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Review

Hydrogen Blending in Gas Pipeline Networks—A Review

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Abstract: Replacing fossil fuels with non-carbon fuels is an important step towards reaching the ultimate goal of carbon neutrality. Instead of moving directly from the current natural gas energy systems to pure hydrogen, an incremental blending of hydrogen with natural gas could provide a seamless transition and minimize disruptions in power and heating source distribution to the public. Academic institutions, industry, and governments globally, are supporting research, development and deployment of hydrogen blending projects such as HyDeploy, GRHYD, THyGA, HyBlend, and others which are all seeking to develop efficient pathways to meet the carbon reduction goal in coming decades. There is an understanding that successful commercialization of hydrogen blending requires both scientific advances and favorable techno-economic analysis. Ongoing studies are focused on understanding how the properties of methane-hydrogen mixtures such as density, viscosity, phase interactions, and energy densities impact large-scale transportation via pipeline networks and end-use applications such as in modified engines, oven burners, boilers, stoves, and fuel cells. The advantages of hydrogen as a non-carbon energy carrier need to be balanced with safety concerns of blended gas during transport, such as overpressure and leakage in pipelines. While studies on the short-term hydrogen embrittlement effect have shown essentially no degradation in the metal tensile strength of pipelines, the long-term hydrogen embrittlement effect on pipelines is still the focus of research in other studies. Furthermore, pressure reduction is one of the drawbacks that hydrogen blending brings to the cost dynamics of blended gas transport. Hence, techno-economic models are also being developed to understand the energy transportation efficiency and to estimate the true cost of delivery of hydrogen blended natural gas as we move to decarbonize our energy systems. This review captures key large-scale efforts around the world that are designed to increase the confidence for a global transition to methane-hydrogen gas blends as a precursor to the adoption of a hydrogen economy by 2050.

Keywords: hydrogen blending; gas pipelines; methane-hydrogen mixture; energy transportation

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1. Introduction

Reducing greenhouse gas emissions, especially carbon dioxide and methane, to address global warming is one of the most urgent challenges faced by humanity. The Sixth Assessment Report of the Intergovernmental Panel on Climate Change concludes with a dire warning of the damage greenhouse gases have already inflicted on the Earth's atmosphere that will not be reverted without drastic measures [1]. Replacing fossil fuels with alternative non-carbon fuels, has been and continues to be examined.

Among fossil fuels, methane is the feedstock of choice for multiple applications. Figure 1 shows CO_2 emissions from fossil fuel sources: gasoline produces 67.6 kg of CO_2 per million kJ of energy generated, natural gas produces 50.3 kg of CO_2, while coal that is deficient in hydrogen (hydrogen to carbon ratio <0.7) emits 371.5 kg of CO_2 [2]. Natural gas has a higher energy content than other traditional energy sources, which makes it a fuel of choice for applications in industrial and commercial heating, transportation, and electricity generation that overlap most areas of petroleum and coal applications to allow for easy substitution. The infrastructure for gathering, transporting, and utilizing natural gas is already in place and reformed over recent decades. Natural gas contributed 32% of the total US energy consumption in 2019 [3].

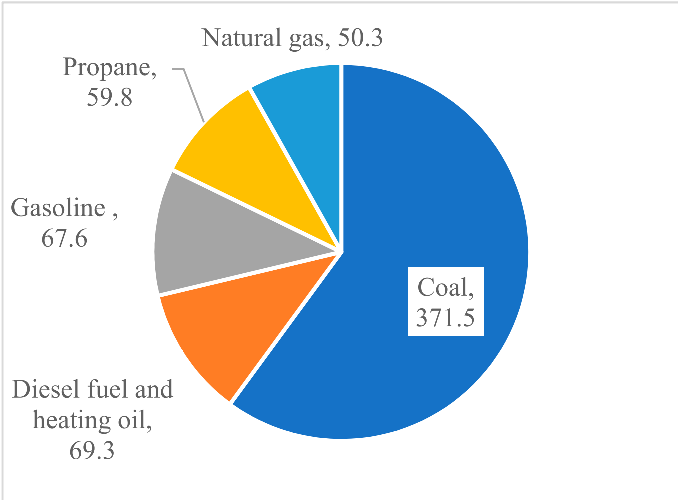

Figure 1. kg of CO2 emitted per million kJ of energy for various fuels in 2020 [2].

Given that extensive infrastructure for transporting natural gas is already in place, there is potential for repurposing the natural gas network to store and transport hydrogen and realize a carbon neutral economy. However, due to the vast property differences between hydrogen and natural gas, a large-scale energy system conversion to hydrogen requires a thorough examination of existing methods of production, storage, transportation, as well as developing efficient end-use applications that could use hydrogen as a fuel. A pragmatic approach towards a hydrogen economy that would involve: (i) using the existing infrastructure to first transport methane-hydrogen blends; (ii) understanding the challenges of introducing hydrogen; (iii) making operational modifications as needed; and (iv) progressively increasing the amounts of hydrogen in the blends over time to 100%, is being actively considered.

The successful realization of the hydrogen economy will require a coordinated effort from governments, research institutions, industries, policy makers, investors, and community leaders across the world. With a view towards enabling such a wide set of stakeholders to make informed decisions, this review provides an updated summary of the current status and implementation of hydrogen blending in natural gas pipeline networks.

The primary emphasis of this review was to highlight top-level state-of-knowledge across various stages in the lifecycle of a hydrogen economy—from methods for hydrogen production, to transportation of hydrogen blends and end-use applications. The salient properties and the benefits of methane-hydrogen blends are discussed. Particular emphasis is also placed on safety concerns that arise from combustion and materials issues in end-use appliances and transport pipelines, respectively. Furthermore, a comprehensive summary of hydrogen blending demonstration projects in various parts of the world such as US, Canada, UK, Europe, and Australia are also provided.

The lessons learned from the hydrogen blending studies and projects will enable the development of hydrogen compatible infrastructure with improved efficiency and safety.

2. Methane-Hydrogen Blends

2.1. Methods for Hydrogen Production

It is well known that hydrogen can be produced from both fossil and non-carbon sources. Hydrogen produced from fossil fuels can be either generated by reforming or pyrolysis of hydrocarbons, whereas hydrogen produced from renewables is either generated by water splitting or biomass processing. Commercially, hydrogen is primarily generated by Steam Methane Reforming (SMR) and to a lesser extent, by water electrolysis [4,5]. In SMR, hydrogen is produced by reacting methane with steam at high temperatures (978 K to 1255 K) mediated by a catalyst. This process is usually coupled with petroleum and chemical plants, in conjunction with other processes that require hydrogen. The hydrogen production efficiency of SMR ranges between 74–85% [5]. However, SMR generates CO_2 as a byproduct, and hydrocarbon reactant is derived from fossil fuels.

Electrolysis is an endothermic process for splitting water. An electrolyzer consists of a cathode and an anode. When an electrical current is applied to the water, hydrogen is produced at the cathode, and oxygen is evolved at the anode.

$$2H_2O \rightarrow 2H_2 + O_2$$

Three of the most common types of electrolyzers—proton exchange membrane (PEM) electrolyzer, alkaline electrolyzer and solid oxide electrolysis cells—are discussed below.

In a proton exchange membrane (PEM) electrolyzer, water is split into protons or hydrogen ions at the anode. Hydrogen is formed when the protons travel through the membrane and reach the cathode.

$$\text{Anode}: \quad 2H_2O \rightarrow O_2 + 4H^+ + 4e^- \ \text{Cathode}: \quad 4H^+ + 4e^- \rightarrow 2H_2$$

The PEM electrolyzers have fast heat-up and cool-off time, withstand high operating pressures across the membrane, and operate under a wide range of power inputs. Hydrogen produced from PEM electrolyzers has high purity and low operational costs. The challenges PEM electrolyzers are facing when implemented on a large scale is acidity, which limits the choice of electrocatalysts to just noble metals (Ir, Pt, or Ru). The polymeric membrane used in PEM electrolyzers are also somewhat expensive. In addition, the operating equipment is very sensitive, which can be damaged easily by careless operation, or presence of dust, and impurities [6].

In an alkaline or solid oxide electrolysis cells (SOEC) electrolyzer, water is introduced at the cathode, where it forms hydroxide ions and hydrogen. The hydroxide ions travel through the aqueous electrolyte to the side of anode, where they form oxygen and water.

$$\text{Anode}: \quad 4OH^- \rightarrow O_2 + 2H_2O + 4e^- \ \text{Cathode}: \quad 2H_2O + 2e^- \rightarrow 2OH^- + H_2$$

Alkaline electrolyzers have been commercially installed in a wide range of applications. Alkaline electrolyzers use 20–30% concentrated KOH/NaOH solution as the electrolyte, with asbestos diaphragm and nickel as electrodes. The major challenge alkaline electrolyzers face, are high equipment manufacturing costs. Like PEM electrolyzers, alkaline electrolyzers also need stable materials to operate in an electrode reducing and oxidizing environments [7].

In SOEC, where the electrolyte is a solid ceramic material, an elevated temperature (about 973–1073 K) is applied to reduce the electrical energy required for electrolysis. The high heat input can usually be supplied in nuclear energy facilities. Among the three types of electrolyzers, the SOEC electrolyzers are the least matured in terms of technology. The challenges facing the SOEC electrolyzers are associated with material selection, equipment durability/degradation, and operating conditions optimization [8].

Overall, green hydrogen is generated when electrolysis is conducted using electricity generated by renewable energies such as hydro, solar and wind. The electrolysis process itself emits no pollution with oxygen being its only byproduct. However, all electrolysis facilities require a high capital cost, while the overall hydrogen production efficiency (40–60%) is lower than the efficiency of SMR (74–85%) [5]. At present, the cost of hydrogen generated from renewable energy is about \$5 per kilogram, compared to the cost of hydrogen generated by SMR (\$1.40). The US Department of Energy (DOE) launched the first

Energy Earthshot initiative in 2021 setting a goal to reduce the cost of clean hydrogen to $1 per kilogram in 10 years [6,9].

2.2. Properties of Methane-Hydrogen Blends

When hydrogen is blended to methane, the new gas mixture exhibits different properties compared with either pure methane or pure hydrogen. The density of the methane-hydrogen mixture is lower than pure methane. One of the most practical impacts of the density difference is an increase in gas leakage volumetric flow rate. When compared to methane pipelines with the same leak size, methane-hydrogen pipelines show greater leakage flow rate [10].

The viscosities of different ratios of hydrogen in the methane mixture were investigated by Kobayashi et al. [11]. Their study utilized the capillary method (inner diameter of the capillary tube was 1.78 mm) to measure the viscosity of methane-hydrogen mixed gas at various temperatures and pressures. The study found that the viscosity of the methane-hydrogen mixture decreased non-linearly as the hydrogen concentration in the mixture increased. A significant reduction in the viscosity was observed when the hydrogen concentration was greater than 50% (Figure 2). A similar trend was observed in other viscosity related studies of methane-hydrogen mixture [12,13]. Within the temperature range of (20 °C to 70 °C), there was a 5–10% influence on the viscosity, while pressure had a marginal influence on the gas viscosity within the 20 kPa to 100 kPa range.

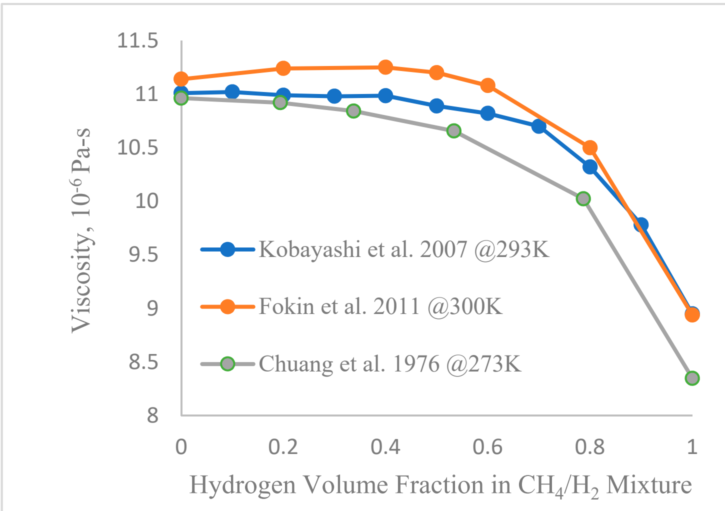

Figure 2. Viscosity variation as a function of hydrogen concentration in hydrogen-methane mixture (Data from references [11–13]).

The potential for interaction between the two gases in the methane-hydrogen mixture is also important in pipeline transportation and end-use applications. Marangon and Carcassi [14] investigated the dispersion and stratification properties of hydrogen and methane mixtures in a large-scale apparatus (dimensions: 3.23 m length, 2.75 m width and 2.81 m height) under ventilated and non-ventilated conditions. Gas chromatographs and sensors were used to analyze gas concentrations at different locations in the container. In the experiments with slow or fast ventilation, non-uniform concentration of the gas mixture was found at different heights in the container with sensors located at the same heights measuring the same gas concentrations. These results indicated that the methane-hydrogen mixture was well stratified in the test container with ventilation. In the experiments without ventilation, over a long residence time, the methane-hydrogen mixture tended to reach homogenization.

Another important aspect of the methane-hydrogen blends is their heat content. As presented in Figure 3, it is evident that the lower heating values (LHV) of methane hydrogen mixture increases slightly with increasing volume fraction of the hydrogen and shows a significant increase for blends with nearly 100% hydrogen.

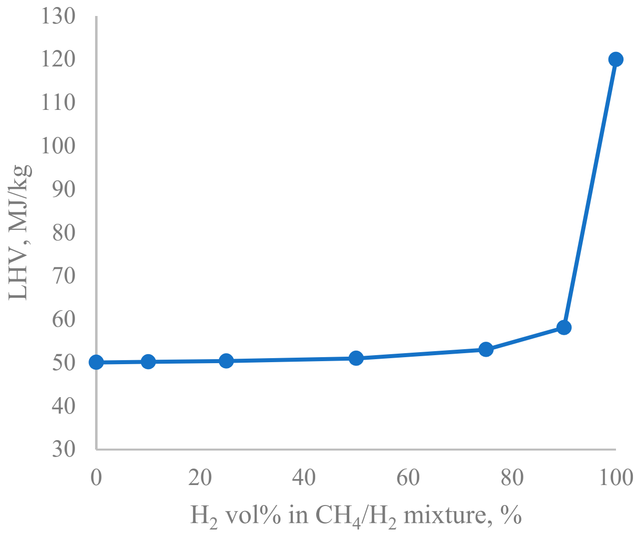

Figure 3. LHV of methane-hydrogen mixtures (Data from references [15,16]).

The properties of hydrogen-methane mixtures are important parameters in the design of hydrogen-methane pipelines as well as end-use applications using the mixtures. New hydrogen blending projects are also investing considerable time in further investigating the properties of hydrogen-methane mixtures as described in detail in Section 3.

2.3. Benefits of Hydrogen Blending

Apart from being an intermediate step in the process of moving away from fossil fuels, hydrogen blending in methane could have immediate benefits. First, hydrogen produced from wind, solar, hydro, and other renewable energy sources add more calorific value to the existing energy supply. Second, hydrogen blending in methane reduces greenhouse gas emissions, thus the mixture becomes "greener" in applications for heat and electricity generation. When used in automotive applications, hydrogen blended fuels are observed to reduce SOx, NOx, and particulate emissions [15,17]. Moreover, blending hydrogen in methane serves as a hydrogen delivery method to remote locations. Extraction of hydrogen downstream near end-use applications is a more cost-effective way rather than building an expensive high-pressure hydrogen pipeline. It is expected that in the immediate future, natural gas pipelines will routinely contain a proportion of hydrogen that is likely to be around 10% by volume as this is the maximum that pipelines can accommodate without downstream engineering modifications based on the current technology [18]. Another benefit of hydrogen blending is found in subsea natural gas pipelines. Obanijesu et al. [19] found blending hydrogen gas into subsea natural gas pipelines can inhibit hydrate formation. Hydrate formation in pipeline presents a great risk to safety. Methane plays a key role in the formation of hydrate during natural gas transportation. In addition to the problems associated with the high pressure and water concentrated environment found in the subsea pipeline system, small hydrate-encrusted water droplets can quickly agglomerate into larger hydrate masses inside the pipeline, resulting in plugging, which could lead to pressure build-up and finally explosion. The study found hydrogen, due to its small molecular size, demonstrates high inhibition ability that prevents hydrate agglomeration.

2.4. End-Use Applications of Methane-Hydrogen Mixtures

Methane-hydrogen mixture can serve as an alternative energy source in many different applications that commonly use fossil fuels. As end-use applications like engines and burners can be switched from gasoline to methane-hydrogen mixtures with few modifications, the performance of the gas mixture and its effect on pollution emissions have been closely examined in numerous studies.

Spark-ignition (SI) engines which have traditionally been gasoline powered, can be redesigned to be fed alternative fuels such as compressed natural gas [20]. Flekiewicz and Kubica [15] tested the methane-hydrogen fuel efficiency in an SI engine. They found that as hydrogen concentration increased in the methane-hydrogen fuel, the fuel consumption decreased. A higher engine power was achieved through reduction in the burning initiation time and allowing for more energy to be supplied to the engine cylinders. Another advantage of methane-hydrogen fuel is the reduction of emission due to the lowering of exhaust gas temperature. In comparison to gasoline, 30% volume hydrogen in methane reduces CO_2 emission by 37%. Methane-hydrogen improves the efficiency of energy conversion in SI engines, albeit with one drawback—the potential for knocking combustion when hydrogen volume ratio is higher than 30%.

Controlled Auto Ignition (CAI) engines can also be fueled with natural gas and biogas. Mariani et al. [17] studied the combustion of methane-hydrogen in an CAI engine and investigated the engine efficiency and pollutant emissions. The results of the study indicate that the addition of hydrogen to gaseous fuels increased their laminar flame speed and improved combustion stability in CAI engines. Hydrogen blending in methane reduces the initial gas temperature requirement which is further lowered as the hydrogen volume ratio is increased in the gas mixture. The lower temperature requirement has a direct impact on the NOx emissions as the higher hydrogen volume ratio in the mixtures leads to lower NOx emissions.

Chiesa et al. [21] performed a series of simulations on hydrogen combustion in gas turbines. The study summarized the effects of running pure hydrogen fuels in a large size gas turbine designed for running natural gas. The authors found three most prominent observed effects of using hydrogen as a fuel were: (i) a variation of enthalpy drop, (ii) a variation of inlet volume flow rate, and (iii) a variation of the heat-transfer coefficient on the turbine blades. For example, compared to natural gas, hydrogen combustion (with added diluent steam) increased the enthalpy drop by about 5%, that increased with increasing steam addition. A higher temperature stream from burning hydrogen caused performance decays in the cooling blades. Modifying the turbine blade height and adding compressor stages were proposed to redesign and improve the hydrogen fueled gas turbine performance.

Shih and Liu [22] tested a micro gas turbine by replacing the original natural gas fuels with methane-hydrogen blended fuels. Hydrogen content from 0% to 90% were tested in the combustion study using a gas turbine engine. The authors found that at a low hydrogen content, the flame temperature increases which is favorable for the combustion efficiency. However, as the hydrogen concentration increases, the fuel flow rate does not keep up, which lowers the flame temperature and causes engine power shortage. In a constant fuel flow rate study, increasing hydrogen concentration in the fuel elevates the flame temperature and combustor exit temperature and increases NOx emission. In a constant energy flow rate study, increased CO emissions were detected.

Leicher et al. [23] warned that the addition of hydrogen in natural gas changes the fuel gas properties, which, depending on the combustion system may raise the combustion temperatures and laminar combustion velocities. Appliances designed for natural gas may show risk of flashback, higher NOx emissions, and other safety concerns when switching to hydrogen enriched fuels.

Glanville et al. [24] tested different end-user appliances (a water heater burner, a furnace burner, and an ultra-low NOx burner) operating with 0–30% mixture of hydrogen blended methane as fuels. All tested burners using hydrogen blended fuels operated well with no signs of flashback, flame lift or excessive CO emissions. The overall efficiency of the appliances changed about 1–1.5% using the hydrogen blend fuels. No change or slightly decreased NOx emissions were measured in appliances.

Zhao et al. [25] tested a commercial oven burner with hydrogen injection into natural gas. The study found that 25 vol.% hydrogen could be added to natural gas without significant impacts. A 10% hydrogen addition increased the burner temperature by 63% compared to operating on pure natural gas, raising the burner temperature from 442 K to 548 K. As more hydrogen was introduced into the mixture (from 10% to 40 vol.% hydrogen), the burner temperature stayed around 548 K. The rise in burner temperature was attributed to the change in the flame position. Above 25% hydrogen, the flashback in the burner tube was the limiting factor. Hydrogen addition had minimal impact on NOx emission while an expected decrease in CO.

Wagner et al. [26] investigated fuel cells, which employed novel Gortex-based electrodes layered with Pd/Pt catalysts and found no significant difference between using pure hydrogen and 5% hydrogen in methane. The Gortex electrodes and alkaline electrolytes could utilize dilute hydrogen as a fuel with remarkable efficiency. The methane acted as an inert carrier gas and was not consumed.

In the French Hythane project, buses running on hydrogen blended natural gas have been operated in a small community for two years. The details of the Hythane project are presented in a later Section 3.2.1.

Upon recognizing that hydrogen blends may be safely used in many end-use applications with appropriate design modifications, considerable attention has been focused on identifying various modes of transportation of large volumes of hydrogen blends, the primary mode being the transportation through the network of pipelines as discussed in the following Section 2.5.

2.5. Gas Transportation Networks

2.5.1. Natural Gas Pipelines

Natural gas, methane-hydrogen mixtures, and hydrogen only pipelines are designed differently while sharing some common traits. Among the three pipeline systems, natural gas pipeline networks have been operated for the longest time. Methane-hydrogen mixture pipeline designs are based on the existing natural gas pipelines with a few modifications. Because hydrogen requires more pressure to transport in the pipelines, alternative transportation methods like truck delivery are also considered for lower cost of delivery when the volumes of blended gas that need to be transported are relatively low.

In a natural gas pipeline network, natural gas is first transferred from production sites to process and distribution centers through gathering lines. Gathering pipelines are usually small pipes with diameters ranging from 0.051 m to 0.203 m and operating at low pressures because gases can be pushed by the field compressors at the gathering facilities.

In the gas processing centers, natural gas impurities are removed to make pipeline quality gas. The purified natural gas is then transported through transmission pipelines. These transmission pipelines carry natural gas from the process centers to distribution sites which may be thousands of miles away, delivering about 8.01×10^{11} cubic metre of natural gas to about 76.9 million customers in the US [27]. According to American Gas Association [28], the total length of the natural gas transmission pipeline made of high-strength steel is about 4.38×10^{8} m. The gas pressure inside those pipelines can range from 1380 kPa to 10,300 kPa depending on the geographic location of the distribution sites. The diameters of the transmission pipelines range from 0.15 m to 1.2 m. Because of the high pressures that these pipes handle, specialized production techniques are required to build the steel pipes. To prevent corrosion, coatings are also needed to protect the pipes.

Compressor stations are necessary to provide pressure boosts along the pipelines when pressure is reduced in the pipeline due to frictional losses. Normally, compressor stations are located approximately 8.0×10^{4} to 9.7×10^{4} m apart along the pipeline. According to Homeland Infrastructure Foundation-Level Data (HIFLD) [29], the US natural gas network includes more than 1700 compressor stations. Typically, natural gas travels at a speed of 13.4 m per second through the transmission pipeline. When natural gas reaches a local gas utility, it will first encounter a gas station. The gas station receives natural gas from all sources of pipelines that originate from different production sites. The gas pressure at the gas station is reduced to 1.72–1380 kPa for distribution. Then, the gas station introduces an odorant to the natural gas as a safety feature (for leak detection) during end-use. The gas station also collects the data of the total natural gas received from different pipelines.

The pipelines used for distribution is typically smaller in size. The distribution pipeline diameters can be 0.05 to 0.61 m depending on the operating pressure adopted in each utility station. When the gas finally reaches the end-use customer, a pressure regulator will reduce the pressure to under 1.72 kPa.

2.5.2. Methane-Hydrogen Mixture Pipelines

While very few pipeline networks currently transport hydrogen blends on a large commercial scale in the US, several studies have developed pipeline models for the transportation of methane-hydrogen blends. Hafsi et al. [30] utilized Soave-Redlich-Kwong (SRK) equation of state (EOS) to model a steady state closed loop methane-hydrogen gas pipeline network. The modeling results suggest that injecting hydrogen requires additional compressor stations to maintain the gas pressure in long pipes to pay for the pressure loss compensation. Injection of hydrogen into natural gas pipelines increases the gas velocity significantly. This is justified by the fact that the presence of hydrogen in the mixture at a given pressure and temperature value increases the compressibility factor, which leads to a decrease in the gas density, resulting in an increase in the gas velocity. The overall natural gas pipeline network is illustrated in Figure 4.

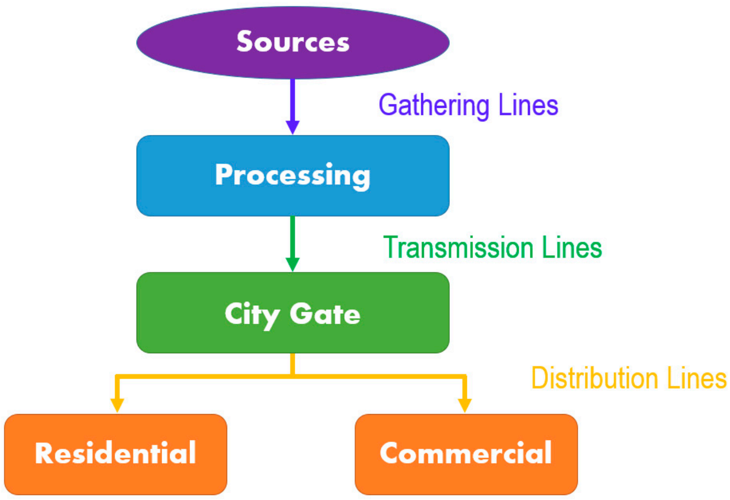

Figure 4. Natural gas pipeline network diagram.

Cadorin et al. [31] analyzed high pressure gas flow through a pipe with computational fluid dynamics models (CFD) using ANSYS CFX. Their study tested the energy transport efficiency of natural gas, biogas in two different compositions, and methane-hydrogen mixtures. The results of the analysis are presented in Table 1. The pressure drops, along with other variables, were used to calculate the energy specific toll (EST), which represents the energy necessary for transporting gases in a unit length of pipe. The higher the EST value, the greater the heating value of the gas is reduced during transportation. The study found that methane-hydrogen mixtures (e.g., 90% methane and 10% hydrogen) under high Reynolds number flow conditions, self-consumes almost two times more energy than natural gas during transportation, thus more energy is required for transporting methane-hydrogen gas blends. Tan et al. [32] demonstrated that the amount of increase in energy costs depends on the volume fraction of hydrogen and the nature of the flow conditions. The lowest energy costs are projected for transporting pure hydrogen under the conditions where the inlet velocity flow rates are similar to that used for transporting pure methane, while the highest energy costs are expected when hydrogen is transported at the same mass flow rate as methane.

Table 1. CFD results of fluids passing in high pressure pipe (partial data from reference [31]).

		Natural Gas	Biogas 1	Biogas 2	CH_4/H_2
CH_4 comp.	[% v/v]	82.5	60.0	40.0	90.0
CO_2 comp.	[% v/v]	1.0	40.0	60.0	0
H_2 comp.	[% v/v]	0	0	0	10.0
LHV	[kJ/kg]	47,351	17,627	9745	49,258
EST	[m^{-1}]	1.47×10^{-6}	1.80×10^{-6}	1.98×10^{-6}	2.86×10^{-6}

Bainier et al. [33] noted similar results in their study. In their experiments, 10%, 40%, and 100% of hydrogen blending in an international pipeline were tested. The authors found that at the same pressure ratio, the energy quantity delivered decreased by 4%, 14%, and 15 to 20%, respectively. This was due to an increase in the pressure drop when hydrogen was blended. In the study, more compressors were required to push the gas mixture in the gas network. As a result, compressors input energy increases respectively by 7%, 30%, and 210%. The energy transport efficiency was reduced when hydrogen was blended into natural gas network.

Injecting hydrogen in the natural gas distribution networks has also been investigated. Abeysekera et al. [34] conducted a series of case studies using steady state simulation models and found that the impacts of distributed hydrogen injections on the gas calorific value and specific gravity were within the tolerated range for end-use appliances. Furthermore, they also noted that gas mixture property variations from node to node and potential reverse flows during low energy demand seasons were important design considerations for optimal operation of the gas network. Through a simulation of hydrogen injection in a power-to-hydrogen electricity-gas system, Cavana et al. [35] analyzed hydrogen injections from fluid dynamic and gas quality perspectives. A small amount of hydrogen (1% by volume of the total) can cause the velocity of the gas flow to increase significantly resulting in the pipeline reaching its maximum flow capacity. In terms of gas quality, hydrogen blending reduced both relative density and higher heating values of the gas mixture. Fiebig et al. [36] using a simulation tool SmartSim, which is capable of tracking gas quality in gas grids, were able to determine the gas calorific values and composition of a hydrogen blended natural gas in a gas network. Dell'Isola et al. [37] calculated thermodynamic properties and compressibility factor of gas blends with hydrogen injections up to 25% in natural gas mixtures. It was noted that the relative density, heat capacity and higher heating value of the mixtures changed significantly when hydrogen was present in the natural gas network. The compressibility factor was also found to increase with increasing hydrogen content as well.

Cavana et al. [38] built a gas network simulation for calculating flow rates and pressures at different nodes of the pipelines. Their study suggested the injection of hydrogen into the gas network in the distribution parts, instead of the transmission part of the network as this strategy would remove the gas quality variations in the household lines, while not affecting the transmission infrastructure. However, addition of hydrogen in the gas network at a single location may cause heterogeneous hydrogen distribution and lower the hydrogen injection flow rate. Setting different pressure set points strategically was found to be a method that could alleviate the flow rate problem.

Quintino et al. [39] conducted a technical analysis of introducing hydrogen and biomethane in a natural gas infrastructure. Using the one-dimensional Cantera simulations, they demonstrated that hydrogen with volume fractions up to 20% are fit for the existing natural gas infrastructure with minor technical modifications. In the distribution network, the polyethylene (PE) pipelines are required to reduce hydrogen leakage when hydrogen content is above 30%. Additional compression stations are necessary to increase the pipeline pressure if hydrogen is added to the transmission lines. Gas quality tracking systems are required in the distribution lines when both hydrogen and biomethane are in the system.

Kong et al. [40] tested a helical static mixer in a gas network for mixing natural gas and hydrogen. Stratified gas mixtures can be found under conditions of laminar flow over short flow distances. This device was shown to improve the stratification of the gas mixture, while not significantly increasing the pressure loss in the pipeline.

2.5.3. Pure Hydrogen Delivery

In a pure hydrogen energy scenario, depending on the volumes of hydrogen that are needed, transport could be through trucking or via pipeline networks.

Wang et al. [41] examined the impact of hydrogen fuel from production, to delivery, and to vehicle use, on air quality. The lifecycle analysis of hydrogen was examined for three cases: (1) onsite hydrogen production, (2) hydrogen transportation in pipeline from centralized production, and (3) liquid hydrogen transportation in truck delivery from centralized production. All three cases demonstrated lower NOx, SOx, and CO emissions. The pipeline delivery system was found to have the lowest pollution emissions among the three pathways. For transportation by trucks, most emissions came from diesel truck emission on the road of delivery and the process to liquefy hydrogen. For the onsite hydrogen production pathway, the associated emissions were very low due to lack of a need for hydrogen transportation. However, emissions from the hydrogen production onsite could potentially be carried to urban areas by wind.

For relatively lower volumes, hydrogen is primarily delivered to stations in gaseous form by trucks at the present time. However, for higher volumes, it is expected that pipeline delivery of hydrogen will have low operating expenses, high reliability, long service life, and low public visibility. Penev et al. [42] referred to the intra-city hydrogen delivery pipeline network in the US as the "HyLine" system. The "HyLine" system consists of hydrogen produced at industrial or commercial sites near or within urban areas, compressed to 103,400 kPa, stored at centralized facility, and delivered via high-pressure pipeline to retail stations. Advantages of the HyLine system include minimization of hydrogen storage and compression equipment sited at retail refueling stations as one larger compression station is more cost efficient than several smaller compressor units. One of the biggest challenges of constructing the "HyLine" system was the high-pressure system involved with hydrogen storage and transportation. Compared to the current natural gas pipeline system, the design of high-pressure hydrogen pipeline system requires a careful assessment with regards to the materials selections for the pipes and safety issues during operation.

2.6. Safety

2.6.1. Combustion Issues

Blending hydrogen into methane pipeline, depending on the blend concentrations, can lead to a higher incidence of overpressure, explosions, leakage, and cracking. The addition of hydrogen also raises the severity of explosions, which can cause greater damage to the infrastructures, risks to human life, and pollutions to the environment. Hence, a more stringent risk assessment needs to be adopted in designing methane-hydrogen mixture pipelines compared to designing the natural gas pipelines.

Shirvill et al. [43] observed that the maximum overpressures generated by methane-hydrogen mixtures with 25% by volume or less hydrogen content, are not likely to be significantly greater than those generated by methane alone. Their work suggested that the addition of less than 25% by volume of hydrogen into pipeline networks would not significantly increase the risk of explosion. Lowesmith et al. [44] found that the behavior of a methane-hydrogen mixture containing less than 30% by volume of hydrogen was likely to be similar to that of natural gas. However, for mixtures containing 40% or more hydrogen, there was a significant risk of generating damaging overpressures and a risk of deflagration to detonation transition (DDT).

Some parts of the pipeline raise higher safety concern than others. Higher concentration of hydrogen in methane-hydrogen-air mixtures can affect dramatically the maximum overpressure, flame speed, and temperature rise in case of an explosion [45].

Di Sarli and Di Benedetto [46] studied the laminar burning velocities of methane-hydrogen/air mixture using the CHEMKIN PREMIX code. It was found that the hydrogen blended gas mixtures have lower laminar burning velocities compared to the linear interpolated values with the pure fuels. When the hydrogen mole fraction in the mixture was less than 0.5 or greater 0.9, the laminar burning velocity increased linearly with the increase of hydrogen mole fraction. In the regime between 0.5 and 0.9 hydrogen mole fraction, a non-linear increase in the laminar burning velocity values were observed. The Le Chatelier's Rule-like formula correlated the calculated laminar burning velocities. The authors found that the composition of H radicals that are generated during the combustion of the hydrogen-methane mixtures controls the laminar burning velocity.

Hu et al. [47] also found three regimes in laminar burning velocities of methane-hydrogen/air mixture in both experimental and numerical studies. In regimes where the hydrogen fraction was less than 0.6 or higher than 0.8, the laminar burning velocity increased linearly with the increase of hydrogen fraction. The laminar burning velocity increased exponentially in the regime between 0.6 and 0.8 hydrogen fraction. When there was an increase in the amount of hydrogen that was added to the fuel, an increase amount of H^+ and OH^- radicals were present in the reaction zone of the premixed flames. The radical concentration was found to correlate with the laminar burning velocity.

According to Di Sarli [48], an increase of hydrogen mole fraction in a methane-hydrogen fuel increases the intensity of the flame-vortex interaction, which leads to a higher burning rate. More sub-vortices are generated as the hydrogen mole fraction increases. Different mole fraction of hydrogen in the mixture fuel changes the nature of the flame front from a wrinkled regime (hydrogen fraction < 0.2) to a more vigorous regime (hydrogen fraction > 0.2). In a separate study conducted by Di Sarli and Di Benedetto [49], a Large Eddy Simulation (LES) was used to simulate hydrogen-methane/air premixed flames around toroidal vortices. The unsteady flame propagation was found to be dominated by an increase in flame reactivity with an increase in the hydrogen mole fraction. The hydrogen diffusion characteristic time was found to be higher than the characteristic time of flame roll-up around the vortex, attributing to the non-equidiffusive effects leading to the flame behavior.

Salzano et al. [50] experimented with the explosions of methane-hydrogen/air mixture in a closed cylindrical vessel. The maximum rate of pressure rise, and the laminar burning velocity were quantified. The data showed that the rate of pressure rise increased with increasing hydrogen fraction in the fuel. The laminar burning velocity also increased as the hydrogen fraction increased. However, a Le Chatelier's Rule-like formula can only predict the laminar burning velocity of fuels with hydrogen mole fraction less than 0.5. Shen et al. [51] also suggested that hydrogen addition to the blended mixture of methane-hydrogen significantly increased the explosion risk and severity. Adding hydrogen to the gas mixture shortened the combustion time and enhanced the pressure buildup in a 20 L spherical vessel.

2.6.2. Materials Issues

In all three stages of pipeline, fabrication, processing, and service life, the presence of hydrogen atoms and their contact to the pipe wall is inevitable. Because of their miniature size, hydrogen atoms can diffuse through iron and its alloys and occupy the interstitial sites of defects inside the metal. Factors affecting the interaction between hydrogen and steel can be categorized into environmental sensitive and bulk interactive.

Two models describe the hydrogen interaction with metal. In the direct hydrogen entry model, also known as the one-step absorption mechanism, hydrogen atoms are assumed entering the metal in the same elementary state as it leaves the metal. According to Zheng et al. (1995), the direct hydrogen entry model is valid for palladium and HY-130 steel [52].

The other hydrogen model is called the indirect hydrogen entry model or the two-step absorption mechanism. Hydrogen atoms are expected to go through a hydrogen evolution reaction when they pass through the adsorbed state on the metal surface. In the chemical equations given below, M is referred to the metal surface adsorption site, while MH_{ads} is the adsorbed hydrogen. In acidic media, the Volmer reaction will reduce proton on the metal surface:

$$H_2O^+ + M + e^- \leftrightarrow MH_{ads} + H_2$$

In neutral or alkaline media, water will dissociate and adsorb hydrogen on the metal surface:

$$H_2O + M + e^- \leftrightarrow MH_{ads} + OH^-$$

In the second step, the adsorbed hydrogen may go through one of the two reactions.
(1) Heyrovsky electrochemical reaction:

$$MH_{ads} + H^+ + e^- \leftrightarrow M + H_2$$

(2) Tafel chemical recombination reaction:

$$2MH_{ads} \leftrightarrow 2M + H_2$$

For hydrogen interactions with iron and steel, the majority of the adsorbed hydrogen transforms back to hydrogen gas in one of the two chemical equations above. Only a small portion of the adsorbed hydrogen is expected to diffuse into the metal as metal-hydrogen bond is weak [53].

The hydrogen that diffuses inside the steel can cause hydrogen embrittlement. Hydrogen embrittlement (HE) is another cause of steel pipe failure that can be found in many existing cast-iron and stainless-steel pipelines. Hydrogen embrittlement can cause severe failure in materials induced by hydrogen in presence in metal during fabrication, processing, and service life. The presence of hydrogen atoms in a solid has a large influence on both crack nucleation and propagation. Hydrogen interacts with the crystal lattice of steel, nickel, titanium, and other metals [54]. Even steel conforming to the American Petroleum Institute (API) 5 L specification that has outstanding mechanical properties, is susceptible to cracking caused by exposure to hydrogen [55]. The mechanical properties such as ductility and fracture toughness are reduced when HE occurs. Pipelines with added hydrogen presents a higher risk of pipe cracking and failure.

Diukic [56] conducted a case study on the HE failure of a boiler tube while it was in operation. The damaged equipment was a carbon steel boiler evaporator (water wall) tube installed in a 210 MW coal-fired power plant. The dimensions of the tube were 0.06 m inside diameter by 0.006 m thick. It was operated under a pressure of 15,500 kPa at 450 K over 73,000 h of operation. Figure 5 illustrates the fracture location on the pipe. The causes of the mechanical failure of the boiler tubes were summarized in the following points. (i) Local intensive acidic corrosion became a source of hydrogen. Hydrogen-induced corrosion was enhanced by thermal cycling of the tube during operation. (ii) High temperature hydrogen attack (HTHA) resulted in a "window" type fracture. (iii) The HE damages provoked by the weld geometry defect and excessive root penetration, resulting in uneven tube metal enrichment with hydrogen near the fracture. (iv) Hydrogen embrittlement on the tested species indicated hydrogen enhanced localized plasticity (HELP) and hydrogen enhanced decohesion (HEDE) was detected at high hydrogen concentrated locations. (v) The macro hardness value was very well correlated with the hydrogen concentration in the metal. (vi) The simultaneous action of HELP and HEDE was responsible for the decline in steel ductility.

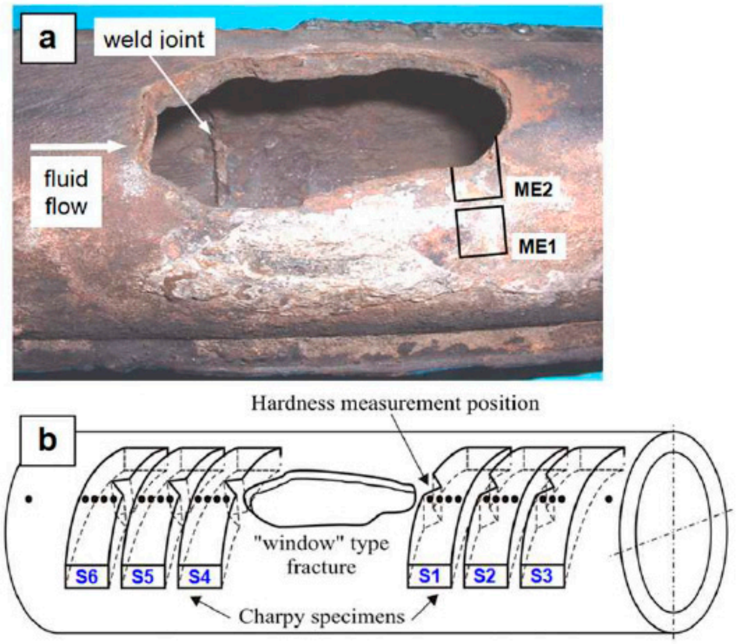

Figure 5. (**a**) damaged boiler tube facture; (**b**) position of facture on the boiler tube [56].

A hydrogen embrittlement study on a hydrogen blended natural gas pipeline by Dadfarnia et al. [57] drew different conclusions. Their research investigated the fatigue crack growth in the inner diameter surface of steel pipes carrying hydrogen blended natural gas under actual pressure fluctuations. The distribution line pipes with size ranging from 0.15 m to 0.30 m were selected. The results of their experiments indicated that, even in the worst-case scenario, the X42 line pipes with initial crack depths that were less than 40% of the wall thickness, the axial cracks do not reach 75% of the wall thickness over a period of 100 years. In other cases, with an initial crack depth less than 50% of wall thickness, the failure criterion for 75% of wall thickness was also not reached in 100 years. The paper concluded that if the initial crack depth is less than 40% of the wall thickness, hydrogen blended natural gas can be transported safely in metal pipelines.

A lesser-known challenge to safety is the more recently determined evidence of Hydrogen Induced Corrosion. In electronic structure calculations for body-centered cube (BCC) Fe with or without Hydrogen reported by Itsumi and Ellis [58], it was determined that the introduction of interstitial hydrogen into the ferrous based lattice leads to interaction between the H 1 s and Fe 4 s orbitals rendering a weakening of the Fe-Fe bonds, which in turn would be expected to lower the activation energy of the anodic oxidation and dissolution of Fe and to bring about lattice dilation. Nash et al. [59] in studies of hydrogen cathodically charged A710-HSLA steel, reported lattice dilation measured by neutron diffraction. To what extent this enhancement in anodic activation effect is influential on major passivators such as Cr and Mo has yet to be determined. However, in a study of hydrogen in Ni, an important constituent of austenitic steels, J-Z Yu et al. [60] determined from first principals calculation, that hydrogen dissolved in Ni indicated a linear increase in lattice parameter with hydrogen concentration. This is shown in Figure 6 below. However, electrochemical studies of hydrogen in Ni have not been reported.

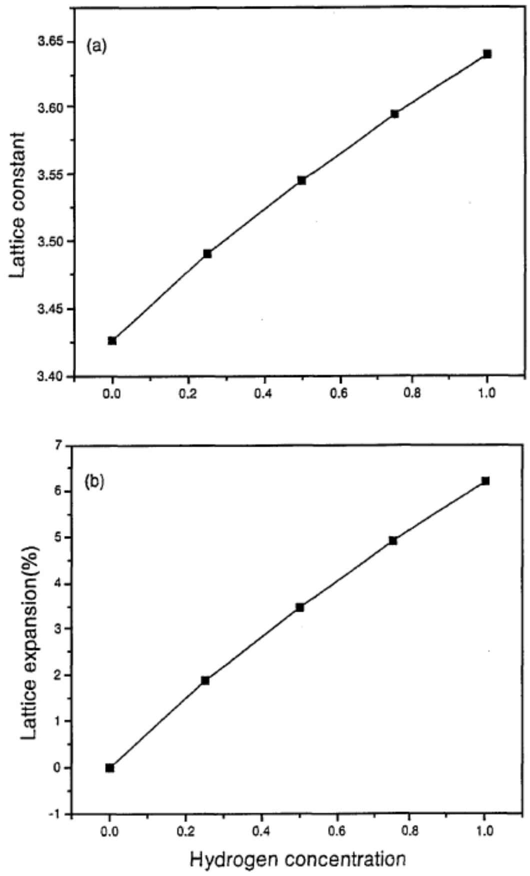

Figure 6. Lattice constant (**a**) lattice expansion (**b**) changes with concentration of Hydrogen [60].

In a comprehensive study of the effect of cathodically hydrogen charged 1018 plain carbon steel on corrosion behavior, Thomas et al. [61] reported a lowering of the open circuit potential and an increase the anodic current density. While it is expected that hydrogen oxidation will be responsible for a fraction of this anodic current, online inductively coupled plasma—optical emission spectrometry (ICP-OES) provided direct evidence of the enhancement of dissolved iron because of the hydrogen charging. This is indicated below in Figure 7. Additionally, several papers have reported electrochemical analysis of stainless steels indicating serious degradation of the passive state due to the degree of hydrogen cathodic charging [62,63].

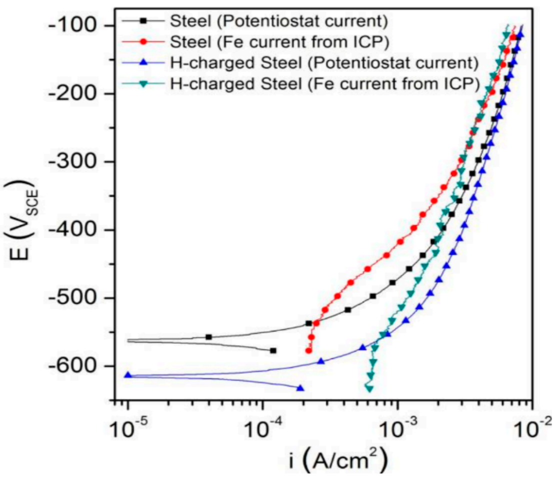

Figure 7. Influence of hydrogen charging on 1018 steel [61].

The literature on stainless steels is relevant to this discussion on pipeline safety for two reasons: (a) the passive films formed on high strength steels (HSS) are not expected to be as resistant to general and localized corrosion due to the lack of sufficient Cr and (b) understanding the mechanism of hydrogen degradation of the passive state of stainless steels will provide an excellent basis for understanding the mechanisms of degradation on the fundamentally lesser corrosion resistant passive films formed on the HSS. It is important to note that most studies of hydrogen degradation of the passive state of stainless steels follow the common practice of hydrogen loading by cathodic charging. However, several published papers indicate that cathodic charging and high-pressure gas soaking of steels appear to be comparable methods of hydrogen loading, resulting in no obvious difference in material properties that are due to the method by which hydrogen enters the steel [64–66].

In considering the possible role of hydrogen, or specifically the anodically oxidized form, protons, in destabilization of the passive film formed on ferrous alloys, including stainless steels, it is important to first review the role of bound water in the formation and stability of passive films formed on stainless steels, according to Okamoto [67]. Okamoto considered two classes of bound water: (a) Aquo and olation groups, i.e., M-H_2O and M-OH at lower passive potentials and (b) Oxo and olation bridges, i.e., M-O or M-OOH at the higher passive potential range. The latter class represents the more developed and stable passive film structures, following the degree of electric field assisted deprotonation, as the anodic potential is increased. Higher oxidizing potentials also promote higher cation oxidation states, which also forces a rebalancing of anion charge from OH^- to O^{2-}. In Cl^- solutions OH^- can be more readily displaced by Cl^- than the Oxo and Olation bridges. This may lead to localized passive film breakdown and the onset of pitting. The question remains as to whether anodic oxidation of hydrogen will inhibit deprotonation and therefore, passive film stabilization.

Reflection high-energy electron diffraction (RHEED) studies by Clayton et al. [68] on the passivity of 304 Stainless steel in de-aerated 0.5 M H_2SO_4 (the same alloy composition and electrolyte as used by Okamoto) supported the bound water model of Okamoto and revealed the intermediate formation of CrOOH. An outer deposit film of iron products, not associated with passivation, also showed the presence of bound water. The latter was shown by RHEED to first form a highly hydrated green rust species that transformed to iron hydroxides and eventually α-FeOOH. Formation of Fe and Cr oxyhydroxides was rapid at higher passive potentials and slower at lower potentials, indicating the lingering presence of bound water and hydroxides. Clearly the deprotonation process is electric field assisted. However, in general, at low and high passive potential ranges, a bilayer film was observed by X-ray photoelectron spectroscopy (XPS) with the inner region favoring oxalation [69]. Typically, intermediate compounds of oxyhydroxide are reported and at higher potentials, oxides.

Generally, a bilayer is usually formed with the greatest degree of deprotonation being observed in the inner layer of the film. This process can occur at lower potentials after holding at a passive potential for longer times and higher potentials at shorter times as confirmed by RHEED studies in 304 stainless steel in de-aerated 0.1 M H_2SO_4. The anodic oxidation of metal lattice hydrogen forming protons suggests a possible link between several reports of hydrogen destabilizing passive films and deserves further study. However, it has been shown from XPS studies of passive films formed in acid on stainless steels containing molybdenum that the outer region of the bilayer passive film contains molybdate anions bound to ferrous cations [70]. The Pourbaix diagram for Mo indicates, however, that the greatest stability of Molybdate should occur in alkaline environments [71]. Indeed, XPS studies of the passive film formed on Mo under the same electrochemical conditions was absent of molybdate and primarily composed of MoO_2 and MoOOH. However, in studies in which a bi-electrode, i.e., Mo-Fe or Mo-Ni, in close proximity was polarized in the passive region of molybdenum, active dissolution of Fe and Ni resulted in a nanoscale deposit film of the corresponding molybdate on the Mo [72]. Thus, it is implied that the high OH- content of the outer layer may support formation of molybdate. Relevant to this review, it has been observed that the nanoscale deposit layer of molybdate salt provides a strong enough negative fixed charge field to be able to both promote deprotonation of the chromium component of the inner layer of the passive film by assisting OH bond stretching and provide a negative fix charge repelling Cl- ion ingress, thus providing higher resistance to chloride induced localized attack of the passive film and eventually pitting. This behavior has been summarized in a bipolar model of passivity Figure 8.

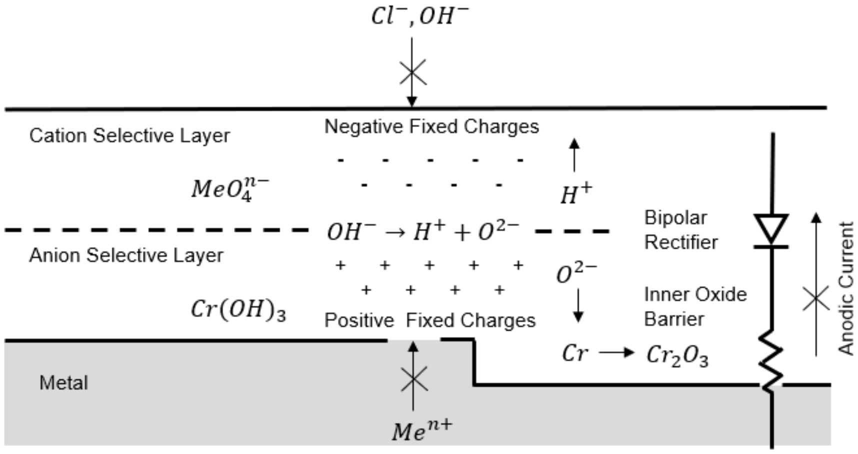

Figure 8. Schematic: bipolar passive film model (adapted from [72]).

However, when the anodically oxidized hydrogen enters the passive film, this model would be expected to breakdown under two conditions: (a) the oxalation process may be inhibited by the reduction of O^{2-} by H^+ to OH^- and (b) possible shielding of the Molybdate anion by protons weakening repulsion of surface adsorbed Cl^- ions and its influence on the oxalation process. Indeed, this may explain the reported enhancement of pitting of 304L SS [62] in the former case and 904L SS [63] in the latter, following application of high cathodic charging currents. Clearly, the passive film system of stainless steels is ideal for studying the potential effect of hydrogen on passive structure and stability. However, high strength pipeline steels will be expected to be exposed to milder, closer to neutral pH environments where passivation is required to be facilitated by an iron based passive film. In this case, the stability of the Fe-O and Fe-OOH bond linkages will be expected to be vulnerable to destabilization by anodically oxidized hydrogen. A further issue is the complexity of the microstructure of HSSs and interaction with hydrogen. In studies of X80 pipeline steel weld susceptibility to hydrogen exposure, Xue and Cheng [73] reported that the degree of hydrogen accumulation following cathodic hydrogen charging varied with location in the order of heat affected zone (HAZ) > base steel > weld. These data, shown in Figure 9, were determined by electrochemical measurements using a modified Devanthan-Stachurski cell.

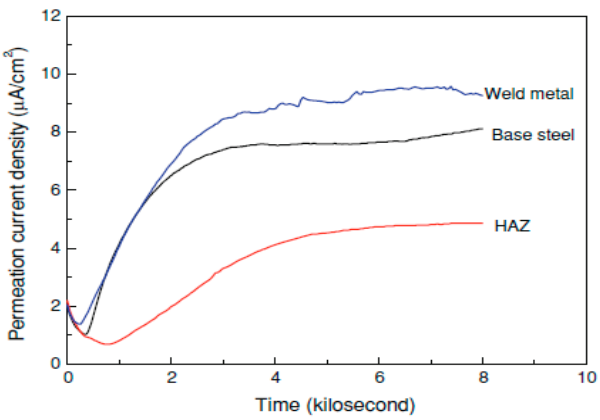

Figure 9. Hydrogen permeation current curves [73].

Electrochemical studies in NS4, a simulated soil solution of near neutral pH, revealed that localized corrosion was more active at the highest hydrogen trapping site, the heat-affected zone (HAZ), and lowest at the lowest hydrogen trapping site which was the weld. This was attributed to the local microstructure of bainite, ferrite and randomly distributed cementite and presumably to trapping at the phase boundaries. As shown in Figure 10, the degree of hydrogen trapping was directly related to the enhancement of anodic current density. The potential role of phase boundaries and local trapping suggests a possible synergistic role of hydrogen in enhancement of corrosion.

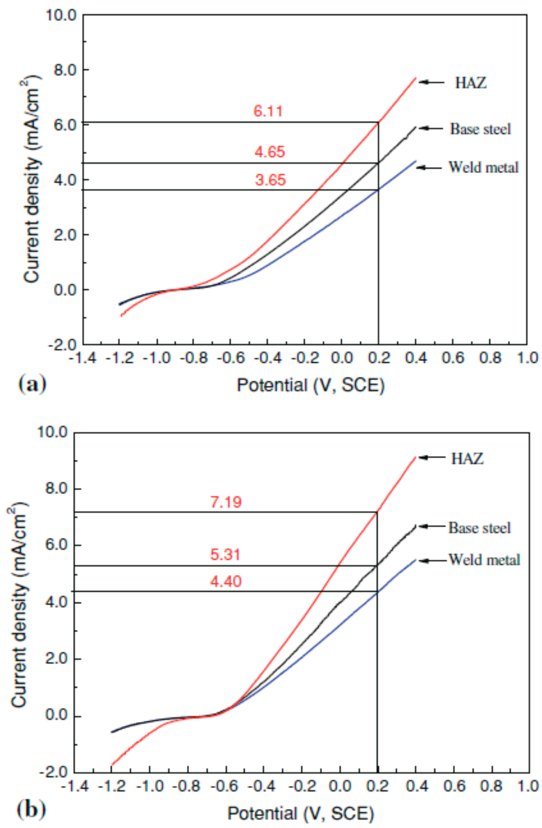

Figure 10. Polarization curves measured at various zones of the weld in NS4 solution in the absence (**a**) and presence (**b**) of hydrogen-charging at cathodic current density of 10 mA/cm^2 for 2 h [73].

3. Hydrogen Blending Projects

The concept of blending hydrogen in existing natural gas networks has been investigated in many parts of the world (Table 2). In particular, several long-term projects with trials of hydrogen-blending in small communities have been successfully conducted in Europe, while there have been fewer such projects in the United States, thus far. Key ongoing at-scale hydrogen blending projects are summarized in this review.

3.1. Hydrogen Blending Projects in the United Kingdom (UK)

3.1.1. HyDeploy

The UK has an obligation to reach net zero carbon emissions by 2050 under the UK Climate Change Act [74]. Over one-third of the UK carbon emissions are from the heating sector, where natural gas is used for heating approximately 23 million households [75]. The HyDeploy project is the UK's first hydrogen blending deployment project that was initiated in 2019. The goal of the project is to blend 20 mol% of hydrogen in the current UK's gas grid keeping the same end-use appliances while reducing overall carbon emissions.

The HyDeploy project has been divided into three phases. In Phase 1, the 18-month laboratory tests led by Keele University provided scientific verification for the operational safety of 20 mol% hydrogen in the gas network and end-use appliances as the risk analysis of the blended gas mixture must meet the UK's Health and Safety Executive (HSE) requirements. Sample domestic appliances that were tested by Keele University included gas boilers (including 600 kW commercial boilers), cookers, and stoves. The tests were designed to understand the performance and limitations of the selected appliances in the hydrogen blended gas. It was found that when running on the hydrogen blended gas, carbon monoxide outputs in the test boilers decreased by up to 0.5 mol%.

An increase in the gas flame speed was observed only when the hydrogen content was greater than 80 mol%, which was beyond the scope of the practical implementation of the project. The results of the experiments indicated that all tested domestic appliances could safely operate with hydrogen concentrations of up to 28.4% [76].

In addition, gas characteristics of 20 mol% hydrogen in natural gas have been investigated for understanding their dispersion, flammability, and combustion characteristics. Hydrogen and methane do not show significant separation at 20 mol% hydrogen. The buoyancy of hydrogen blended natural gas is higher than that of pure natural gas, which is good for dispersion in the case of leakage. The leakage rates of the 20 mol% hydrogen blended natural gas and pure natural gas in a laminar flow were found to be equivalent. In turbulent flows, a 20 mol% hydrogen mixture leaks 10% more than pure natural gas. A 20 mol% hydrogen blended natural gas does not have the risk of self-detonation, and the Low Flammability Limit (LFL) of the 20 mol% hydrogen blended natural gas is 4.75%, which is lower than the LFL of pure natural gas, which is 5%. The Atmospheric Explosion (ATEX) rating of electrical equipment for 20 mol% hydrogen mixture is the same as that of pure natural gas. For gas detection in the event of a leak in the gas network, it was found that a carbon monoxide detector in conjunction with a flammable-gas detector would serve the purpose of detecting 20 mol% hydrogen gas mixture.

The Phase 2 of the HyDeploy project focuses on the construction and preparation of the hydrogen blending network. In summer 2019, Keele University built a hydrogen blended natural gas network that included a 0.5 MW electrolyzer, a hydrogen blending grid entry unit, and sample monitoring stations (Figure 11). The focus of the Phase 2 trials was to train the operational engineers from Keele or third-party contractors with operation and safety guidelines. Furthermore, all residents in the trial area were offered Gas Safe checks on a regular basis. For the last trial phase, the Keele network went through a 10-month trial period to demonstrate the safety of the hydrogen blended natural gas network. Piping material tests were conducted by soaking different materials in hydrogen blended natural gas for nine weeks and tensile tests were performed on the materials afterward. The study found no increment in the degradation of piping materials after exposure to a 20 mol% blended hydrogen in natural gas. Another Quantitative Risk Assessment (QRA) on the Keele network was conducted and found that the 20 mol% hydrogen blended gas did not endanger the safety of end users.

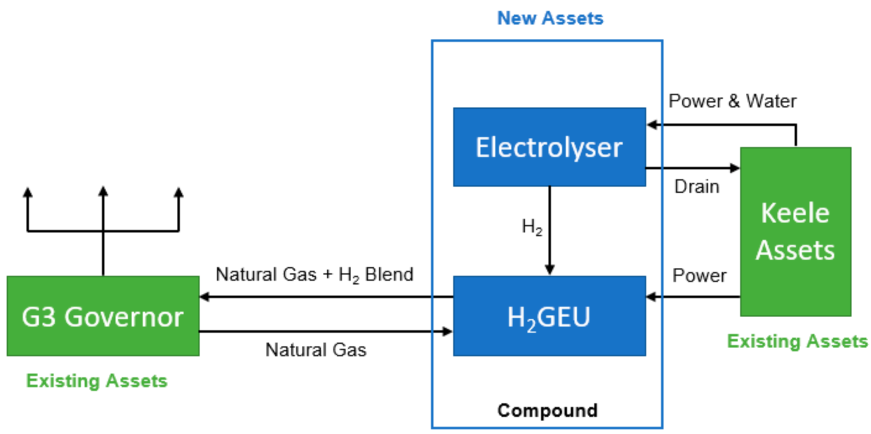

Figure 11. HyDeploy process design flow chart (adapted from [76]).

The proposed next step of the HyDeploy project is called HyDeploy$_2$, which is the intermediate step between the trial-scale deployment and commercialization. Two trials, started in 2019, were aimed at supplying about 1500 households with hydrogen blended gas in four years. HyNet is the final commercial realization of hydrogen blending into natural gas network. The goal of the HyNet was to reduce carbon emission by more than 1 MT/yr. It is a non-disruptive project to achieve decarbonization in the Manchester-Liverpool region that will eventually impact over two million households. HyNet will also assist existing industrial clusters achieving decarbonization through hydrogen conversion as the results of the trial project become available over time [76].

3.1.2. Other UK Hydrogen Projects

In addition to the HyDeploy project, there are several other ongoing hydrogen projects in the UK that are aiming to reform the natural gas networks and reduce the nation's carbon emission.

The East Neuk Power to Hydrogen Project led by SGN utilizes the surplus electricity produced from Fife's offshore renewable energy to generate green hydrogen that can be injected into a natural gas gird, utilized in a pure hydrogen grid, or be used for fueling automobiles. A model was developed to assess the electricity system of Fife and the power transportation system between the city of Fife to the rest of UK. The modeling results helped evaluate the feasibility of the hydrogen project. It was found that Fife's low-cost/low-carbon power was unmatched by other regions in the East Neuk for cost effective hydrogen production. Hence, exporting the hydrogen produced from Fife was expected to be advantageous than merely applying it locally. In order to successfully execute the vision, hydrogen storage and transportation issues need to be addressed carefully for future development [77].

The company SGN, in partnership with Pale Blue Dot and National Grid, has initiated another hydrogen blending project called the "Aberdeen Vision". This project has tested the injection of 2% hydrogen in an existing gas network in Aberdeen to supply 300 homes and found no issues that could impede implementation. Hydrogen is produced at St Fergus Gas Terminal using SMR from a carbon capture and storage (CCS) facility. Duplicating the Aberdeen Vision hydrogen project in other regions in the northeast Scotland can be achieved because of their geological advantages. Most of those regions have access to large volumes of gas coming onshore. New pipelines will be necessary to advance the project to the next planned stages that envisions raising the concentration of hydrogen injection to 20% and eventually, to 100% [78,79].

Another hydrogen blending project is in progress in the North West and North Wale region which is called the HyNet North West project. With the aim of reducing carbon dioxide emissions, a CCS process was adopted to transport industrially emitted carbon dioxide in an underground pipeline which led to depleted oil and gas reservoirs under the seabed. The second goal of the HyNet project was to produce hydrogen from natural gas. As envisioned in the proposal, the hydrogen production plant is expected to produce 350 MW of hydrogen by 2025 to supply 30 TWh of energy annually by 2030. The HyNet project is currently in phase 1, the development phase. The goals of this phase are (1) searching the best method for decarbonization and providing clean hydrogen power, (2) building a new CCS infrastructure, and (3) running hydrogen blending trials in gas networks for both domestic and industrial usage [80,81].

The HyNTS program funded by National Grid envelopes several green hydrogen projects which seek to better transport hydrogen in the National Transmission System (NTS). In the NTS Hydrogen Injection project, the requirements and locations for setting up a new trial of hydrogen injection into the NTS have been evaluated. In the NTS project, the feasibility of transporting hydrogen in the NTS has already included pipeline case studies and relevant asset reviews. In the Hydrogen Deblending project, the hydrogen recovery technologies were reviewed. In Project Cavendish, a review has been conducted for Isle of Grain's hydrogen supply to London and the Southeast using existing infrastructure.

Moreover, in the Hydrogen Flow Loop project, metallurgy of the NTS pipe exposure to 30% hydrogen was evaluated for safety. In the meantime, the HyNTS has launched FutureGrid to demonstrate hydrogen transportation in the NTS and build a hydrogen test facility. While in phase 1, the FutureGrid project is building offline facilities which will share the gas distribution lines with the H21 program [82–84].

The H21 program, which also comprises a series of small projects, is funded by Ofgem and led by Northern Gas Networks. The goal of the H21 program is to transport 100% hydrogen in the current natural gas network with a few modifications. The viability study of supplying 100% hydrogen energy has been reported in the H21 Leeds City Gate in 2016. To fulfill the energy demands in Leeds, which is estimated to be around 6.4 TWh annually, a production capacity of 1025 MW SMR is required. The research data concludes that the current gas network can handle the conversion to hydrogen. One of the current H21 projects is the NIC Phase 2 project, which focuses on the operational and maintenance procedures of running a 100% hydrogen network. Two trials are being conducted, one in a newly constructed small-scale network, the other in an existing unoccupied network [85].

Other pure hydrogen projects in the UK include the Hy4Heat project and the HySpirits project led by the Department for Business, Energy & Industrial Strategy (BEIS), the Zero 2050 South Wales project led by the National Grid Electricity Transmission, and the Decarbonisation Pathways project led by the Energy Networks Association (ENA) [86–88].

3.2. Hydrogen Blending Projects in Europe

3.2.1. GRHYD

The GRHYD project is a French hydrogen blending project in Dunkerque city in northern France that was launched in 2014. The goal of GRHYD was to help France meet the goal of meeting 23% of its gross end-user energy consumption from renewable energy sources by 2020 [89]. To achieve these goals, GRHYD converted surplus energy generated from renewable energy into hydrogen and blended it with natural gas. The result of hydrogen blending was to increase the energy output of solar and wind power, at the same time reducing greenhouse emissions, demonstrating a Power-to-Gas (P2G) adaptation.

Two demonstration projects were developed under GRHYD. The first GRHYD demonstrator project focused on the residential energy sector. In a new residential neighborhood in Dunkerque, about 200 households were supplied with 20 vol% hydrogen blended natural gas. Hydrogen was produced by a PEM electrolyzer at a rate of 10 m^3 per hour based on the renewable energy generated through wind power. The Power-to-gas (P2G) technologies were well adapted in the process. Surplus wind energy was used to produce hydrogen, while excess hydrogen was stored in the form of metal hydrides [89].

The second GRHYD demonstration project focused on the transportation energy sector. Otherwise known as the Hythane Project, 6 vol% to 20 vol% hydrogen blending in natural gas were tested as fuels in 50 buses in the Dunkerque urban community. The challenge of the Hythane project was to operate a new type of refueling station for buses running on hydrogen blended fuel. Hydrogen was supplied by an electrolyzer using wind power generated electricity, which largely reduced carbon emissions in the process. At the refueling station, the generated hydrogen was blended into the compressed natural gas. The gas tanks of buses were filled with hydrogen blended natural gas, which typically took less than 15 min. The refueling station was in operation for two years and delivered 58,400 m^3 of Hythane without a single incident. The Hythane buses were equipped with a modified stoichiometric engine CURSOR 8 from IVECO. No adverse incidents were found in any Hythane bus over the 40,000 km driving distance throughout the study. Results from the Hythane project demonstrated an 8% reduction in carbon dioxide emissions and 10% reduction in NOx emissions compared to operating with natural gas. The total energy consumption of Hythane buses were 7% lower than natural gas buses. The overall cost of Hythane fuel was 0–20% lower than the cost of running buses with natural gas alone as a fuel [90]. In July 2017, the French government initiated the Climate Plan with a goal to transition from fossil fuels and achieve carbon neutrality by 2050 [91]. The success of GRHYD project showed the possibility of reaching carbon neutrality.

3.2.2. THyGA

The European Commission's 2030 Climate Target Plan aims to reduce at least 55% of greenhouse gas emission by 2030 and set a path to carbon neutrality by 2050 [92]. European countries developed the THyGA project (Testing Hydrogen Admixtures for Gas Appliances) to test the impact of hydrogen blending in natural gas on domestic and commercial end use applications. Studies were developed to test up to 100 residential and commercial end use appliances to set up a standard for manufacturers and users to follow. In addition, the goal of THyGA was to verify the safety of different hydrogen concentrations in natural gas and develop protocols in the hydrogen blending industry. The THyGA project was funded as part of the 2019 FCH 2 JU (Fuel Cells and Hydrogen Joint Undertaking) work program. Nine partners from national laboratories and manufacturers of gas appliances across six European countries worked together under THyGA for 30 months. The THyGA project was divided into six Work Packages (WPs): WP1, project management, focused on effective communications between nine partners; WP2, survey of gas utilization technologies, focused on compiling existing knowledge that can be shared among research groups; WP3 focused on experimental work, which consisted of testing about 100 sample appliances; WP4 focused on developing standards based on the results of the testing; WP5 focused on recommending risk mitigation procedures; WP6 focused on summarizing the project activities and results for communication, dissemination, and utilization [93].

Another focus of the THyGA project WP was hydrogen embrittlement. Numerous experiments were designed to fully understand and effectively prevent the damage hydrogen embrittlement can inflict on the pipeline system. These results will aid in the establishment of appropriate codes and standards for wide adoption of hydrogen blending in natural gas networks. Loading conditions, hydrogen charging, and pipeline materials conditions are three main factors that influence HE. Internal or external stress and strain can influence HE by altering the distribution and transport of hydrogen in the material's microstructure. An increase in hydrogen gas pressure can also increase the chance of HE. Studies found that at lower and higher temperatures, HE is less prominent while it is more significant at an ambient temperature. This is due to lower hydrogen diffusion and solubility under low temperature conditions while at higher temperatures, the alloys tend to be inherently more ductile, which minimizes the embrittlement effect [94].

Hydrogen embrittlement in common pipeline materials such as carbon steels, stainless steels, copper, brass, aluminum alloys and polyethylene has been closely studied. Low alloy steels are found to be most susceptible to HE. Studies also found that at low partial pressures of gas (30–50 mbar), up to 50% hydrogen content in natural gas does not present a significant problem to the metallic materials. Long term exposure of hydrogen gas does not deteriorate polymer materials like polyethylene (PE). In the leakage measurement studies, hydrogen is found to leak 2.5 times quicker than methane due to hydrogen's physical properties. Gas losses through hydrogen permeability in gas appliance components are negligible compared to leakages at seals, fittings, and threaded connection [94].

Upcoming experimental works are designed to check the effect of tightness of gas distribution network components on material deterioration, chemical compatibility and leakage of hydrogen blended natural gas. The goal of the test is to evaluate the leak-tightness of gas line network components. In the experiment, appliance components will not be dismounted, to mimic operating conditions. The first static check will monitor the presence of a leak by filling the system with gas mixture and observing the resulting pressure changes. In the dynamic check, a gas flux will be introduced in the system while maintaining a constant pressure level. Any change in the gas flow rate will indicate a leak. The static check is expected to take several months, while the dynamic test will take several hours.

3.2.3. WindGas Falkenhagen

Germany has had an early start for power-to-gas (P2G) projects across Europe. In 2013, EU Horizon 2020 sponsored three Store and Go projects. Among the three, the demonstration project located in Falkenhagen Germany was once the largest P2G project in Europe operating a 2 MW alkaline electrolyzer. The hydrogen output of this facility was 360 m^3/h utilizing excess energy generated from the wind turbines in the neighborhood. Hydrogen was injected into the local ONTRAS natural gas grid in August 2013 [95].

In 2017, a methanation plant was added to the facility of Falkenhagen. In a honeycomb catalytic reactor, synthetic natural gas (SNG) was produced from hydrogen and the carbon dioxide supplied by a nearby bio-ethanol plant. Synthetic natural gas compared to hydrogen has a broader market for applications. After a two-year review conducted by Store & Go, the WindGas Falkenhagen had reached 53% in P2G efficiency and 85% in methanation efficiency. It was found that the old alkaline electrolyzer was the main reason behind the low P2G efficiency. Therefore, the integration of a better electrolyzer in the system was proposed for improving the efficiency of the system in the future [96].

Based on the success of WindGas Falkenhagen, a new P2G project was established and started operation in Hamburg in 2015. The new electrolyzer used in WindGas Hamburg was a PEM electrolyzer with 1.5 MW power input. The hydrogen output of this facility was 290 m^3/h. Hydrogen produced was also injected into the local gas distribution network [97].

In September 2019, the German government agreed to initiate the Climate Action Programme 2030. The aim was to cease coal-fired electricity generation by 2038 and lay the foundation for Germany to reach carbon neutrality by 2050 [98].

3.3. Hydrogen Blending Projects in Australia

The Australian government announced its First Low Emission Technology Statement of 2020. The government promised direct investments in the low emission technology industry, including hydrogen blending technology [99]. Table 3 lists selective Australian renewable gas projects.

In May 2021, the Australian Gas Infrastructure Group (AGIG) in its biggest hydrogen production site started blending 5% hydrogen into its existing gas network which supplies more than 700 homes. The project known as "Hydrogen Park South Australia (Hyp SA)" aims to meet the net zero carbon target by 2050 for the region was setup by the Australian government. Hydrogen and biomethane are both considered carbon neutral gases. Blending hydrogen and eventually replacing natural gas with hydrogen was the pathway that AGIG has paved for reaching the net zero carbon goal. The hydrogen supplied in this project is generated from solar or wind energy powered electrolyzer (1.25 MW) located in Adelaide. The hydrogen production will be scaled up after the 10 MW electrolyzer is ready for deployment. Currently, the project is moving to phase 3, in which households will receive the 5% hydrogen blended natural gas delivered by tube trailers [100,101].

The AGIG has built a few other hydrogen projects across Australia. The Australian Hydrogen Centre, founded in 2019, has examined the feasibility of blending 10% hydrogen into the existing gas network. The center also researched the suitability of adopting 100% hydrogen in cooperation with other Australian government research centers. A similar research study, Western Australian Feasibility Study, was setup to investigate the suitability of introducing hydrogen into the Dampier to Bunbury pipeline [102].

In the HyP Gladstone project, which is currently under development, 10% hydrogen blend trials will be conducted to supply around 800 residential, commercial, and industrial customers in Gladstone located in central Queensland. In May 2021, HyP Murry Valley was funded by the Australian Renewable Energy Agency. In this project, green hydrogen produced from renewable energy sources will be injected into the natural gas network up to 10% by volume. The project will cover a total of 40,000 households in Wodonga and Albury in the Southeast of Australia by 2023 [103].

Jemena, Australia's largest P2G facility had a P2G demonstration based on green hydrogen applications in West Sydney. The hydrogen used in this project was generated from a 500 kW electrolyzer powered by solar and wind energy. One of the applications of hydrogen was injecting it into the gas network, which provided cooking, heating, and hot water to about 259 households. Additional hydrogen generated from P2G was used in gas engines or stored in fuel cell vehicle refueling stations. The project started in 2018 and it will last for 5 years. The goal of the project was to demonstrate the feasibility of hydrogen energy applications in current gas distribution and transmission networks in order to support future investments in renewable energy [103].

3.4. Hydrogen Blending Projects in Canada

Canada has also set up a goal of reaching net-zero greenhouse gas emissions by 2050 according to the Canadian Net-Zero Emissions Accountability Act passed in 2020 [104]. Two Canadian hydrogen blending projects are scheduled to enter field tests in 2021–2022. The hydrogen concentration in those two projects was low (2–5%). However, large communities will be affected in the pilot test, which will generate a lot of valuable data for future improvement.

In Fort Saskatchewan, Alta, Canadian Utilities initiated the largest hydrogen blending project in Canada in 2020. In the Fort Saskatchewan Blending Project, 5% hydrogen was proposed to be blended into a section of Fort Saskatchewan's residential natural gas network, affecting about 2000 customers. A total of $2.8 million funding came from Emission Reductions Alberta's Natural Gas Challenge. The hydrogen supplied in this project came from Canadian produced natural gas and the existing CCS facility in Alberta. The owner of Canadian Utilities, ATCO, will conduct feasibility and safety tests on the new and existing pipelines for delivering the hydrogen blended gas to customers. Customer site inspections are ongoing, while blended gas is expected to be introduced to the customers in the third quarter of 2022 [105,106].

In November 2020, Enbridge Gas and Cummins announced a new hydrogen blending project in the Markham area of Ontario. The Cummins-Enbridge Project has an existing P2G facility in Markham that was established in 2018 and is supported by the Canadian government. Hydrogen is produced from a 2.5 MW electrolyzer facility. The project aims to serve 3600 customers in Markham, supplying them 2% hydrogen blended natural gas, which will reduce up to 117 tons of carbon emissions every year. After successful completion of this project, Enbridge Gas will seek larger scaled hydrogen blending implementations in other regions of Canada [106,107].

3.5. Hydrogen Blending Projects in the United States

The idea of introducing hydrogen in natural gas has a long history in the United States. Hawaii Gas manufacturing SNG containing hydrogen can be traced back to the 1970′s. Today, the Campbell Industrial Park on the island of Oahu adds 12% hydrogen in its natural gas pipeline, which is the highest concentration of hydrogen in any commercial gas utility in the United States [108].

The largest hydrogen blending project proposed in the United States is the HyBlend Project, a hydrogen blending project led by the United States Department of Energy's National Renewable Energy Laboratory (NREL) along with five more national laboratories to facilitate hydrogen blending in natural gas pipelines that was started in October 2021 [105]. The project is funded by the Office of Energy Efficiency and Renewable Energy (EERE) and over 22 industry participants. As a new project, several proposed tasks were outlined to meet the goal of safely transportation and application of hydrogen blended natural gas.

The HyBlend project has an aggressive timetable with key tasks. The first task is to check hydrogen compatibility in piping materials and pipelines. Sandia National Laboratories (SNL) and Pacific Northwest National Laboratory (PNLL) lead the research task of investigating the life expectancy of both metal and polymer pipeline materials that are exposed to hydrogen. These two national labs will also be cooperating with Hydrogen

Materials Compatibility Consortium (H-Mat), which has over 20 partners in industry and academia researching hydrogen compatibility with metals and polymers. The second task is conducting life-cycle analyses, led by Argonne National Laboratory (ANL), to analyze the life-cycle emissions of hydrogen-natural gas blends using the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model. The last task is conducting a techno-economic analysis. Costs and opportunities for production and blending of hydrogen within the natural gas network will be quantified by NREL.

Joint research efforts between university and industry, especially, gas utilities are being developed in the US hydrogen blending space. The Institute of Gas Innovation and Technology (I-GIT), initially co-founded by National Grid and Stony Brook University in 2017, is one of the HyBlend project research facilities with both academic and industrial support. Ongoing studies at I-GIT are focused on hydrogen pipeline compatibility, lifecycle, and techno-economic analysis of utilities' existing natural gas infrastructure. The goal of the hydrogen blending research is to assist gas utilities in New York to reach their goal of achieving net zero carbon by 2050 following the guidelines of the New York State's Climate Leadership and Community Protection Act (CLCPA) [109]. National Grid has initiated a blending demonstration project in partnership with Town of Hempstead in December 2021. The project will build on the verification of tests led by I-GIT and expand the existing green hydrogen facility at the Department of Conservation and Waterways Energy Park in Lido Beach. This project will blend green hydrogen up to 20 mol% into the existing gas distribution system, to heat approximately 804 homes and fuel 10 municipal vehicles.

Another example of a hydrogen blending demonstration study is on the west coast of the United States, a collaboration between Southern California Gas Co. (SoCalGas) and San Diego Gas and Electric (SDG&E), initiated in November 2020. The goal of the of the project is to inject hydrogen into the natural gas grid utilizing the latest P2G technology co-developed by SoCalGas, the National Fuel Cell Research Center, and University of California, Irvine. Initially, the SoCalGas project plans to test a 1% hydrogen blend and then move gradually to a 20% hydrogen blend. The first phase of the project was scheduled for early 2021 in the SoCalGas' service territory with a focus on the PE distribution system. The next stage of the research will move to the SDG&E's service territory testing mixed PE and steel distribution networks [110]. A summary of the ongoing hydrogen projects in North American, led by gas utilities, is shown in Table 4. The SoCalGas hydrogen blending project was a step toward to attain the goal set up by the Californian Cap-and-Trade Program, which was to reduce the carbon emissions in California back to the 1990 levels by 2020 [111].

In Hawaii, the number of hydrogen related projects are growing every year, playing a major role in meeting the Hawaii Clean Energy Initiative's (HCEI) goal to replace 70% of Hawaii's energy demand with renewable energy before 2030 [112]. Hawaii Gas, in partnership with Hawaii Center for Advanced Transportation Technologies (HCATT), US Hybrid Corporation, and Hawaii Natural Energy Institute (HNEI), initiated several hydrogen related projects in local communities. One example is the development of a pilot study of hydrogen powered cars partnered with General Motors [109]. Servo Pacific built several hydrogen fueling stations in Mapunapuna, Honolulu targeting hydrogen fueled cars in the neighborhood. The HCATT has a project in Joint Base Pearl Harbor-Hickam to generate electricity and produce hydrogen from waste at the base. Hawaii Blue Planet Research has demonstrated a hydrogen energy storage system utilizing 100% renewable microgrid [113].

Table 2. World Hydrogen Blending Projects.

Project	Country	Year	Blending Vol%	Trial/Project Size	Reference
HyDeploy	UK	2019	20	1500 residentials	[74–76]
East Neuk Power	UK	2020	20	15 GWh energy annually	[77]
Aberdeen Vision	UK	2020	2–20	300 residentials	[78,79]
HyNet Northwest	UK	2021	100	30 TWh energy annually	[80,81]
HyNTS Hydrogen Flow Loop	UK	2021	30	-	[82–84]
H21	UK	2018	100	6.4 TWh energy annually	[85]
Hy4Heat	UK	2018	100	-	[86–88]
HySpirit	UK	2019	100	-	[86–88]
Zero 2050 South Wale	UK	2020	100	-	[86–88]
Decarbonisation Pathway	UK	2020	100	-	[86–88]
GRHYD	France	2014	20	200 residentials	[89]
THyGA	EU	2019	10–100	100 residentials and commercials	[93,94]
WindGas Falkenhagen	Germany	2013	2	-	[95,96]
WindGas Hamburg	Germany	2015	2	-	[97]
HyP SA	Australia	2021	5	700 residentials	[100,101]
HyP Gladstone	Australia		10	800 residentials and industrials	[103]
HyP Murry Valley	Australia	2021	10	40,000 residentials	[103]
Jemena West Sydney	Australia	2018	2	259 residentials	[103]
Fort Saskatchewan	Canada	2020	5	2000 residentials	[105,106]
Cummins-Enbridge	Canada	2018	2	3600 residentials	[106,107]
HyBlend	USA	2021	1–30	-	[109,110]
SoCalGas	USA	2020	1–20	-	[111]

Table 3. Australian renewable gas projects [103].

Locations	Projects
West Australia	Clean Energy Innovation Park Western Australian Feasibility Study
South Australia	Hydrogen Park South Australia
Southeast Australia	Hydrogen Park Murray Valley Australian Hydrogen Centre
Northeast Australia	Hydrogen Park Gladstone

Table 4. North American gas utilities hydrogen projects [114].

Locations	Projects
Eugene, Oregon	NW Natural
Salt Lake City, Utah	Dominion Energy
Southern California	SoCalGas and SDG&E
Austin, Texas	SoCalGas and ONE Gas
Twin Cities region, Minnesota	CenterPoint Energy
Ontario, Canada	Enbridge Gas
Stony Brook, New York	National Grid
Howell, New Jersey	New Jersey Resources

4. Conclusions and Perspectives

By introducing hydrogen (esp., green hydrogen that is generated from renewable sources such as solar and wind) in methane-hydrogen blends, in many end-use applications such as engines, oven burners, boilers, stoves, and fuel cells, there is potential for significantly reducing green-house gases, SOx, NOx, and particulates.

Recognizing the benefits of hydrogen-natural gas blends and the opportunity for a gradual transition from fossil fuel-based economy to a hydrogen economy through the repurposing of existing natural gas networks for hydrogen storage and transport, governments around the world, are supporting demonstration projects such as HyDeploy, GRHYD, THyGA, HyBlend, and more, all of which are seeking a cost-effective pathway for meeting the carbon reduction goal in the coming decades. In order for this transition to the hydrogen economy to be successful, a comprehensive understanding of the issues and challenges associated with hydrogen from production to storage, transport and end-use is required by a wide set of stakeholders from research institutions, industry and policy makers.

This review provides an updated perspective of the current state-of-the-art in the areas of large-scale transport and end-use of hydrogen-methane gas blends.

Despite the advantages that hydrogen brings to the energy system, the property differences between natural gas and methane-hydrogen mixtures (such as density, viscosity, phase interactions and energy densities) are also the primary reasons for major safety concerns, over pressurization and leakage in pipelines of which there is a chance of incidence in hydrogen blended gas pipelines. Long term hydrogen embrittlement is also a risk in pipelines that transport hydrogen. While the short-term hydrogen embrittlement effect that was investigated in the HyDeploy project showed essentially no detectable degradation in the metal tensile strength, long term effects of exposure to hydrogen under operating conditions of gas pressures, pipeline stresses and impurities in the gases on metal and polymer pipelines need to be assessed and that is the focus of several ongoing studies such as HyBlend. Particularly, with natural gas networks comprised of steels with various vintages that have compositions and impurities, there is an on-going effort to assess the suitability of such materials for hydrogen storage and transport. As failures due to hydrogen embrittlement can be catastrophic with the potential to endanger safety of operators and end users, a comprehensive understanding of the hydrogen embrittlement and preventive technologies are required for large-scale deployment and long-term transport of hydrogen through pipelines.

The current natural gas pipeline system consists of gathering, transmission, and distribution lines, each with varying materials, in-service age, operating conditions, and equipment size. Hydrogen blending is expected to take place in both transmission and distribution lines that connect commercial and residential end users. Pressure reduction is one of the drawbacks that hydrogen blending brings to the cost dynamics of blended gas transport. In general, more energy is needed to transport the blended gas (compared to pure natural gas) to deliver the blended gas of comparable energy density at the appropriate flow-rate conditions to the end users. However, by modifying the pressures and flow rates, the increased cost of transporting hydrogen can be mitigated. Hence, in addition to the scientific studies, techno-economic analyses (as conducted in the HyBlend project) are useful for understanding the energy transportation efficiency and estimating the true cost of delivery of hydrogen blended natural gas.

In summary, based on our existing knowledge reviewed in this manuscript, four key challenges with hydrogen blends in the existing gas networks are noted. These are: (1) Increased combustion temperatures and laminar flame speeds of gas blends may require design modifications to certain end-use appliances, such as engines and burners; (2) Lower mass flow and energy transport rates in gas pipelines transporting blends will require additional compressors (thus more energy); (3) Increased risk of leakage, thus, potential explosions with higher hydrogen content gas blends will require new safety codes and standards; (4) The potential for hydrogen induced corrosion and embrittlement with long term exposure to hydrogen in pipelines.

Overall, this review illustrates that scientific studies are targeted towards mitigating the aforementioned concerns to enhance pipeline and end-use application safety, while techno-economic studies are directed towards identifying cost-effective implementation pathways for developing hydrogen blending roadmaps for gas networks and for shaping the global adaptation of the "Hydrogen Economy". This review covers only a few key areas in this expanding field and touches just methane-hydrogen related issues in a pipeline (confined space). It is expected that several specific-topic related reviews would follow to allow companies to deploy blending centric technologies.

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Abbreviations

AGIG	Australian Gas Infrastructure Group
ANL	Argonne National Laboratory
API	American Petroleum Institute
ATEX	Atmospheric Explosion
BCC	Body-Centered Cube
BEIS	UK Department for Business, Energy & Industrial Strategy
BTU	British Thermal Unit. 1 BTU = 1055 J
CAI	Controlled Auto Ignition
CCS	Carbon Capture and Storage
CFD	Computational Fluid Dynamics
CLCPA	New York State's Climate Leadership and Community Protection Act
DDT	Deflagration to Detonation Transition
ENA	Energy Networks Association
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation
HAZ	Heat-Affected Zone
HCATT	Hawaii Center for Advanced Transportation Technologies
HCEI	Hawaii Clean Energy Initiative
HE	Hydrogen Embrittlement
HIFLD	the United States Homeland Infrastructure Foundation-Level Data
H-Mat	Hydrogen Materials Compatibility Consortium
HNEI	Hawaii Natural Energy Institute
HSE	United Kingdom Health & Safety Executive
HSS	High Strength Steels
ICP-OES	Inductively Coupled Plasma—Optical Emission Spectrometry
I-GIT	Institute of Gas Innovation and Technology
LFL	Low Flammability Limit
LHV	Lower Heating Value. LHV(H_2) = 120,000 kJ/kg. LHV(CH_4) = 50,000 kJ/kg
NOx	Nitrogen Oxides
NREL	The United States National Renewable Energy Laboratory
NTS	National Transmission System
EERE	The United States Energy Efficiency and Renewable Energy office
EOS	Equation of State
EST	Energy Specific Toll
P2G	Power-to-Gas

PEM	Polymer Electrolyte Membrane
PE	Polyethylene
PNLL	Pacific Northwest National Laboratory
QRA	Quantitative Risk Assessment
SDG&E	San Diego Gas and Electric
SI Engine	Spark-Ignition Engine
SMR	Steam-Methane Reforming
SNG	Synthetic Natural Gas
SNL	The United States Sandia National Laboratories
SoCalGas	Southern California Gas Co.
SOEC	Solid Oxide Electrolysis Cell
SOx	Sulphur Oxides
SRK	Soave-Redlich-Kwong
RHEED	Reflection High-Energy Electron Diffraction
XPS	X-ray Photoelectron Spectroscopy

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