or damage.
- Industrial burner redesign on a case by case basis at hydrogen concentrations above 5%, although in many cases existing burners will be able to continue to be used with changes to operation.
- Gas turbine combustor and gas engine re-tuning, and use of control systems to allow for gas composition variation for hydrogen compositions above 1%.
- CNG vessel testing and replacement for hydrogen compositions above 2%.
- As part of any gas selling or third party arrangement, an assessment of consumer burner equipment will need to be made. Where burner equipment is deemed to be unsuitable as the concentration of hydrogen increases, replacement of these items will need to be scheduled before blend quality is due to change.

4.7. Gaps in knowledge

The changes required for different additions of hydrogen will all incur costs, which will need to be more accurately estimated for each type of customer and plant as part of the planning process. The information presented in this chapter provides a good starting point.

4.8. Summary of impacts on plant equipment

In some sectors there will be few issues with addition of hydrogen into natural gas, but in other sectors, there would need to be considerable work to reach an understanding of the modifications required to equipment and the limits to gas composition. The summary table below provides a checklist of customer plant equipment issues that will need to be taken into account when considering injecting renewable gas into gas networks.

[51] (Altfield and Pinchbeck, 2013)

Table 5: Summary of issues related to customer material / plant equipment that need to be taken into account when considering injecting hydrogen into gas networks.

Customer equipment	Issues
Domestic appliances	No issues likely for hydrogen addition up to 30%. However, slight modification may be required.
Industrial pre-mix burners	No issues likely for hydrogen addition up to 30%. However, slight modification may be required.
Non-premix burners for boilers and kilns	Burners may need to be modified with hydrogen addition above 5% and need assessment on a case by case basis
Gas turbine burners and engines	Ongoing development required to allow increase in hydrogen content and variability in gas composition
CNG stationary and on-board vessels	Issues with steel grades with hydrogen addition above 2% and fleet lifetime need to be addressed.

5. COMMERCIAL ASPECTS

This section highlights the main issues related to determining gas composition, heating value, flow-rate and losses, which will need to be addressed if renewable gas is mixed into a gas distribution network.

5.1. Heating value and gas composition

The Higher Heating Value (HHV) of natural gas varies depending on composition. Methane has a HHV of 37.7 MJ/m^3, based on standard conditions (101.325 kPa and 15^{o}C). Typical values for natural gas vary with composition, but are similar to that of methane because the increase in HHV caused by the presence of higher hydrocarbons is roughly balanced by the presence of inerts.

AS 4564-2011[52] specifies a maximum natural gas HHV of 42.3 MJ/m^3, with the allowance for short term excursions over this level. The maximum is set because high values are caused by increased concentrations of higher and more complex hydrocarbons which have greater sooting propensity than methane when combusted. Soot can cause blockages in finned heat exchangers or other equipment.

The effects of adding small amounts of hydrogen or SNG on the heating value of natural gas are relatively small. SNG is typically almost 100% methane, which has a HHV of approximately 38 MJ/m^3, but varies a little depending on composition, with higher amounts of ethane, propane and higher hydrocarbons balancing out reductions in heating value due to the small amount of inerts (nitrogen and carbon dioxide). Hence adding SNG to natural gas has negligible effect on heating value.

Hydrogen has a HHV of 141.8 MJ/kg, or 12.09 MJ/m^3. Adding hydrogen to natural gas will reduce the density and the volumetric HHV of the gas, meaning a larger volume of gas will be required to supply the same total heat. For example, if natural gas with a HHV or 38.3 MJ/m^3 or 51.1 MJ/kg has hydrogen added to bring the composition to 30% hydrogen by volume, the HHV will change to a lower value on a volumetric basis, i.e. 30.4 MJ/m^3 (but to a higher value on a mass basis, i.e. 55.3 MJ/kg), as detailed in the table below. Figure 1 illustrates the variation in HHV with addition of hydrogen, on volumetric and mass bases.

Table 6: Standard density, volumetric HHV and gravimetric HHV for natural gas, hydrogen and hydrogen / natural gas blend.

	Standard density (kg/m^3) at 15^{o}C and 1 atmosphere	Volumetric HHV (MJ/m^3)	Gravimetric HHV (MJ/kg)
Natural gas	0.75	38.2	51.1
Hydrogen	0.085	12.1	141.8
30% H_2 / 70% NG (vol basis)	0.55	30.4	55.3

[52] AS 4564-2011 - Specification for general purpose natural gas.

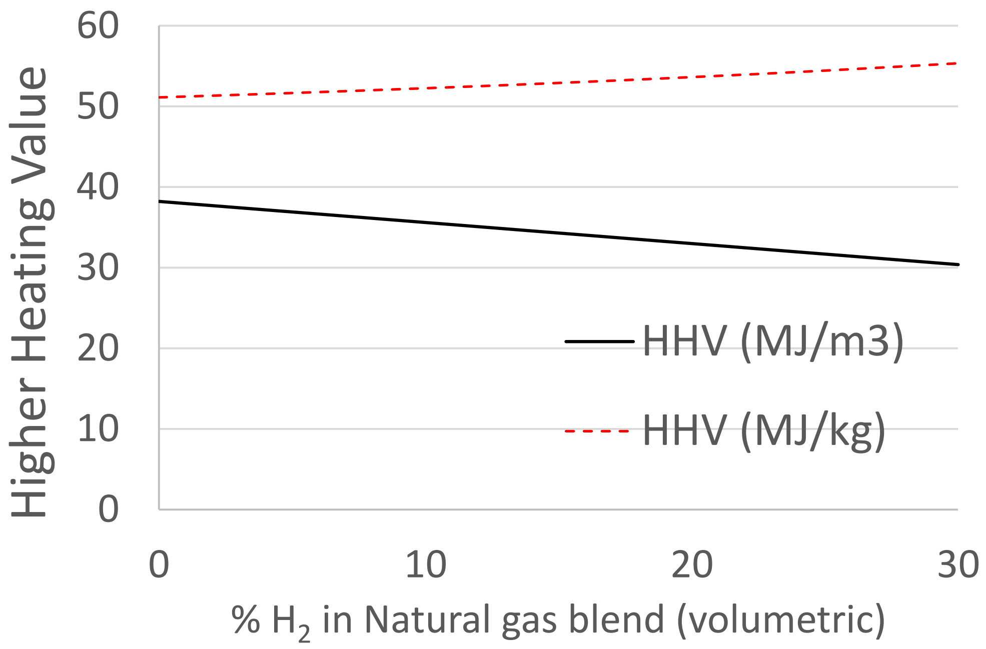

Figure 1: Effect of hydrogen addition on Higher Heating Value of natural gas.

Figure 2Figure 2 shows the relationship between mass and volumetric hydrogen content of hydrogen / natural gas blends up to 30% hydrogen by volume. Thirty percent hydrogen on a volume basis is only 4.7% hydrogen on a mass basis. To deliver the same amount of energy as 1m^3 of natural gas, 1.26m^3 of 30%(vol) H_2/NG would be required, of which 0.38 m^3 is hydrogen and 0.88 m^3 is natural gas, as illustrated in Figure 3. It shows the total volume of gas, and the volume of hydrogen and natural gas required to replace the energy value of 1m^3 of natural gas. The implication is that higher volumes of gas will be required to provide the same amount of energy, and this may require additional compressors. Depending on the concentration of hydrogen, modification to equipment may also be required.

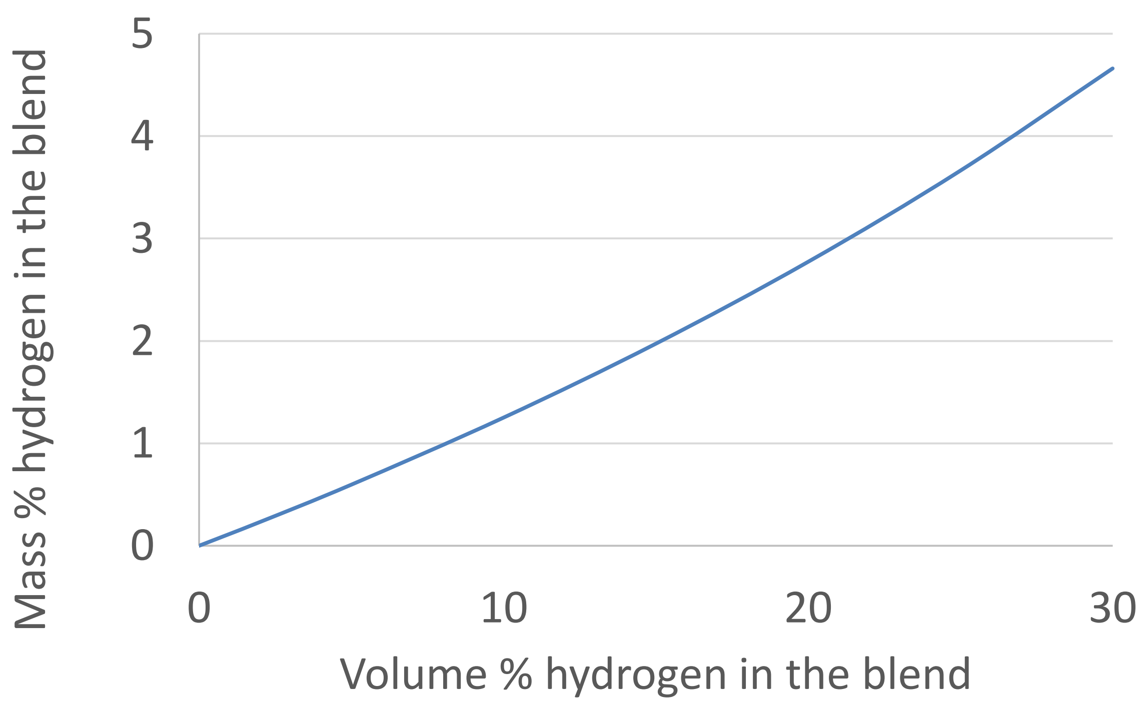

Figure 2: Relationship between volumetric and mass % hydrogen.

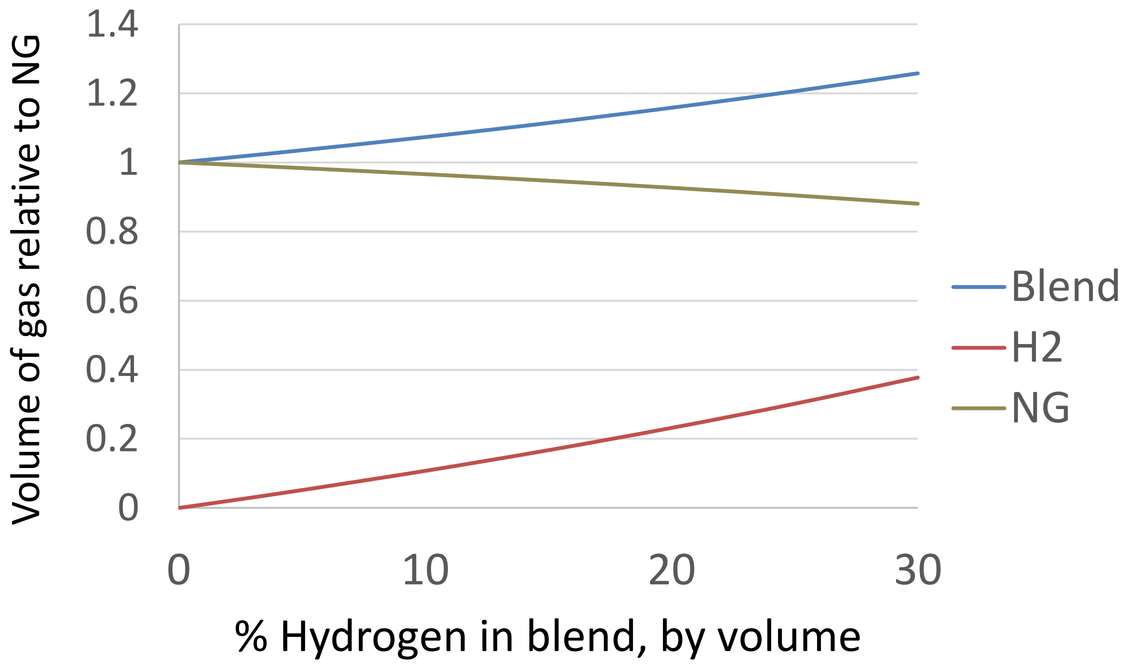

Figure 3: Equivalent energy content for blends of hydrogen / nature gas.

5.2. Greenhouse gas emissions

An implication from Figure 2 and Figure 3 is that the reduction in natural gas usage, and the maximum greenhouse gas emission reduction with the introduction of 30% by volume hydrogen would be 12%, if the hydrogen was produced and transported with no emissions. Figure 4 plots this more explicitly. Figure 5 extends the plot to additions of up to 100% hydrogen. At 50% hydrogen by volume, GHG emissions reduction is up to 25%. The exponential increase in emission reduction with increase in hydrogen to 100% is due to the lower volumetric energy density of hydrogen. In fact, to deliver equal energy content, over three times the volume of hydrogen is required as natural gas.

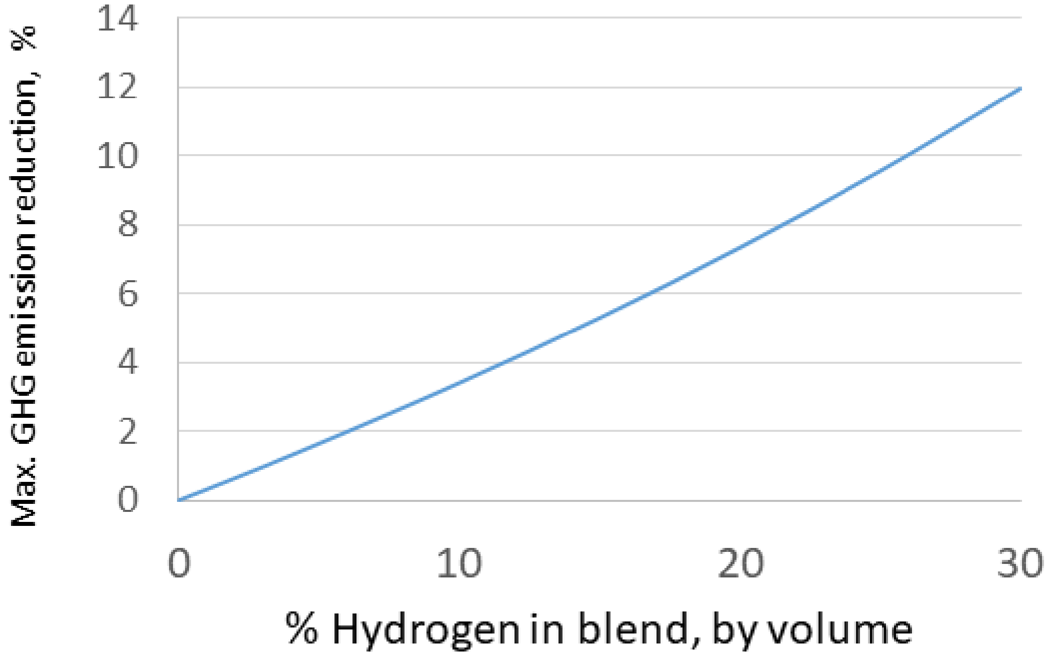

Figure 4: Maximum GHG reduction with hydrogen addition up to 30% by volume.

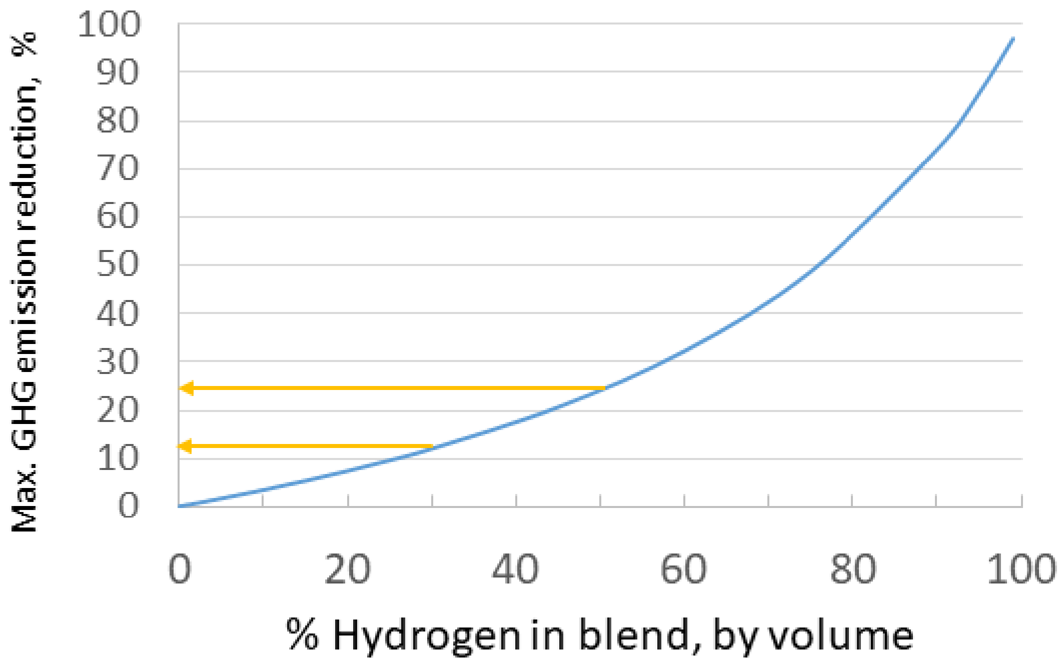

Figure 5: Maximum GHG reduction from blending hydrogen into natural gas at different volume %.

5.3. Wobbe Index

The Wobbe Index is equal to the Higher Heating Value (HHV) divided by the square root of gas specific gravity. Gases of the same Wobbe Number are interchangeable to the extent that they will produce the same heat release when supplied through the same nozzle at equal pressure. Australian natural gas specifications call for a Wobbe Index between 46.0 and 52.0 MJ/standard cubic metre [53]. If the Wobbe Index is too high it can cause overheating or high carbon monoxide emissions, or if too low, it can cause flame instability or flash-back.

Consider a typical natural gas with a composition of methane 91.25%, ethane 4.53%, propane 0.54%, butane 0.28%, nitrogen 1.4% and carbon dioxide 2%. This composition has a Wobbe Index of 48.9 MJ/m^3, i.e. in the middle of the allowable range. Adding any amount of hydrogen causes a reduction in Wobbe Index, addition of 10% hydrogen reduces the Wobbe Index by 3%, but adding 25% hydrogen will cause a reduction in Wobbe Index below 46 MJ/m^{3}as illustrated in Figure 6.

Consider a leaner natural gas that has minimal higher hydrocarbons, and more inerts, resulting in a low Wobbe Index of 47.0 MJ/m^3 before addition of Hydrogen. In this case, less than 10% hydrogen can be added before the Wobbe Index drops below 46 MJ/m^3. Figure 6 also illustrates that up to 44% hydrogen by volume could be added to a very rich natural gas with an initial Wobbe Index of 52 MJ/m^3 before the Wobbe Index was reduced to 46 MJ/m^3.

[53] AS 4564-2011 Specification for general purpose natural gas.

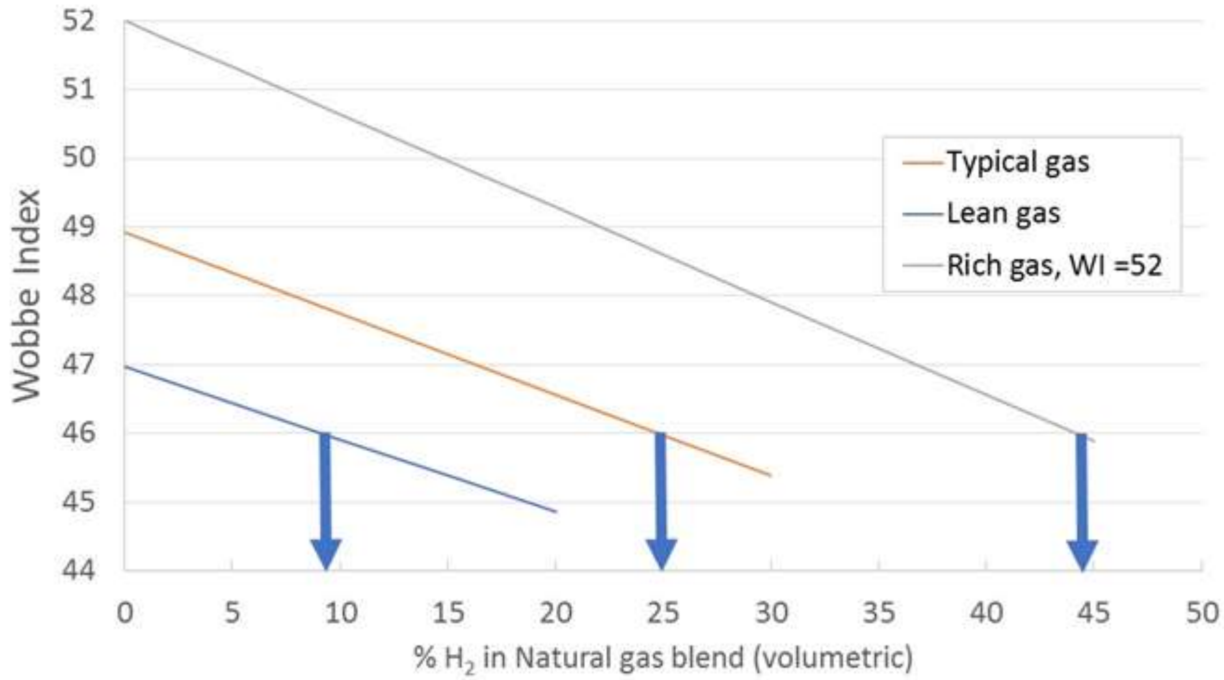

Figure 6: Effect of adding hydrogen to typical natural gas with an initial Wobbe Index of 48.9, and a leaner gas with Wobbe Index of 47.0.

5.4. Flow rate and pressure drop

Adding hydrogen reduces the density of natural gas, and increases the required volumetric flow-rate to achieve the same rate of energy delivery. Consequently, velocity and pressure drop in distribution pipelines also increase for the same energy delivery. An illustration for a low-pressure part of the distribution system, operating at an inlet pressure of approximately 40 kPa (g) is shown in Figure 7. It shows the pressure drop in a 100m length of 25 mm nominal diameter steel pipe delivering 0.5 MJ/s of gas with an exit pressure of 10 kPa(g). In this case, there is an additional pressure loss of 5 kPa when 30% hydrogen is added compared to the case with no hydrogen. In cases where delivery rates are already tightly constrained, such changes need to be considered. This is an illustrative example; each case will be different.

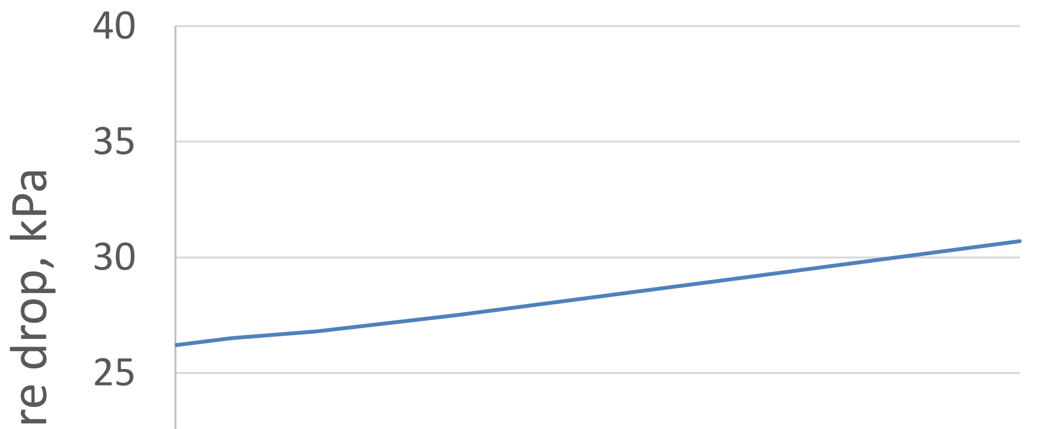

Figure 7: Example of pressure drop dependence on hydrogen content of natural gas.

5.5. Measurement of gas composition, flow-rate and unaccounted gas

Accurate measurement of composition and flow-rate are required for gas pricing. In plants and gas distribution systems, heating value and composition can both be determined by process gas chromatographs (PCGs). Those PCGs which use helium as a carrier gas are not able to measure hydrogen and will need to be modified or replaced by new models which use Argon as a carrier gas, thereby incurring additional costs. Some manufacturers have already produced PCGs capable of measuring natural gas containing up to 10% hydrogen[54], so it can be expected that instruments will become readily available to measure concentrations up to 30% hydrogen.

Calculation of mass flow from volumetric meters, e.g. turbine meters, relies on measured pressure and temperature, but typically use an assumed value for gas molecular weight. For such meters, accuracy becomes less certain with increasing hydrogen concentration, especially at hydrogen concentrations above 10%.[55] As a consequence, there is scope for measurement errors if the amount of hydrogen in natural gas is variable. However, calibrations can be made if the new gas composition is known and doesn't vary significantly. Variability in composition will require adoption of mass flow meters or use of updated PCGs to measure composition and perform on-line flow-meter calibration.

Addition of hydrogen up to 30% is unlikely to significantly increase losses due to leakage. Various projects have tested leakage rates with 10% and 20% hydrogen in natural gas and found economically insignificant levels of leakage[56]. Leakage rates at 30% hydrogen are likely to increase slightly, but still be insignificant (see section 3.1).[57] Towns gas, used historically in many places, and still in Hong Kong, has approximately 50% hydrogen in the system.

5.6. Hydrogen injection locations

The locations, flow-rates and variability in flow-rate of hydrogen injection will influence the composition of blended gas throughout distribution networks. This is an issue that will require planning and modelling on a case by case basis. It may be necessary to use hydrogen storage tanks or pipelines to buffer injection rates if hydrogen supply is intermittent, and likewise it may be necessary to locate injection points at pressure let-down stations, and multiple other locations, to prevent wide variation in hydrogen concentration throughout the network.

5.7. Life cycle cost implications

The following aspects are necessary to consider when determining indicative life-cycle costs:

- Network costs to minimise variability in hydrogen supply, potentially including isolation of hydrogen supply from users who are more sensitive to hydrogen addition or to variability in composition.
- Process gas chromatographs (PCGs) will need to be modified or replaced to verify that specifications are met for gas composition, HHV and Wobbe Index. Flow measurement instrumentation will also need to be updated or calibrated. Operators and regulators will need to assess the minimum amount of hydrogen that can be added without updating instrumentation. Consumers may incur additional composition measurement and flow metering costs to cover changes in gas volume and heating value.
- At addition of up to 10% hydrogen, the Wobbe Index and heating value are likely to be within current limits, depending on the composition of the natural gas. Hence up to approximately 10% hydrogen addition can occur without hydrogen storage. However, it may be necessary to de-bottle-neck some sections of the network to maintain or improve energy delivery rates.

[54] (Altfield and Pinchbeck 2013)
[55] (Emerson 2005)
[56] (Melanina 2013
[57] (Melanina 2013)

- At hydrogen addition rates above 10%, it will be necessary to choose additional injection locations and to control rates, and add some hydrogen storage, depending on the intermittency of supply. These considerations will become more significant at addition rates of 20% to 30%. Likewise, depending on the condition of existing seals and joints, some replacements may be necessary to limit leakage.

5.8. Gaps in knowledge

Network operators will need to assess their gas distribution systems for potential physical bottlenecks that limit flow-rate, given that hydrogen addition increases volumetric flow-rates and pressure drop for the same energy delivery rate. There may be many changes required, the full extent of which will require further detailed investigation of the specific network under consideration.

Bottlenecks in the approval process and physical implementation of hydrogen injection into networks can be managed by planning. For example, detailed studies of the effect of injection locations and variability of injection rates on gas composition in specific networks will need to be performed to gain a fuller appreciation of the costs of transport, metering and storage required.

5.9. Summary of commercial issues

The table below contains a checklist of commercial issues that need to be taken into account when injecting renewable gas into gas networks.

Table 7: Summary of commercial issues that need to be taken into account when considering injecting renewable gas into gas networks.

Commercial issues	Issues
Heating value and Wobbe Index	Addition of SNG or biogas to natural gas will have little effect on heating value and Wobbe Index, but addition of hydrogen will. For example, addition of 10% hydrogen by volume lowers the heating value of natural gas by 6.6%.
Composition	Determination of gas composition by process gas chromatographs will require some modifications or new instruments and incur associated costs.
Metering of gas	Turbine flow-meters can be re-tuned to a new input gas density, but if the gas composition varies considerably, the density will too. Mass flow meters can be added at additional cost.
Mixing of injected gas within pipelines	The issue is how to distribute hydrogen evenly in the network if it is injected in a limited number of places.

6. REGULATORY AND STATUTORY ASPECTS

Two main considerations exist regarding regulations and state and code compliance when introducing renewable gases into gas distribution networks:

1. Compliance with relevant Australian Standards, and the state Acts and Regulations which detail supply, safety and acceptance levels.
2. Compliance with any Third Party Access requirements as set out for the particular gas network under consideration. The National Gas Laws and Natural Gas Regulations apply to various distribution networks and transmissions pipelines based on their competition classification.

These considerations will be further detailed in the sections below.

6.1. Australian standards

The main Australian Standards applicable to gas distribution and transmission systems are:

- AS 4564 – Specification for Natural Gas
- AS/NZS 4645 Series – Gas Distribution Networks – Parts 1, 2, and 3
- AS/NZS 5601 Series – Gas Installations – Parts 1 and 2
- AS 3814 – Industrial and Commercial Gas-Fired Appliances
- AS2885 – Pipelines – Gas and Liquid Petroleum

The relationship between some of these standards is depicted in Appendix A.

According to the scope of AS 4564:

This Standard sets out requirements for the safe composition, transportation and supply of general purpose natural gas for use in natural gas appliances and equipment, and for use as fuel in natural gas vehicles.

The standard details the applications in which it can be used, legislative and contractual variations, and objectives which tend to be detailed further in State regulations covering safety, quality, and security of supply.

AS 4564 sets out the limits of gas distributed as natural gas. Gas may contain variations on components which meet upper and lower criteria when used for combustion use. Heating value and residue limits apply, and contaminants are not allowed. It should be noted that the latest update of this Standard proposes to limit hydrogen in networks to 15%.

Gas in distribution networks must be suitable for the gas appliances by downstream consumers. Natural gas alternatives may not be suitable for industrial use where gas is used as a chemical feedstock (eg ammonia, sodium cyanide, gas to liquids, various petro-chemical applications).

The purpose of the AS/NZS 4645 set of standards (from the Preface in AS/NZS 4546.1) is:

a) provide performance-based requirements for gas distribution network safety, defining important principles during the life cycle of gas distribution networks;
b) provide prescriptive, deemed to comply, means of compliance in support of some of those requirements; and
c) *allow for alternative means of compliance that may be also acceptable provided the required safety outcomes can be demonstrated.*

The Scope defines that the AS/NZS 4645 series is applicable to networks operating at less than or equal to 1050 kPa. Part 1 covers the requirements for network management (including reference to related standards for Safety, Risk, etc). Part 2 is applicable to metallic networks, and Part 3 applies to non-metallic (plastic) networks.

The AS/NZS 5601 series replaced the previous gas installation code, AG 601, in 2000. Its application to gas installations tends to be more focussed on above-ground piping; however there may be some areas where it and AS/NZS 4645 series complement each other. AS/NZS 5601 is applicable to systems operating above 1050 kPa where the installation may be connected to a gas transmission network. AS/NZS 5601 is one standard used by various State gas regulators when inspecting, certifying, and or approving gas system designs and installations. Part 2 is not applicable to this study where it focuses on LPG installations for caravans and boats.

AS 3814 replaced AG 501 in 2009. Its applicability to gas fired appliances is worth considering based on the type of alternative fuel being delivered, and likely to be used in an environment where a flame, heat, light, power, etc are produced. It tends to be more focussed on commercial and industrial appliances, however it is worth considering when planning alternative gas injection into a supply network. The initial scope paragraph covers the standard’s intent:

This Standard provides minimum requirements for the design, construction and safe operation of Type B appliances that use any gas as a gaseous fuel to produce flame, heat, light, power or special atmosphere in any combination of these gases either together or with other fuels.

Note that there are a large number of Standards for various appliances and components. An overview of these standards is provided by SAI Global[58].

The AS2885 Pipelines - Gas and liquid petroleum specifies requirements for pipelines, including materials, design, construction, installation, inspection, testing, operating, and maintenance. It provides for single and multiphase hydrocarbons at operating pressure above 1050 kPa, or for interconnecting lines above 2000 kPa, and above 20 percent specified minimum yield within the operating range of -30 degrees Celsius to 200 degrees Celsius. The standard covers pipelines from wellhead assembly outlet to inlet valve of collection manifold, and includes submarine pipelines.

6.2. State Acts and regulations

For this study Tasmania and Northern Territory have not been considered due to the relatively small size of their gas distribution markets.

Queensland

The most applicable regulations for gas distribution in Queensland are

- QLD Gas Supply Act 2003
- QLD Gas Supply Regulations 2007
- Gas Pipelines Access Act (Qld) 1998
- Qld Natural Gas Qld Act 2008

The short description of the Queensland Gas Supply Act is:

An Act about the transport and supply of processed natural gas, and for other purposes.

The Act applies to both transmission and distribution systems, however regulation to transmission systems is not specifically covered. The Act refers management to the Queensland Competition Authority (QCA) along with the licensed Distributors and/or retailers. The regulations are more applicable to the ways in which the QCA manages distribution networks, and how changes may be proposed.

[58] (SAI Global 2017)

The Queensland Natural Gas Act 2008 replaced the Gas Pipelines Access Act 1998, and covers the general requirements of the National Gas Laws and National Gas Regulations regarding third party gas pipeline access.

New South Wales
The most applicable regulations for gas distribution in NSW are:

- NSW Gas Supply Act 1996 – 38
- NSW Gas Supply (Natural Gas Retail) Regulation 2014
- NSW Gas Supply (Safety and Network Management) Regulation 2013
- National Gas (New South Wales) Act 2008 No 31

The NSW regulations are similar to Queensland in that the main Act is very comprehensive, the Regulations are not as detailed as the Act, and Regulations are based on National Gas Laws and Regulations covering third party access.

NSW also includes a specific Gas Network Safety regulation which complements the applicable Australian Standards described previously.

Victoria
Victoria has a more complex regulation structure than other states in which different parties maintain authority of gas supply and distribution, and network management.

The applicable Victorian regulations are:

- National Gas (Victoria) Act - 2008
- Gas Pipelines Access (Victoria) Act – 1998
- Gas Industry Act Victoria – 2001
- Gas Safety Act – 1997
- Energy Safe Victoria Act – 2005

The National Gas (Victoria) Act follows the National Gas Act and Regulations for third party access to natural gas supply systems – it is a later revision to the 1998 Act. Victoria has perhaps the most complex natural gas transmission and reticulation systems in Australia, and third party access plays a big role in commercial regulation.

The Gas Industry Act regulates the gas industry in Victoria, and applies to the various supply and distribution entities. The Gas Safety Act complements the requirements are the applicable Australian Standards, and details the responsibilities of the gas companies with respect to safety, updating of safety systems, safety case analyses, etc.

The Energy Safe Victoria Act details the responsibilities of Energy Safe Victoria with respect to electricity and gas supply / reticulation.

South Australia
South Australia has its own Gas Act and Regulations along with following the National Gas Law Act and National Gas Regulations. The regulations specific to South Australia are:

- South Australian Gas Act – 1997
- South Australia Gas Regulations - 2012
- National Gas (South Australia) Law AER Amendment Act – 2009
- National Gas (South Australia) Regulations – 2013

The Gas Act states that it is: *An Act to regulate the gas supply industry; to make provision for safety and technical standards for gas infrastructure, installations and fitting work; to repeal the Gas Act 1988; and for other purposes*

The Regulations cover gas entities roles and responsibilities, along with Safety and Quality requirements. There are companion documents on the South Australian web site covering gas regulations which cover safety, efficiency, and applicable Australian standards.

The Natural Gas documents detail the roles that the Australian Energy Market Operator (AEMO), and the Australian Energy Regulator (AER) have which affect the various commercial markets in South Australia. This includes third party access and the short-term trading market.

<u>*Western Australia*</u>
Western Australia uses a complex set of Acts and Regulations to regulate their transmission and distribution networks. As with other states, they use the National Gas Laws Act and Regulations with respect to third party access opening relevant gas networks and pipelines to more competition. The key and relevant documents likely to be used are:

- Gas Standards Act – 1972
- Gas Supply (Gas Quality Specifications) Act - 2009
- Gas Services Information Act – 2012
- Gas Services Information Regulations – 2012
- Gas Distribution Regulations 1996
- Gas Standards (Gas Supply and System Safety) Regulations – 2000
- Gas Standards (Gasfitting and Consumer Gas Installations) Regulations – 1999

The long title of the Gas Standards Act is:

An Act to regulate the standards of quality, pressure, purity and safety of gas supplied and the standards and safety of gas installations and gas appliances; to provide for the supervision and control of persons concerned in, and to regulate the practice of, gasfitting; to repeal the Gas (Standards) Act 1947, and for incidental and other purposes.

The Acts and Regulations are slightly different to other states with Acts and Regulations tending to “share” details. The same information, as required by current and new participants, is still there. The Western Australia Regulator maintains an active involvement in regulating the gas industry.

6.3. Gaps in industry codes and standards

Compliance with the listed Australian Standards should confirm whether the alternative gases can be injected, and whether material and components (valves) require replacement. Of key importance is to ensure leak-tight components – valve seals, etc – are not compromised.

Regulators across various states have varying levels of active involvement – some place the onus on the supplier and/or use authorised inspectors, whilst others maintain a high level of in-house activity / focus. These varying levels may require a new applicant to further explain what impacts the introduction of any new “suitable” gas may have on the network, customers’ supply and availability, and safety. The Acts and Regulations don’t specifically “ban” alternative gases, like hydrogen and biogas, which may provide suitable heating requirements, however more detail regarding metering, appliance suitability, isolation, separation of gases where required, may need to be provided before a license is granted.

Renewable gases, especially hydrogen, might only be suitable for heating purposes, rather than chemical feedstock purposes. Industrial consumers and process plants where gas is used as a feedstock may not accept the alternative gas and methods of separation and/or keeping pipelines separated may be required.

6.4. QA requirements

Additional sampling, metering or other QA requirements may be required to align calorific values to correctly totalize gas consumption. State regulation generally includes requirements and methods of metering to the various consumers. Revisions to metering may be fairly straight forward when downstream consumers are classified as retail. Where consumers are classified as Commercial or Industrial, their supply contract conditions may be more specific. In these cases, methods of metering, sampling, and guarantee of specific gas quality may need to be reviewed and agreed prior to the introduction of any alternative gas (see also section 5.5).

Natural gas reticulation requires the addition of an odourant to assist in leak detection. The use of alternative gases may require modifications to the type and amounts of odourant added. The ability to provide effective isolation for specific distribution branches may require analysis and detail (for the Regulator) to protect the consumer and general public.

6.5. National gas regulations and impacts on third party access

Apart from any technical, quality, and regulatory requirements, a key aspect of injecting renewable gases is to gain access to existing gas distribution network infrastructure. Since the late 1990's, most states have adopted the legislation developed to enable third party access to an existing distribution network as part of increasing competition.

The national gas laws and regulations developed have been adopted and written by each state to suit their own requirements. The regulations require that network (and gas pipeline) owners develop a set of access principles and tariffs to enable a third party to inject gas into a nominated distribution network.

Owners affected by these access requirements include:

- Jemena Gas Networks
- APA Group (Various states)
- ATCO Gas Australia
- Australian Gas Networks

Access information and principles are available for selected networks in Queensland, NSW, Victoria, South Australia, and Western Australia. (Selected transmission pipelines are also included in the access requirements, but these are not part of this study.)

These access requirements also have an effect on the Short Term Trading Market which may require additional consideration when determining when to inject renewable gases.

Third parties wishing to inject alternative gases will need to follow the processes set down by network owners to gain access, and agree on the tariff structure to be applied. Once this is confirmed, the network owner and third party will have to obtain regulatory approval to inject the alternative gas.

Should the party wishing to inject an alternative gas be a network owner, then the third party access process is not required.

6.6. Licensing issues for hydrogen injection

This section will discuss licensing requirements based on method and location of hydrogen manufacture, along with the method of transport, and how the hydrogen blend/s are injected into the gas network.

In this case a smaller gas network has been used as an example, i.e. Australian Capital Territory (ACT). The network operator is ActewAGL for most of the ACT gas distribution network. The network was previously owned by AGL, sold to Jemena, and ActewAGL formed. Gas is mostly supplied by APA, and regulations controlled by the Australian Energy Regulator (AER). AER have reviewed access submissions from ActewAGL, and access principles.

Once the method of transfer to the network injection point is established, then one of the following supply options applies:

- A supplier may choose to sell hydrogen to the gas network operator, and would incur costs for transport through the network, plus operations and maintenance. Smaller quantities may be more economical to sell directly to the network owner (refer discussion on hydrogen effects on heating value, equipment, etc chapter 5).
- A supplier may wish to operate as an independent third party supplier. In this case the applicable access arrangements for the network would apply, and tariffs would be negotiated with the network operator.
- For third party access, the supplier would make application using Schedules 2 and 3 of ActewAGL's current access arrangements.

Hydrogen manufacture may be subject to regulations such as Workplace, Health and Safety, Workcover etc. if the process does not rely on natural resources, and is located in an urban or semi-urban area – e.g. processes such as electrolysis, air separation / distillation, reforming. If the process plant relies on natural resources (e.g. mined gas, coal, etc.), and is located on a mining lease, then licensing may be required in accordance with the State's natural resources / mining legislation.

Transport to the injection point may then determine further licensing requirements. Small quantities of hydrogen may be stored in liquid form, transported by truck, and then vapourised into the gas network. This scenario would require licensing for storage and handling of dangerous goods, and transport licensing for same would be required.

For larger quantities of hydrogen, a dedicated pipeline may be more economical, and a pipeline license would then be required.

6.7. Summary of regulatory issues

The table below lists the main potential gaps in existing Acts and Regulations that will need to be addressed to update them to apply to injection of renewable gases into the natural gas network.

Table 8: Summary of regulatory issues that need to be taken into account when considering injecting renewable gas into gas networks.

Topic	Gaps in current Acts and Regulations
Materials selection	Update AS/NZS 4564 parts 1, 2, and 3 pertaining to steel, copper, and non-metallic pipelines for gas containing different concentrations of hydrogen. Note that the updated standard currently proposes to limit hydrogen in networks to 15%.
Metering	Quality assurance of metering and calculation of gas composition
Appliances / customer plant and equipment	Appropriate guidelines for suitability of different compositions for different types of appliances
Isolation procedures	Updated procedures for gas containing hydrogen
Odourant	Modifications to the type and amounts of odourant added
Gas for different purposes	Separation of gases to supply customers who use gas for heating with a different composition to those who require methane as a chemical feedstock.

7. RISK ASPECTS

Safety issues relate to explosion and flame radiation risks resulting from leaks or more significant failures of pipelines or equipment.

7.1. Public and worker safety

Safety issues from gas release rates from loss of containment issues with biogas and SNG, as well as up to 30% hydrogen in natural gas are similar to those for natural gas.

Blending hydrogen into natural gas slightly widens the flammability limits, which means that leaks are slightly more likely to ignite. The lower flammability limit of hydrogen is 4% in air at standard conditions, whereas methane is 5%. Hence blending hydrogen into natural gas does not alter the lower flammability limit (LFL) much. However, blending has a larger influence on the upper flammability limit, which is 75% for hydrogen and only 15% for methane. Using Le Chatelier's rule a mixture of 30% hydrogen in natural gas would have an upper flammability limit of roughly 20%.

Risks due to explosion or flame radiation increase slightly in proportion to the hydrogen concentration for locations near the leak, but reduce at greater distances.[59] This is because hydrogen addition widens the flammability limits and allows earlier and more intense combustion for natural gas / hydrogen blends, but also implies that conflagrations are slightly smaller than for natural gas flames. Flames from natural gas with 24% hydrogen were slightly shorter and produced slightly greater convective heat loading on objects within the flame.[60] Explosions of hydrogen / natural gas blends have slightly higher overpressure and hence could cause more damage, but only significantly more if over 50% hydrogen was in the blend.[61]

7.2. Leak detection

Leak detection instruments using semiconductors work well for both hydrogen and methane. If semiconductor devices are set to alarm to a percentage of the LFL for methane, e.g. 10% or 20% of the LFL, (i.e. 0.5% methane or 1% methane in air), then they will also work well for blends of hydrogen in methane because the sensors detect hydrogen.

For leak detection instruments that do not detect hydrogen such as flame ionisation sensors and differential, infrared laser, absorption spectroscopy instruments the alarm set point could be adjusted to a lower level of methane detection than is currently used, so that the instruments could still be used effectively for blends of up to 30% hydrogen in methane. For example, a 30% hydrogen / natural gas mixture has a LFL of 4.7% fuel, or 3.3% methane in air. Hence maintaining an alarm set point of 0.5% to 1% methane in air would still be appropriate, or the set point could be lowered if desired. Based on the findings above, current standards for safety should be reviewed for blends with up to 30% hydrogen, but the likelihood is that minimal changes will be required.

It is not expected that addition of up to 30% hydrogen to natural gas will affect ground-water systems or air quality in the event of a loss of containment scenario because it would be a localised effect.

7.3. Environmental aspects

It is not expected that addition of up to 30% hydrogen or SNG to natural gas will affect ground / ground-water systems or air quality in the event of a loss of containment scenario.

In general it should be noted that hydrogen is not a greenhouse gas and its direct use will result in GHG reductions (provided it is produced from emission free resources).

59 (Melaina 2013)
60 (Lowesmith et al 2012
61 (Melanina 2013

7.4. Life cycle cost implications

Costs will mainly be associated with research, testing and approval. It may also be desirable to invest in new leak detection instruments that are capable of measuring hydrogen in addition to methane. This will certainly be required for hydrogen injection sites and locations in the hydrogen generation and supply network.

7.5. Gaps in knowledge

Safety issues for the pipeline transport of hydrogen / natural gas blends have been covered here, but safety considerations need to be extended to include hydrogen generation, transmission, storage, and injection locations for pure hydrogen.

7.6. Summary of risk issues

A summary table / checklist of risk issues that need to be taken into account when injecting renewable gas into natural gas networks follows:

Table 9: Summary of risk issues that need to be taken into account when considering injecting renewable gas, in particular hydrogen, into gas networks.

Risk	Issues
Loss of containment inside buildings etc	Explosion risk – slightly more severe.
Loss of containment from pipelines, distribution lines	Fire radiation slightly more severe near leak, less severe at distance.
Set point for alarms based on % of LFL	Review required, but likely to recommend no change for up to 15% hydrogen.
Leak detection sensors	Many types do not detect hydrogen, but will still detect methane in the presence of hydrogen.

8. UPSTREAM ASPECTS

Upstream issues relate to the effect of renewable gas injection into existing transmission pipelines or flow lines or unused pipelines. LNG exports are also discussed.

8.1. Transmission pipelines

Natural gas transmission systems operate at pressures greater than 1050kPa and often up to 15MPa in Australia. This is a considerable increase on the operating pressure of both medium and low pressure distribution networks. The pipeline grades used in transmission pipes varies from grade B (low strength) to high strength X70. Grade X80 is used in transmission networks elsewhere in the world, and could be used in Australia, but has not been to date. In general, as expected, higher strength pipelines operate at higher pressure.

Combining higher operating pressure of transmission pipelines with high concentrations of hydrogen means that these transmission pipelines can be susceptible to hydrogen embrittlement of the steel and potentially hydrogen induced cracking. However, the susceptibility of the steel to hydrogen embrittlement, and therefore the acceptable level of hydrogen content, depends on the steel grade.

Researchers using a variety of tests to study the steel's elongation, fracture toughness, and fatigue crack growth rate, showed that higher strength linepipe, e.g. Grade X80, is susceptible to hydrogen embrittlement.[62] The result of tensile tests showed that while the X80's Young's Modulus, yield and tensile strength remained unchanged, its elongation decreased in a hydrogen environment. The reduction in elongation (ductility) increased as the hydrogen pressure increased up to 5MPa, and then remained constant at higher gaseous hydrogen pressures.

Testing of X80 in 30MPa hydrogen showed a marked decrease in the fracture toughness and increase in the fatigue crack growth rate for the steel compared to testing in air.[63] Other work on X80 linepipe steel[64] showed that the steel became susceptible to hydrogen cracking at hydrogen pressures above 0.1MPa and the extent of embrittlement, as measured by elongation, increased up to a pressure of 10MPa, after which it remained constant.

These findings confirm the need for caution when injecting significant levels of hydrogen into transmission pipelines, especially into higher grade pipelines operating at higher pressures. However, the evidence suggests that it should be possible to inject at least low levels of hydrogen into transmission pipelines without posing a significant risk to the pipeline, depending on the pipeline's strength and operating pressure.

The question of whether the gas is likely to impact the integrity of any part of the transmission pipeline including line pipe, valves, and compressors, requires consideration the following factors:

- The origin of the renewable gas, its injection location, and its transmission / transport from origin to injection point.
- The required transmission pressures and temperatures. Is the gas stable, safe, and capable of being transmitted under these conditions?
- Any additional fluids required to be injected.
- Requirement for early separation of the gas mixture before it gets to a specific location.
- Nature of the supply contracts that are in place. Do these prevent renewable gas being injected?

[62] (Briottet 2012)
[63] (Briottet 2012)
[64] (Moro 2010)

8.2. LNG export

LNG tends to be more focussed on gas composition and quality, and is unlikely to accept renewable gases, in particular hydrogen, into the supply system in the near term.

LNG suppliers have been focussed on achieving the gas composition and quality required by the large contracts signed with overseas markets. Local LNG producers have added in concerns over varying quality in LNG storage tanks causing roll-over.

Injection into LNG systems may be feasible when considering small LNG liquefaction plants coupled with road transport systems. Major LNG plants such as those operating in Queensland, Western Australia and Northern Territory are unlikely to consider these options.

8.3. Other upstream aspects

Injection of alternative gases into upstream systems may be feasible in areas where the alternative gases are local to the upstream source, and there is capacity within the existing infrastructure. An example of this would be where a supply pipeline is no longer in use, and is capable of bringing renewable gas closer to supply injection points. Sites around the Cooper Basin (Moomba) may present an opportunity. Flow lines feeding gas plants such as Moomba and Ballera may be able to bring in alternative gases for blending prior to introduction into major transmission pipelines – provided all criteria mentioned above are met.

8.4. Life cycle cost implications

Based on the above there is a need for caution when injecting significant levels of hydrogen into transmission pipelines, especially into higher grade pipelines operating at higher pressures. Combining higher operating pressure of transmission pipelines with high concentrations of hydrogen means that these transmission pipelines can be susceptible to hydrogen embrittlement of the steel and potentially hydrogen induced cracking. Mitigation options are discussed in section 3.2 and are likely to incur costs.

Lifecycle costs are discussed based on upstream considerations as process technology, location, method/s of transport, storage, and introduction into the gas distribution network. The costs of new pipelines and storage for dedicated hydrogen use need to be full costed. Such pipelines could be used to avoid introduction of significant amounts of hydrogen into high strength steel natural gas transmission pipelines and avoiding pressure cycling in transmission lines.

Costs associated with manufacturing, transport, storage and injection of hydrogen include:

- Costs of production of renewable gases like biogas, SNG and hydrogen. Costs are based on technology, location of feed-stocks, size of process plant, etc., and have been discussed in previous reports.[65]
- Compression and transport of hydrogen to the injection location/s. This includes operation of any truck / haulage fleet or pipeline if deemed to be the preferred method. The cost of transportation of hydrogen to the distribution network may be significant, given that renewable energy sources and locations for hydrogen production may be significant distances from distribution networks.
- Transmission costs by pipeline are based on the length and diameter of the pipeline and materials of construction. If the alternative gas is to be injected to a wide-scale network, then transport to major pressure reduction and metering stations may be appropriate. If transportation volumes are large enough to require steel pipelines, then a cost of $50/inch-diameter/metre length is still applicable in today's market. Compression budget costs are available from equipment suppliers. A cost of up to $5,000 per kW installed may be suitable for budgetary purposes.

[65] (Energy Pipelines CRC 2017)

- Storage of hydrogen at the injection location/s. This includes any tankage, and vapourisation equipment if hydrogen is transported in liquid form (note, tanks would be double-skinned with vacuum interface between outer and inner shells).
- Construction of above-ground facilities to control pressure, meter flow rate, and inject / blend into the natural gas network. Construction of a separate metering station next to an existing gate station is appropriate. Additional pipework will be required to blend the gases (eg using static mixers, etc). The gate station will contain metering and gas testing facilities required to confirm custody transfer amounts, costs. Costs of major metering stations vary based on complexity and gas demand. Costs may be estimated at $200,000 per TJ/day. The nature of the metering station will vary to accommodate variances in injection percentage. (Installed capital costs may vary from $5M to $10M based on systems required – pressure control, flow control, metering, SCADA control and communication, emergency response.
- Operation and maintenance cost, over and above the costs associated with handling natural gas.
- End of life costs, decommissioning.
- Potential costs associated with scaling up all systems to cope with market growth.
- For a new entrant, capital costs may be lower when injecting into an existing owner's network. Additional operating costs are applicable – tariffs applied by the owners along with any arrangements the owners and new entrant may make on operations, maintenance and inspection of the new facilities. Tariff structures are available from major network incumbents (Jemena, APA Group, ATCO Gas, AGN). There may well be situations where some of these activities are taken on by the network owner, and covered by tariffs.

8.5. Gaps in knowledge

There are gaps in knowledge regarding the costs of options for renewable gas, and in particular hydrogen transmission directly to the distribution network from the point where it is produced.

Refer previous sections in this report on technology, heating value, commercial / regulatory issues.

8.6. Summary of upstream issues

The following table summarised the upstream issues that need to be taken into account when injecting renewable gas into natural gas networks.

Table 10: Summary of upstream issues that need to be taken into account when considering injecting renewable gas into gas networks.

Upstream Aspects	Issues
Transmission pipelines	More susceptible to hydrogen cracking due to use of high strength steel and high operating pressures.
	Stability of renewable gas stable and its impact on downstream equipment.
	Potential need for separation of hydrogen from natural gas downstream.
	Preclusion of injection of renewable gas due to existing contractual arrangements.
LNG Export	Addition of hydrogen is not an option at this stage due to tight controls of gas specification, SNG would be possible.
Flow lines in gas fields or redundant pipelines	May provide the opportunity to bring renewable gases to gas plants or transmission lines.

9. SUMMARY OF TECHNICAL, COMMERCIAL, REGULATORY, SAFETY AND UPSTREAM ISSUES

The following table summarises the issues that need to be considered for injection of renewable gas into a natural gas network. Most of the issues listed focus specifically on the addition of hydrogen into the network.

Table 11: Summary of commercial, technical, appliance / equipment, regulatory, safety and upstream issues associated with injecting renewable gas, specifically hydrogen, into gas networks.

Area	Issues to address or note
Materials Performance	
Fatigue cracking in steel pipelines in hydrogen service	Limit pressure and pressure cycling
Hydrogen permeability	Assess for pipeline plastics and elastomeric materials used for seals and gaskets, etc.
Strength and mechanical properties of metallic pipes	Assess on a case by case basis, use lower strength steels for hydrogen duty (in combination with low pressures common in gas distribution systems).
Gas impurities	Assess on a case by case basis, for both ferrous and plastic pipe materials.
Appliances / Plant equipment	
Domestic appliances	No issues likely for hydrogen addition up to 30%. However, slight modification may be required.
Industrial pre-mix burners	No issues likely for hydrogen addition up to 30%. However, slight modification may be required.
Non-premix burners for boilers and kilns	Burners may need to be modified with hydrogen addition above 5% and need assessment on a case by case basis
Gas turbine burners and engines	Ongoing development required to allow increase in hydrogen content and variability in gas composition
CNG stationary and on-board vessels	Issues with steel grades with hydrogen addition above 2% and fleet lifetime need to be addressed.
Commercial	
Heating value and Wobbe Index	Addition of SNG or biogas to natural gas will have little effect on heating value and Wobbe Index, but addition of hydrogen will. For example, addition of 10% hydrogen by volume lowers the heating value of natural gas by 6.6%.
Composition	Determination of gas composition by process gas chromatographs will require some modifications or new instruments and incur associated costs.
Metering of gas	Turbine flow-meters can be re-tuned to a new input gas density, but if the gas composition varies considerably, the density will too. Mass flow meters can be added at additional cost.
Mixing of injected gas within pipelines	The issue is how to distribute hydrogen evenly in the network if it is injected in a limited number of places.
Regulation	
Regulations - Materials selection	Update AS/NZS 4564 parts 1, 2, and 3 pertaining to steel, copper, and non-metallic pipelines for gas containing different concentrations of hydrogen.
Regulations - Metering	Quality assurance of metering and calculation of gas composition.
Regulations - Appliances / customer plant and equipment	Appropriate guidelines for suitability of different compositions for different types of appliances.
Regulations - Isolation procedures	Updated procedures for gas containing hydrogen.

Regulations - Odourant	Modifications to the type and amounts of odourant added.
Regulations - Gas for different purposes	Separation of gases to supply customers who use gas for heating with a different composition to those who require methane as a chemical feedstock.
Safety	
Safety - Loss of containment inside buildings etc	Explosion risk – slightly more severe.
Safety - Loss of containment from pipelines, distribution lines	Fire radiation slightly more severe near leak, less severe at distance.
Safety - Set point for alarms based on % of LFL	Review required, but likely to recommend no change for up to 15% hydrogen.
Safety - Leak detection sensors	Many types do not detect hydrogen, but will still detect methane in the presence of hydrogen.
Upstream	
Transmission pipelines	More susceptible to hydrogen cracking due to use of high strength steel and high operating pressures.
	Stability of renewable gas stable and its impact on downstream equipment.
	Potential need for separation of hydrogen from natural gas downstream.
	Preclusion of injection of renewable gas due to existing contractual arrangements.
LNG Export	Addition of hydrogen is not an option at this stage due to tight controls of gas specification, SNG would be possible.
Flow lines in gas fields or redundant pipelines	May provide the opportunity to bring renewable gases to gas plants or transmission lines.

10. SUMMARY LIFE CYCLE COST IMPLICATIONS

A summary of all the life-cycle cost implications discussed in previous sections is provided below.

Cost associated with materials and joints in distribution networks

There are no significant issues with materials (steel, copper and plastic) and joints used in distribution networks for blends of up to 30% hydrogen in natural gas. Consequently, there are no direct materials costs, but there will probably be costs associated with monitoring and testing that may be required by both operators and regulating bodies. Furthermore, depending on the condition of existing seals, joints and sections of pipeline, some replacements may be necessary to minimise the potential for hydrogen leakage.

Costs for customers

A premium may be charged that reflects the extra costs incurred by network operators for hydrogen manufacture, transport, storage, blending and monitoring of composition and flow measurement. However, this cost maybe partially offset by a price on carbon or other policy instruments / market mechanisms.

Costs associated with assessments of consumer burner equipment and possible replacement or modifications to such equipment. Equipment modification will need to be scheduled before blend quality is due to be changed. This will be the case for domestic and industrial gas users.

Costs of assessing and potentially re-designing / re-supply of equipment will start to be incurred at different levels of hydrogen for different customers: for domestic appliances 5% upwards, industrial burners 5%, and gas turbine combustors 1%, CNG vessels 2%.

Cost associated with meeting commercial specifications

There will be costs associated with delivering gas within the specification limits for heating value, Wobbe Index, composition and ensuring accuracy of flow-rate monitoring. Hydrogen generation will probably by intermittent, so prior to addition of even small amounts of hydrogen, modelling will be useful to estimate concentrations throughout a network under different intermittent addition rates. Such modelling would allow calculation of the allowable rates of hydrogen addition before the need to update composition and flowrate instrumentation and/or introduction of hydrogen storage and/or hydrogen pipelines to provide multiple injection points.

It is expected that costs for updating PCGs and flow rate instrumentation will need to be incurred at low levels of hydrogen addition, in the region of 2% by volume.

The need for introduction of hydrogen storage vessels depends on the intermittency of supply and the inherent storage volume of the hydrogen supply pipelines. The required storage capacity is likely to be significant, and can be managed to some degree by adding hydrogen to sections of a network with the highest natural gas flow.

Network costs may also be incurred to isolate some customers from a blended gas supply.

Cost associated with risk and regulation

Regulatory lifecycle costs need to consider quality testing and assessment of quantity based on plant capacity and contractual delivery obligations.

Costs associated with risk management will mainly be associated with research, testing and approval. It may also be desirable to invest in new leak detection instruments that are capable of measuring hydrogen in addition to methane. This will certainly be required for hydrogen injection sites and locations in the hydrogen generation and supply network.

Costs associated with manufacturing, transport, storage and injection of renewable gas

There are a range of costs associated with the manufacturing, transport / transmission, storage and injection of renewable gas, in particular hydrogen, that need to be further studied, including:

- Costs of production of renewable hydrogen
- Compression and transport of hydrogen to the injection location/s
- Storage of hydrogen at the injection location/s
- Construction of metering and test stations for injection
- Operation and maintenance cost associated hydrogen manufacturing, transport and storage
- Costs associated with scaling up all systems to cope with market growth
- End of life costs, decommissioning
- Tariff structures and arrangements

11. GAPS IN KNOWLEDGE

The following gaps in knowledge have been identified in this study and need to be considered when injecting renewable gas into gas distribution networks:

- More comprehensive investigations of leakage rates of hydrogen from all types of plastic pipes in a range of locations and pressures is recommended as information from existing literature is limited in this area.
- New knowledge on long term performance of materials transporting and storing natural renewable gas is required, as the long-term performance of existing metallic and plastic pipe materials transporting renewable gas, in particular hydrogen methane blends, is not fully understood. New materials for transport and storage of renewable gas with improved performance characteristics and degradation resistance may also be developed.
- The mechanism of hydrogen embrittlement for high strength steel pipelines operating high pressures needs to be better understood to improve design of such pipelines by developing predictive models.
- Improved and validated thermodynamic models and associated design software for high and low pressure pipelines transporting natural gas and renewable gas mixtures.
- Impurities or containments in hydrogen, SNG, biogas or renewable / natural gas blends may affect network materials and costumer equipment and require further study.
- Assessment of distribution networks for physical bottlenecks that limit flow-rate given that hydrogen addition increases volumetric flow-rates and pressure drop for the same energy delivery rate.
- Bottlenecks in the approval and regulatory processes for hydrogen injection also need to be identified. Transfer of regulatory best practice in other jurisdictions to the Australian safety regulators is suggested to ensure safety risks linked to renewable gas will be effectively regulated.
- Detailed studies of the effect of injection locations and variability of injection rates on gas composition in specific networks will need to be performed to gain a fuller appreciation of the costs of transport, metering and required storage capacity
- The full extent of changes required to the instrumentation and customer equipment need to be understood on a case by case basis. The changes required to industrial and domestic burners and control systems has only partially been addressed in previous work and needs to be more comprehensively addressed in each case.
- Improved gas composition, flow metering, as well as leak detection instruments may need to be developed. Such equipment should be capable of handling hydrogen in addition to methane.
- Safety considerations need to be reviewed for hydrogen generation, transport and injection and more detailed risk assessments (including dispersion modelling) need to be considered.
- Lifecycle costs need to be assessed for hydrogen production, transmission, storage and injection and how these can be reduced. It is suggested to undertake process modelling and techno-economic analysis. Detailed modelling of the renewable gas production processes and supply chain; and subsequent identification of systems or components that provide the highest return on R&D investment.

12. CONCLUSIONS

Gas distribution systems consist mainly of plastic pipes, largely polyethylene, and a small amount of PVC. Polymer degradation under renewable gas service, including hydrogen, has not been found to be an issue. Contaminants in hydrogen, SNG, biogas or renewable / natural gas blends may affect plastics, but requires further study.

Leakage rates due to permeability of plastics to hydrogen are slightly higher than for methane, but are considered insignificant. Elastomeric materials used for seals and gaskets have higher permeability rates than polyethylene, but the total loss rates are still very low from economic and safety points of view.

In general, the metallic materials of interest have a low permeability to hydrogen and so leakage of hydrogen through steel, copper and other metallic pipe is not considered to be an issue. However, consideration should be given to the manner in which metallic pipes and pipework is joined to other sections and to auxiliary equipment. These joints and seals may allow leakage of the hydrogen gas through the seal material or if there is insufficient ‘tightness’ of the seal/joint.

The influence of hydrogen on the integrity of a metallic pipe or component depends on a number of factors which can be grouped under those related to the metallic material itself and those related to how the pipeline is operated. The former includes the steel’s strength, chemistry, impurities, microstructure, surface condition and processing and the latter includes the time, temperature, pressure, loading mode (including cyclic loading and its frequency), hydrogen concentration and gas purity.

Hydrogen embrittlement of steel can occur even with small hydrogen fractions but blends with up to 30% hydrogen should be safely transported in the low strength steels used in distribution networks. Impurities such as hydrogen sulphide and carbon dioxide promote hydrogen embrittlement so need to be controlled. Low operating pressures used in distribution networks limit susceptibility to hydrogen embrittlement, hydrogen cracking and issues with fracture toughness. The most significant issue for any steel pipeline operating in a hydrogen containing environment is fatigue. It is important to minimise pressure cycling for any steel pipeline containing hydrogen to limit fatigue crack growth.

Copper alloys are generally resistant to hydrogen embrittlement and so copper pipes are resistant to any material related issues when exposed to methane containing any level of hydrogen or biogas.

Domestic gas appliances and industrial pre-mixed gas burners are able to cope with biogas, SNG and will need to be tested and approved for all levels of hydrogen addition above 5%, although they may require minimal changes even at 30% hydrogen.

Non-premixed burners used for boilers and kilns may require modifications or adjustments to operation at all levels of hydrogen addition, but in many cases modifications may be minor, even at up to 30% hydrogen addition if burners have flexible designs. Gas turbines for power generation and gas engines traditionally can tolerate only minor changes in gas composition, and will need to be tuned or modified for blends containing hydrogen (including additions of even 1% hydrogen). Burner control systems will need to be developed to cope with variability in gas composition. The suitability of high strength steels used for existing stationary and on-board CNG vessels needs to be thoroughly investigated and the existing fleet should not be used with hydrogen concentrations above 2%.

There are a number of commercial issues that need to be addressed when adding renewable gas to a natural gas network. Addition of hydrogen, for example, lowers the volumetric heating value of natural gas and the Wobbe Index. Measures need to be taken to keep the Wobbe Index within the acceptable range, although hydrogen addition also improves ignitability and flame stability over a wider range of fuel/air ratios. Furthermore, higher volumes of gas will be required to provide the same amount of energy, and this may require additional compressors.

Adding hydrogen reduces the density of natural gas, and increases the required volumetric flow-rate to achieve the same rate of energy delivery. Consequently, velocity and pressure drop in distribution pipelines also increase for the same energy delivery. The locations, flow-rates and variability in flow-rate of hydrogen injection will influence the composition of blended gas throughout distribution networks. It may be necessary to use hydrogen storage tanks or pipelines to buffer injection rates if hydrogen supply is intermittent, and likewise it may be necessary to locate injection points at pressure let-down stations, and multiple other locations, to prevent wide variation in hydrogen concentration throughout the network.

Accurate measurement of composition and flow-rate are required for gas pricing. Instruments for determination of gas composition and for leak detection will need to be upgraded for renewable gas duty. Flow-rate metering will be more difficult if hydrogen concentration varies, because it will cause variation in gas density.

Various Acts and Regulations cover the supply and distribution of natural gas throughout the Australian States and Territories. Gaps in these Acts and Regulations for renewable gas blends with natural gas relate to materials selection, ensuring leak-tight components, quality assurance of metering and calculation of gas composition, appliance suitability, network isolation procedures, modifications to the type and amounts of odourant added, and possibly separation of gases to supply customers who use gas for heating with a different composition to those who require methane as a chemical feedstock. All these gaps can be addressed by historical and overseas experience with renewable gases, but may require further research to address issues pertinent to Australian conditions.

Safety issues relate mainly to explosion and flame radiation exposure. The risks are slightly more severe near to the release with addition of hydrogen due to widening of flammability limits and increase in flame speed. Explosion over-pressures are slightly higher and flame radiation is slightly higher closer the release. However the size of flames reduces slightly. For addition of hydrogen up to 50%, the differences from natural gas flames and explosions are not significant. Alarm set points for leak detection instruments that do not detect hydrogen could be adjusted to a lower level of methane detection for blends up to 30% hydrogen.

An upstream issue is to ensure that only low percentage hydrogen is used in high strength transmission pipelines, and avoidance of significant pressure cycling in such transmission lines. Use of dedicated hydrogen transmission lines with injection into low to medium pressure networks could be used to overcome this issue. The addition of hydrogen for the LNG export markets is not an option at this stage due to tight controls of gas specification. However, SNG and biogas would be possible.

In order to address the technical, commercial and regulatory issues associated with the injection of renewable gas distribution network a number of gaps in knowledge have been identified in this study. These R&D priorities will not only result in reliable and safe transportation of renewable gas in distribution networks, but will also assist in bringing down the lifecycle cost associated with the production, handling and use of renewable gas.

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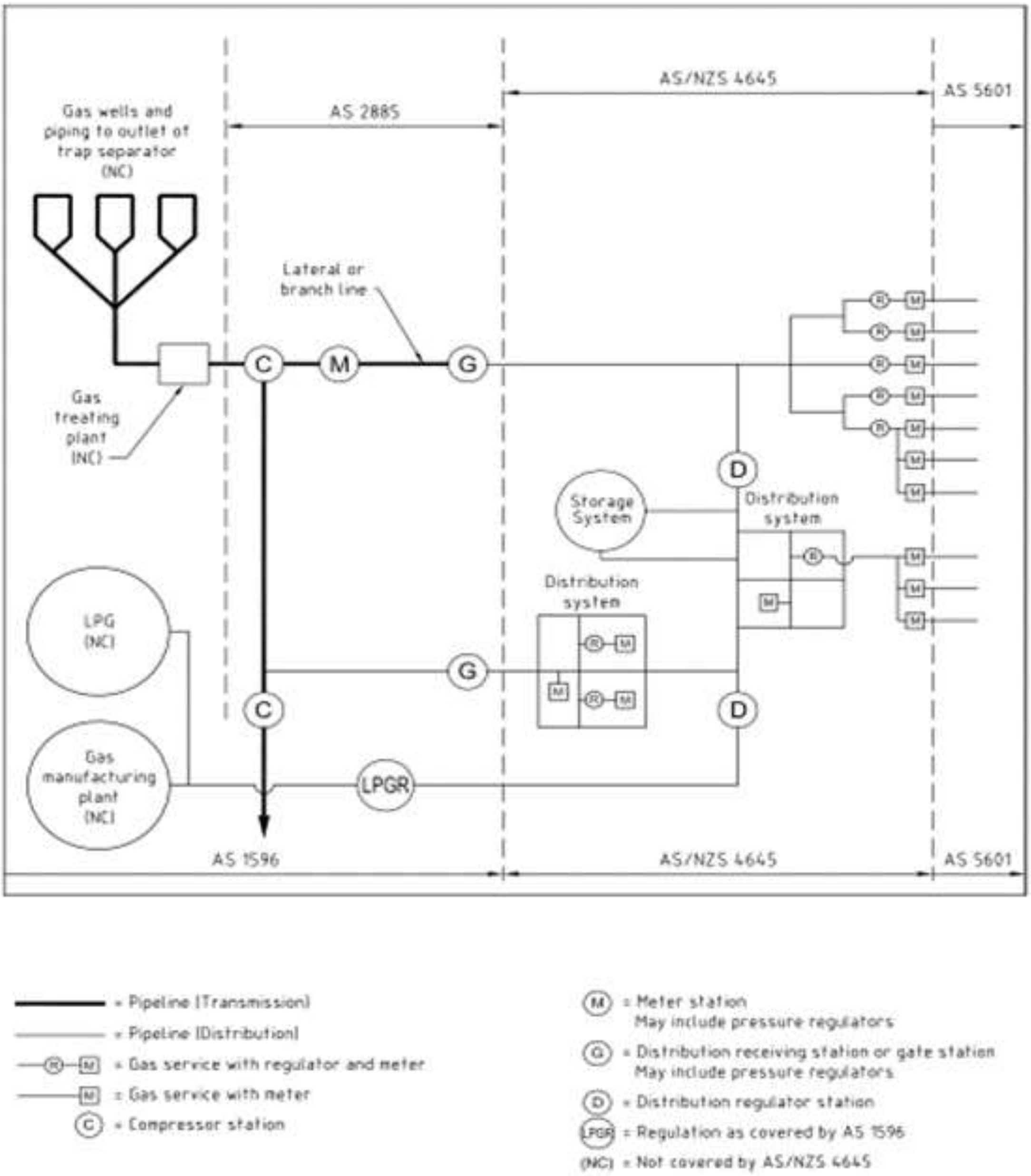
APPENDIX A: DIAGRAM OF APPLICABLE AUSTRALIAN STANDARDS



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