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CHALLENGES TO INDUSTRY

A review of challenges with using the natural gas system for hydrogen

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Abstract

Hydrogen, as an energy carrier, is attractive to many stakeholders based on the assumption that the extensive global network of natural gas infrastructure can be repurposed to transport hydrogen as part of a zero-carbon energy future. Therefore, utility companies and governments are rapidly advancing efforts to pilot blending low-carbon hydrogen into existing natural gas systems, many with the goal of eventually shifting to pure hydrogen. However, hydrogen has fundamentally different physical and chemical properties to natural gas, with major consequences for safety, energy supply, climate, and cost. We evaluate the suitability of using existing natural gas infrastructure for distribution of hydrogen. We summarize differences between hydrogen and natural gas, assess the latest science and engineering of each component of the natural gas value chain for hydrogen distribution, and discuss proposed solutions for building an effective hydrogen value chain. We find that every value chain component is challenged by reuse. Hydrogen blending can circumvent many challenges but offers only a small reduction in greenhouse gas emissions due to hydrogen's low volumetric energy density. Furthermore, a transition to pure hydrogen is not possible without significant retrofits and replacements. Even if technical and economic barriers are overcome, serious safety and environmental risks remain.

KEYWORDS

alternative fuels, decarbonization, energy, hydrogen, natural gas

1 | INTRODUCTION

Natural gas is an integral component of the world's current energy system, accounting for around a quarter of today's final energy demand globally.[1] Natural gas is principally comprised of methane (CH_4), with smaller amounts of mostly ethane and carbon dioxide (CO_2)—all of fossil origin. Natural gas combustion is estimated to account for around 30% of annual global anthropogenic CO_2 emissions.[2] Furthermore, a growing body of research has revealed the extent of gas lost to the atmosphere throughout the supply chain, which is estimated to account for 12% of annual global anthropogenic methane emissions.[3] Together, CO_2 and CH_4 are responsible for around 75% of today's gross warming relative to the beginning of the industrial revolution.[4] Whereas experts suggest that we have the technologies available to cut CH_4 emissions from oil and gas operations by 75%,[3] a transition away from fossil fuels and their combustion, including natural gas, is needed to achieve climate goals.[5] Therefore, an obvious way to maintain beneficial use of the extensive and valuable global network of natural gas infrastructure during the impending energy transition would require switching to a gas/gas mixture that does not generate greenhouse gas (GHG) emissions when combusted.

Hydrogen (H_2) has emerged as a natural gas replacement, because it can release energy without associated carbon dioxide emissions. The chemical energy stored in the hydrogen to hydrogen bond can be converted to either heat through combustion or electricity in a fuel cell with no CO_2 emissions: processes that humans have been employing for more than 100 years.[6] H_2 cannot currently be considered an energy source like natural gas, because it is being produced through methods such as electrolysis or steam reforming.[7] There are numerous techniques available to manufacture hydrogen from feedstock molecules, including natural gas but also water. Currently, 99% of dedicated H_2 production relies on fossil fuels without carbon capture,[3] emitting over 900 million metric tonnes of CO_2 into the atmosphere annually.[3] There are more than a 1000 proposed projects aimed at scaling up zero- and low-carbon hydrogen production processes globally.[8] There are challenges associated with each "clean" hydrogen production method as well—and no method is universally beneficial to the climate.[9–12] For example, renewable energy displacement or high methane emissions can make hydrogen applications worse for the climate in the near-term than the fossil fuel systems they are replacing.[13]

Although reusing natural gas infrastructure for hydrogen is an appealing proposition, its feasibility rests on the suitability of the existing gas network for hydrogen gas. Decades ago, gas mixtures made by gasification of either coal or petroleum—known as "town gas"—contained high concentrations (up to 50% by volume) of H_2,[14] and were piped into homes. Therefore, the distribution infrastructure could technically tolerate high levels of hydrogen. Although gas produced by gasification of petroleum naphtha and natural gas is still used in locations like Singapore and Hong Kong, this method has been abandoned in most of the world for safer options (natural gas), which do not contain toxic carbon monoxide. Therefore, most gas networks today are almost entirely designed for fossil gas mixtures that are primarily comprising methane (75% to 90%+ by volume, containing very little if any H_2). Material selection, system attributes, storage systems, appliances and device design, and so on were designed, tested, and optimized specifically for the characteristics of natural gas and not for those of H_2. The fundamental differences in physical and chemical properties of H_2 and CH_4 are quite large, leading to challenges with respect to safety, energy supply, climate impacts, and cost.

In the following sections, we address the practicality, risks, and remaining data gaps of using H_2 in existing natural gas infrastructure by (1) contrasting physical and chemical properties between H_2 and CH_4; (2) describing how these differences affect each component of the existing natural gas system value chain; (3) discussing potential strategies to mitigate issues; and (4) the challenges associated with implementing such solutions.

2 | CONSTRASTING PROPERTIES OF HYDROGEN AND NATURAL GAS

Although both colorless and odorless gases at standard temperature and pressure, H_2 and CH_4 are very different gases both physically and chemically (see Table 1). These differences present many challenges when considering the use of natural gas infrastructure for H_2, which are further discussed in Section 3. In addition, while CH_4 in the atmosphere absorbs radiation whereas H_2 does not, both can be oxidized leading to perturbations to atmospheric chemistry in ways that lead to increases in other GHGs.

2.1 | Physical

There are two key physical differences between H_2 and CH_4 that relate to their molecular sizes and liquid phase temperatures. First, hydrogen is the smallest and lightest element on the periodic table. A molecule of hydrogen—consisting of two hydrogen atoms—is therefore the smallest and lightest molecule. H_2's weight and density is one-eighth that of CH_4 and its diffusivity in air is around three times higher (see Table 1). This means that H_2 can more rapidly leak from infrastructure, permeate through materials, and rise and accumulate at high points in enclosed spaces.[15]

Second, the temperatures at which H_2 and CH_4 can be converted into a liquid, which can be useful as a storage and transport mechanism, are −253°C and −162°C at atmospheric pressure, respectively. Thus, much more energy is needed to convert H_2 gas into a liquid and it is more likely to incur H_2 losses through evaporation given the high temperature difference between the liquid and the surrounding environment.

TABLE 1 Characteristics of hydrogen compared to natural gas (methane) and their implications.

	Property	Hydrogen (H_2)	Methane (CH_4)	Hydrogen compared to natural gas (mostly CH_4)	Implications of H_2 compared to natural gas
Physical					
Size	Molecular weight, g/mol	2.106	16.04	~8× lighter	Permeates faster from gaskets, seals, plastic pipes, and other "soft" materials
Density	Density (NTP), kg/m^3	0.08375	0.668	~8× lower density	Rises and accumulates in enclosed spaces
Diffusion	Diffusion coefficient in air, m^2/s (20°C)	7.56E−05	2.21E−05	Higher diffusivity	Overall tendency to leak at a greater extent through intact materials of construction, seals, and piping joints
	Diffusion coefficient in water, m^2/s (20°C)	4.58E−09	1.62E−09		
Liquid phase	Temperature at atmospheric pressure (°C)	−253	−162	~100°C colder	Requires much more energy to convert to liquid state; more rapid boil-off
Chemical					
Chemistry	Reactivity	H-H bond symmetry	C-H bond asymmetry	Formation of partial bonds which lower activation energy	Accelerates fatigue cracking and reduces fracture toughness of steels
					May be depleted in underground storage
Ignition	Explosive limits, % - %, by volume	4–75	5.3–15	Higher explosive limit	Higher fire risk
	Ignition energy mJ	20	290	Lower ignition energy	
Flame	Maximum flame speed, m/s	0.34	2.9	~8× faster flame speed	Lower flame stability in burners, risk of flash-back
	Flame color	Invisible in daylight	Blue	Lower visibility	Harder to detect
	Adiabatic flame temperature in air,°C	2210	1950	Higher temperature	More NO_x produced
Calorific value	Higher heating value, MJ/m^3	12.7	39.8	1/3 of natural gas by volume	3× gas velocity needed to deliver the same amount of heat energy
					3× energy needed to compress gas
					3× volumetric gas flow measurements needed
					3× less line pack storage

2.2 | Chemical

There are four key chemical differences between H_2 and CH_4 that relate to their reactivity, flammability, flame properties, and energy density. First, H_2 is far more reactive than CH_4. CH_4 is the least reactive of the hydrocarbons, and whereas H_2's H-H bond has about the same bond energy as the C-H bond in CH_4, H_2's bond symmetry relative to CH_4 allows the formation of partial bonds which lower the activation energy of reactions with other molecules relative to methane.[16] This means that H_2 can more easily react with some construction materials (e.g., cement) and it can be harder to store H_2 underground than CH_4.

Second, the ignition properties of H_2 relative to CH_4 make it more flammable. Hydrogen has a much wider range between lower and upper flammability limits than natural gas (4%–75% for H_2 vs. 5.3%–15% for CH_4 and 5%–15.6% for natural gas).[16,17] H_2 leakage is, therefore, more likely to reach a potential source of ignition within the range of ignitable mixture concentrations than similarly sized leaks of natural gas. H_2 also has a considerably lower ignition energy than CH_4, meaning that it is considerably easier to ignite accidentally via arcs and sparks from electrical devices.[17]

Third, H_2's flame properties make it more dangerous than CH_4. H_2's laminar flame speed is about eight times that of CH_4.[18] Flame speed affects flame stability in burners, the risk of flashback, and overpressure, which may be encountered during a deflagration event such as the ignition of gas leaked into a confined space. Flames of pure H_2 are also very low in visible light emissions, making flame detection more difficult. Finally, H_2's adiabatic flame temperature is higher than that of CH_4. This gives it the potential to generate more nitrogen oxides (NO_x) for given combustion conditions.[17,19]

Fourth, H_2 has a very high energy density per unit mass, but per unit volume, its energy density is about one-third that of a typical pipeline gas. This means that much less energy is transmitted, distributed, and stored in the same volume of H_2 versus natural gas.

2.3 | Atmospheric

CH_4 is an infrared-absorbing GHG, whereas H_2 is not. However, both gases react with hydroxyl radicals in the atmosphere, leading to increased concentrations of other GHGs and, therefore, indirectly causing warming. For CH_4, the main sink of emissions is atmospheric oxidation with the hydroxyl radical that on average takes about a decade, leading to the formation of the GHGs tropospheric ozone, stratospheric water vapor, and carbon dioxide.[20] For H_2, ~70% is taken up by microbial communities in the soil and the remaining ~30% take about 2 years to be oxidized by the hydroxyl radical, leading to the formation of tropospheric ozone and stratospheric water vapor.[21,22] An additional warming effect from H_2 emitted to the atmosphere is that less hydroxyl is available to react with CH_4, thereby increasing its residence time in the atmosphere. Consequently, current assessments of hydrogen's global warming potential suggest that H_2 can cause around ~12 times more warming than carbon dioxide (CO_2) over a 100-year period following emissions of equal mass, and ~37 times more warming over a 20-year period.[21] CH_4's warming potency (from direct and indirect warming effects) is around ~30 and ~80 times that of CO_2 over 100 and 20 years, respectively.[4]

3 | IMPLICATIONS ACROSS THE NATURAL GAS VALUE CHAIN

The physical and chemical differences between H_2 and CH_4 are critical to the suitability of using several components of existing natural gas infrastructure for H_2, and contribute to safety, energy supply, climate, and cost risks (see Figure 1). Although there are solutions to mitigate some of these risks, they too are often associated with new risks and challenges.

3.1 | Production

Natural gas is produced from wells and fed via gathering lines to processing plants, where a gas mixture meeting pipeline specifications is produced. Purification processes vary by gas composition but often include removal in part or in total of gaseous higher-carbon hydrocarbons, butane, propane, ethane, in addition to sulfur compounds, mercury, carbon dioxide, water, and rarely, helium. Sometimes, nitrogen is added to reduce the energy content.

Some natural gas production can be expected in a decarbonized future, for use in producing chemicals like ethylene and propylene. However, given that most gas is burned rather than used as a chemical feedstock,[23] most natural gas wells, gathering lines, and processing plant infrastructure would only have very limited use in a decarbonized world as peaking capacity to complement renewable power and storage (see Figure 2). Reuse of some components may be possible, with scraps taken and repurposed. Therefore, new infrastructure would be required to scale up hydrogen production facilities and then transport the hydrogen to the natural gas

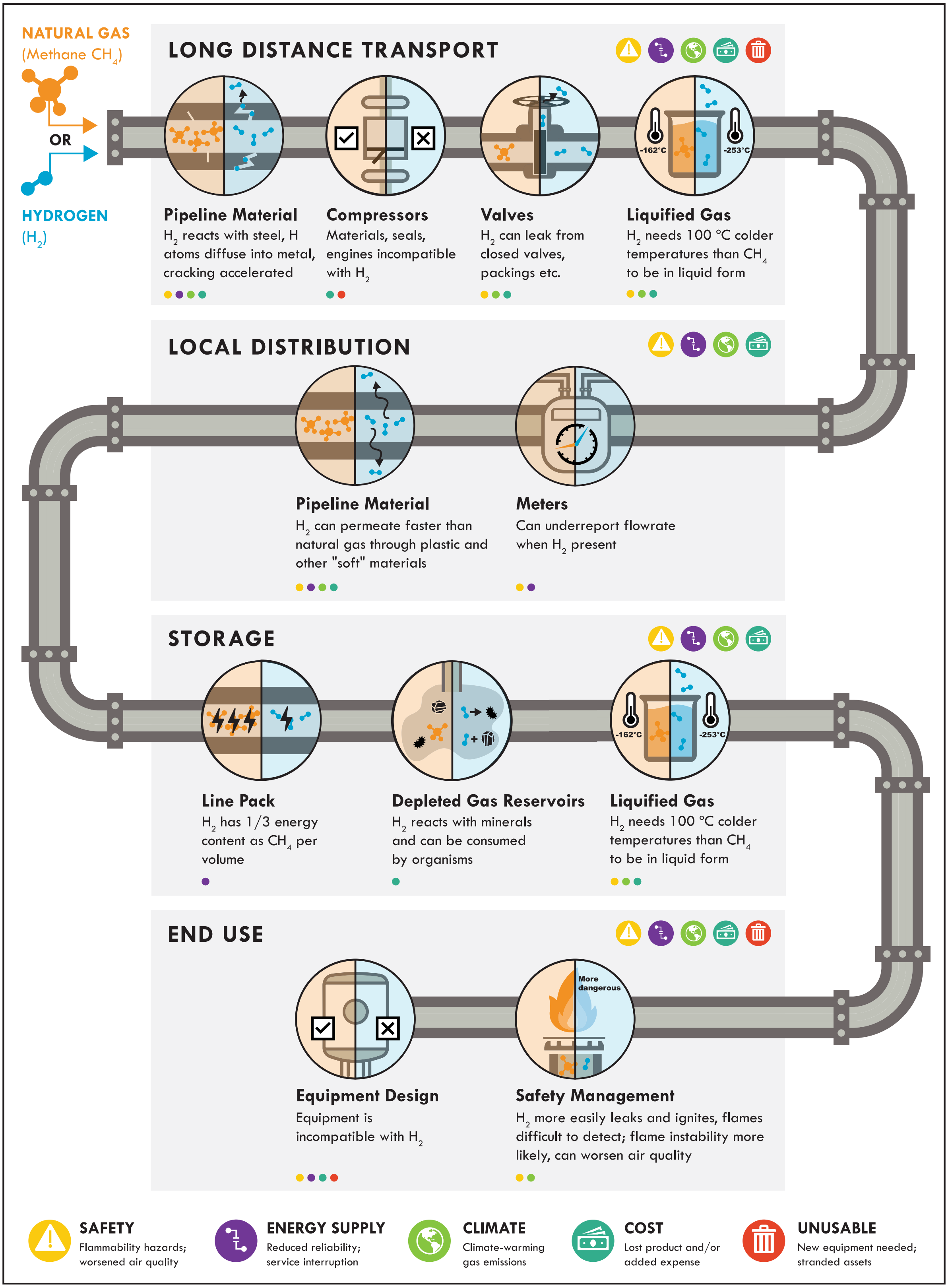

FIGURE 1 Challenges and risks with using existing natural gas system for pure hydrogen service.

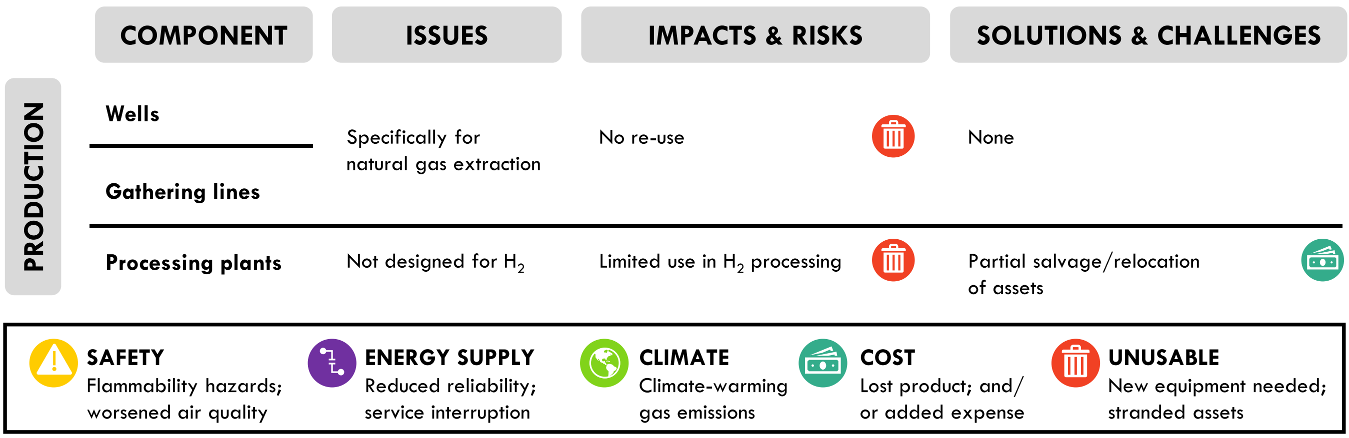

FIGURE 2 Existing natural gas production system suitability for pure hydrogen.

transmission infrastructure. However, although natural gas processing plants are not designed for H_2, it is possible that some parts may be salvaged and relocated.

3.2 | Long-distance transport

Natural gas from processing plants is often transported long distances via transmission pipelines or transported in its liquified form, when crossing oceans. Transmission pipelines typically operate at considerable pressure (50–150 bar or 5–15 MPa); are constructed from high yield strength grades of carbon/low alloy steel; have exterior coatings and electrochemical protection to reduce pipe corrosion; and are often buried (or subsea) for physical protection.[24] Interior linings are sometimes used. The pipes are sized for pressure drops on the order of 5 psi per mile (20 kPa/km), with compressor stations at regular intervals to maintain pressure. These compressors often use centrifugal-type or reciprocating-type machines and are powered by gas turbines or engines fueled by the gas in the pipeline, and in some cases electric motor-driven.[24,25]

There are several issues with using the current natural gas transmission system for H_2, relating to pipeline material, line capacity, valves, and compressors (see Figure 3).[26–29] Hydrogen accelerated fatigue cracking (HAFC) is the primary concern in converting existing natural gas pipelines for H_2.[30–32] In high-yield strength steels commonly used in gas transmission pipelines, exposure to molecular hydrogen combined with cyclic stress, initiated at manufacturing or welding flaws or corrosion points in the piping system, increases the growth rate of cracks. The process, known as HAFC, occurs because hydrogen atoms diffuse into the steel.[33] The cracks may ultimately extend through the wall of the pipe, causing it to leak or burst.[34] The hydrogen atoms can also recombine into molecular hydrogen gas at defects in the steel.[35] Low-yield-strength steel pipes are not particularly susceptible to fatigue cracking unless both temperature and the partial pressure of hydrogen are quite high.[30,36]

Recent, extensive testing of typical pipeline materials in Europe demonstrates both acceleration of fatigue cracking and reduction in fracture toughness when hydrogen is used, but the impacts vary widely depending on the material.[36] Welds and their heat-affected zones, as well as manufacturing or fabrication defects in the pipe increase vulnerability by serving as crack initiation sites.[37] This issue has been known for decades.

Pipe failure is of concern due to potential asphyxiation and fire and explosion.[38–40] Because natural gas pipes are usually buried, external inspections are difficult and internal inspections are largely relied upon to verify the integrity of the pipe material. Consequently, there is a considerable risk of premature failure if natural gas pipes are re-purposed for H_2 service. There are, however, several solutions that have been suggested, but none are without additional challenges.

First, hydrogen could be "blended" with natural gas below a certain threshold so that the partial pressure of hydrogen is limited and HAFC risk is reduced.[41] However, this significantly limits the decarbonization potential of using hydrogen, because it is not safe to pursue higher blending rates without undertaking retrofits or complete replacement of pipes. Even with small percentage admixtures of molecular hydrogen in high pressure natural gas pipes made of high-yield strength carbon steels it is expected that considerable acceleration of fatigue cracking, by as much as 30-fold, will occur with fracture resistance of the piping material reduced by as much as 50%.[34]

Second, it is sometimes possible to install a liner or coating into a natural gas pipe to protect it against

LONG-DISTANCE TRANSPORT

COMPONENT	ISSUES	IMPACTS & RISKS	SOLUTIONS & CHALLENGES
Pipeline material	H_2 can dissociate into atomic H on steel surfaces from corrosion mechanisms, electroplating, or the decomposition of water from damp flux materials during welding	Reduced ductility, fracture toughness and fatigue resistance lead to accelerated cracking, causing leakage and potential mechanical failure	1. Limit amount of H_2 but limited decarbonization potential 2. Add liner/coating but more research needed; difficult to access/ inspect because most pipes underground; leakage; service interruption; expensive 3. Reduce operating pressure but reduces energy supply, line pack unless new pipe added in parallel 4. Replace pipe but service interruption; expensive
Line capacity	H_2 has 1/3 energy content as natural gas per volume; if design pressure de-rated, further reduction in energy content	At least 3x less energy delivered to consumers	1. Limit amount of H_2 but limited decarbonization potential 2. Increase volumetric flowrate by 3x but then compressors require 3x energy
Compressors	Materials of construction, seals, engines, not designed for H_2	Incompatible equipment	1. Limit amount of H_2 but limited decarbonization potential 2. Replace compressors but inconvenient, expensive
	Changes in operational pressure or flowrate to resolve other issues requires more energy	More input energy required to compress H_2	1. More compressors but inconvenient, expensive 2. Shorter distances between compressors but inconvenient 3. More energy input but takes energy away from other uses
Valves	Not designed for H_2	H_2 can leak from closed valves, packings etc.	Replacements required
Liquified gas	Requires extremely low temperatures	Energy intensive and leakage	Specialized infrastructure is required

SAFETY Flammability hazards; worsened air quality

ENERGY SUPPLY Reduced reliability; service interruption

CLIMATE Climate-warming gas emissions

COST Lost product; and/ or added expense

UNUSABLE New equipment needed; stranded assets

FIGURE 3 Existing natural gas transmission system suitability for pure hydrogen.

corrosion and erosion, leading some to suggest that liners or coatings may provide a means to protect existing gas pipelines against HAFC associated with H_2.[33,42,43] However, this can be challenging both technically and logistically. Furthermore, H_2 permeates through nonmetallic materials and, over time, even permeates through intact metallic materials.[44] Thus, the suite of hydrogen-impermeable materials to choose from is extremely limited. Moreover, installing a liner in an existing buried line is very difficult to undertake effectively and would require shutting down the pipe for an extended period of time. Because permeation is likely inevitable, the space between the liner and the inner diameter of the pipe would need to be vented at numerous points along the pipeline, or else the cracking risk would not be prevented. The resulting H_2 leakage/venting also represents a flammability hazard and emits climate-warming H_2 into the atmosphere. Research into suitable options for the interior protection of gas pipelines against H_2-induced damage is underway, with recent developments identifying graphene and MXene as promising.[43] However, liners are difficult to install, control, and inspect regardless of material.

Third, cyclic stress amplitude can be reduced and HAFC might be delayed by operating piping systems at constant pressure, but practically it may not be possible, and other cyclic stresses (from vibration, soil movements, thermal expansion, and so on) will continue to pose a risk of fatigue cracking. Repurposing existing gas pipelines to carry H_2 would also often require de-rating the design pressure to as little as half to one-third of the original due to design codes and standards (see Supporting Information for details).[42] A reduction in design pressure of this magnitude represents a very significant reduction in pipeline energy-carrying capacity and also diminishes the “line pack” (i.e., the energy stored in the form of gas compressed above its delivery pressure in the gas network; discussed further in Section 3.4).

There are safe materials available for construction of new, purpose-built H_2 pipelines.[30,45] Purpose-built industrial hydrogen pipelines made from mild steels, lower strength steels or high yield strength steels that were designed and fabricated for use with hydrogen have been operating for decades.[45,46] The key is design pressure determinations, materials selection, nondestructive examinations, welding methods, and testing all focused on H_2 applications. These pipelines are operated differently than natural gas pipelines, operating at low and near constant pressures (less than about 65 bar(g) or 6.5 MPa).

Regardless of potential modifications and replacement, an additional transmission challenge for hydrogen is pipeline capacity. With H_2's energy density per unit volume at one-third that of a typical natural gas and the desirability of operating hydrogen pipelines at low pressure, the ability to move large amounts of hydrogen using existing pipelines is limited. For example, the amount of energy that can be transmitted by hydrogen compared to natural gas would be one ninth if derating pressure by on third and having one-third of the calorific value.

Alternatively, the volumetric flowrate could be increased so that a given gas transmission pipeline carrying hydrogen could deliver the same number of joules per hour of heat energy as existing natural gas pipelines.[47–49] However, an increase in volumetric flowrate depends on compressors being able to overcome frictional losses, which would require a lot of energy.[47–49] The mechanical energy to compress one gas relative to another is roughly inversely proportional to its molecular weight, which at constant temperature and pressure is proportional to the volumetric flow at a given compression ratio (see Supporting Information). Given that H_2 would need to flow in piping at roughly three times the volumetric flowrate of natural gas to deliver the same amount of energy, hydrogen compressors would require at least three times as much energy as those used for natural gas. Compression energy requirements would be increased further if the design pressure of the piping must also be reduced; a line operating at reduced pressure would have reduced energy carrying capacity, and the pressure loss per unit length would require compression to a greater compression ratio at each compressor station. This would require proportionately more compressor input energy per delivered joule of heat energy in the transmitted gas, thus, undercutting the net climate benefits of delivered hydrogen. (See calculations in Supporting Information.)

Although the energy efficiency impact and cost may be significant, the need to replace all compressors in existing transmission systems with larger machines of considerably higher power and suction displacement would require a significant investment and the capacity to provide such compressors. Existing compressors are often made of materials of construction (high strength steels, and so on) and can have seals, and so on, incompatible with H_2, and any engines previously running on gas would need replacement or significant modification to operate with pure H_2.[50] In the absence of valve replacement hydrogen can leak from existing closed valves, packings, and so on, which leads to safety hazards, lost product, and climate-warming emissions.[50,51]

3.3 | Local distribution

Once delivered to the “city gate,” natural gas is distributed to individual users via an extensive network of buried piping operating at medium to low pressures. These pipelines are made of a variety of materials ranging from mild steel to cast iron to high-density polyethylene (HDPE).

The lower pressure in the distribution network, the operation of piping farther away from their yield strength, and the infrequent use of high-yield strength steels in construction reduces the risk of HAFC. The major concerns in the gas distribution network for re-use with H_2 are not primarily associated with metallurgy, but rather with leakage and permeation and associated climate warming and fire/explosion risk (see Figure 4).[26,28,29,52]

Hydrogen permeates through intact HDPE and other “soft goods” (polymeric and elastomeric materials used in gaskets, seals, and so on) at an appreciable rate.[53] The H_2 molecule's considerably smaller molecular diameter and high diffusivity relative to CH_4 lead to faster permeation, that is, more molecules of H_2 will permeate per unit time than molecules of CH_4 at a given pressure. There is also an overall tendency for H_2 to leak to a greater extent than that of natural gas.[53] Theory suggests that H_2 will leak at 1.3–3 times the rate of CH_4.[54]

	COMPONENT	ISSUES	IMPACTS & RISKS	SOLUTIONS & CHALLENGES
LOCAL DISTRIBUTION	**Pipeline material**	H_2 can permeate faster than natural gas (depending on flow regime) through plastic and other "soft" materials that pipelines, gaskets, seals are often made of	This can lead to both small and bulk leaks due to reduction in tensile strength, and sometimes even material changes in pipes which can reduce its lifetime	1. Limit amount of H_2 and de-blend if needed at point of use but limited decarbonization potential and energy intensive 2. Liners to reduce permeability but more research required
	Gas meters	Some can underreport flowrate when H_2 present and if flowrate increased there are technical challenges	Potential inaccurate measurements, incompatible design, hydrogen leakage	1. Limit amount of H_2 but limited decarbonization potential 2. Adjustments of gas metering and quality control systems but more research is needed 3. Replacement but costly

SAFETY Flammability hazards; worsened air quality
ENERGY SUPPLY Reduced reliability; service interruption
CLIMATE Climate-warming gas emissions
COST Lost product; and/or added expense
UNUSABLE New equipment needed; stranded assets

FIGURE 4 Existing natural gas distribution system suitability for pure hydrogen.

Measurements confirm the increased H_2 leakage rate through plastic piping of four to five times that of natural gas.[24,55] However, there are some limited lab experiments that indicate that hydrogen may leak at the same rate[56] or faster than methane[57] depending on flow regimes.

There is also some evidence of material property changes in HDPE piping after exposure to hydrogen, and additional research is warranted to understand a safe lifetime for HDPE pipes used in the distribution of hydrogen. There doesn't appear to be any safety concern related to premature failure arising from hydrogen exposure.[55] However, elastomeric materials exposed to hydrogen show reduction in tensile strength due to permeation, increasing the risk of larger leaks.[24]

The use of liners to reduce permeability may provide a partial solution, but more research is required.[42] Alternatively, blending hydrogen into the gas network for transport is another option to mitigate issues of transporting hydrogen, although it provides limited decarbonization potential. Some have raised the potential of de-blending when pure H_2 is required. Methods including pressure- or temperature-swing adsorption and selective membranes have been examined in detail.[24,55] The result would be a significant additional cost and energy demand per kilogram of pure hydrogen recovered.[24] Methane and hydrogen emissions associated with the separation process would also be of concern.

Gas meters in the distribution network would likely need significant retrofit or replacement.[26,58] Not only might they be required to measure gas volumetric flows three times as high as those required for fossil gas (to deliver same energy content to consumers), but diaphragm-type meters using large elastomeric or polymeric components have been known to under-report flowrate when fed gas mixtures containing hydrogen.[59]

3.4 | Storage

Natural gas systems contain both large storage elements for management of seasonal variation in gas use and smaller storage elements that manage daily variations in flow. The storage afforded by virtue of the volume of gas held up in the transmission and gas distribution network itself is referred to as "line pack." Line pack storage, in the form of the difference in pressure between nominal and minimum operating pressure for the gas system in question, can represent many hours of system demand. Such storage, absent from electrical distribution systems, is a critical tool for maintaining gas grid operational stability against fluctuations in demand and supply and against interruptions in service due to equipment failures or maintenance.[60]

Switching the gas system to pure H_2, with an energy density per unit volume roughly one-third that of a typical pipeline gas; therefore, would result in a reduction in "line pack" storage to one-third of the present value if storage pressure and volume are kept constant (Figure 5).[49] If pipeline design pressures must be de-rated to accommodate the added risks associated with hydrogen to the pipeline materials of construction (as discussed in Section 3.2), a further reduction in the line pack would be expected. This would either represent a reduction in reliability and peak flow handling capacity,

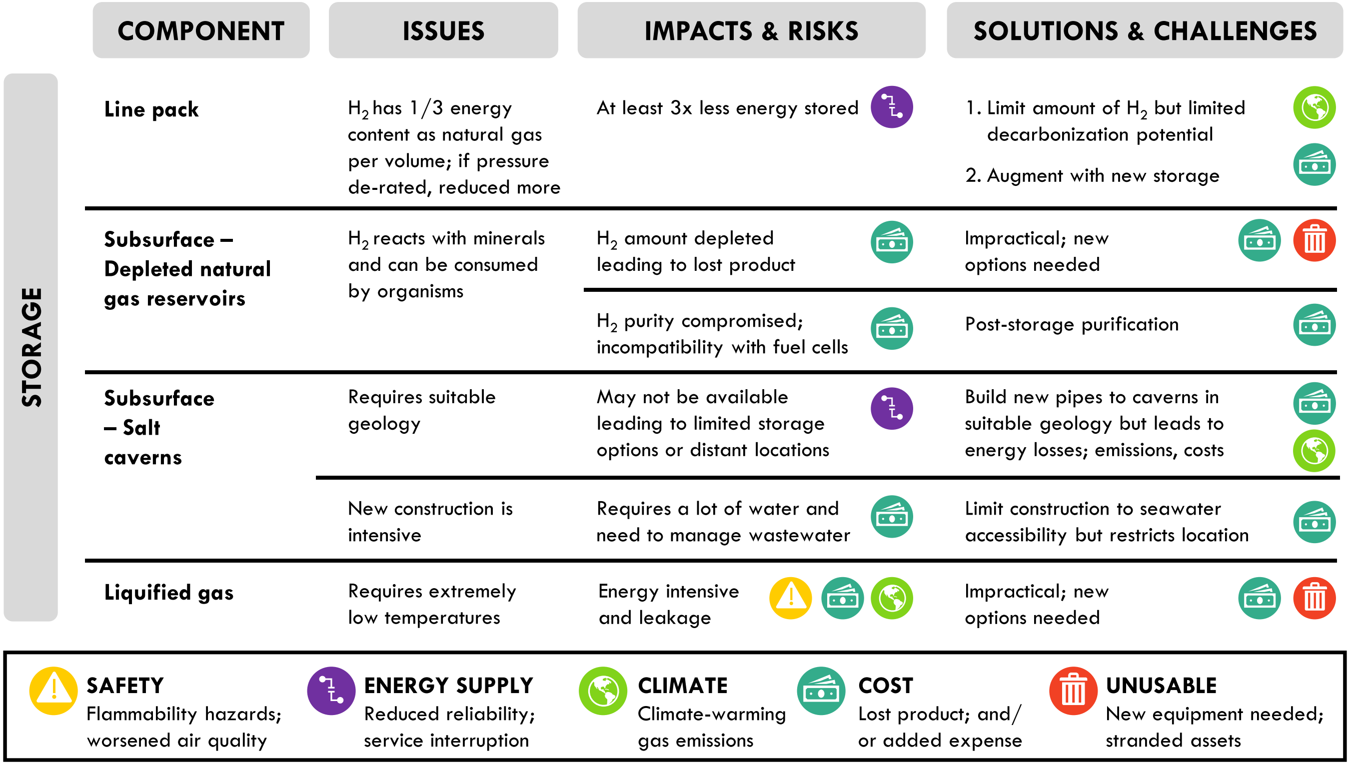

FIGURE 5 Existing natural gas storage system suitability for pure hydrogen.

or a need to install new dedicated storage not currently required on the network.

In most heating climates where gas use is much higher in winter than summer, additional gas storage is often incorporated into the gas network to provide a seasonal buffer. The volumes of gas involved are large, such that the use of above-ground storage facilities (such as the gas-o-meters previously used in the age of town gas) has largely been rendered impractical. Subsurface gas storage in depleted gas reservoirs, constructed salt caverns, and aquifers will be required to balance the system if there is variation in demand, yet H_2 is both geologically and biologically reactive.[61] Storing H_2 in depleted reservoirs formerly containing natural gas is possible but will likely result in depleted product.[55,62,63] Furthermore, uses such as fuel cells that require high purity hydrogen may be impaired if hydrogen has been contaminated due to storage in a former gas reservoir.[64]

On the other hand, using salt caverns for hydrogen storage should not compromise the integrity of hydrogen as it should not react with salt, and salt caverns are used today for natural gas storage.[65,66] However, suitable geology may not be available where storage capacity is required and not all salt domes are pure salt. Given the difficulties associated with using depleted natural gas reservoirs to store hydrogen, construction of "salt dome" storage facilities could represent a significant additional cost.[14]

3.5 | End use

Equipment (appliances, devices, and so on) designed to burn or derive energy from a gas mixture is optimized around the properties of that gas mixture. The tolerance for variations in gas properties, notably energy density per unit volume, flame speed, adiabatic flame temperature, explosive range, and the Wobbe index (an indicator of the interchangeability of fuel gases in combustion equipment) varies with the type of device. Most natural gas end-user devices can tolerate hydrogen additions to natural gas mixtures of up to about 20% by volume (about 7% in terms of energy content) without requiring significant modification.[24,55,67–71]

However, very few appliances or end-user devices designed to use fossil gas mixtures are suitable for use with pure H_2 without significant modification or replacement.[72]

Natural gas devices and appliances are incompatible with pure H_2 because of the physical and chemical differences between CH_4 and H_2 (Table 1). Hydrogen's smaller size allows it to escape more easily and permeate through materials, risking explosive-level concentrations and climate-warming emissions.[15] Hydrogen's lower density also causes it to rise and accumulate at high points in enclosed spaces. Although the difference in buoyancy is somewhat offset by hydrogen's greater diffusivity, the greater diffusivity can lead to more rapid leakage.

H_2 is also more explosive, ignitable, burns hotter, and the flame is faster with lower visibility than CH_4; these characteristics yield higher safety risks. The significant differences in properties between typical natural gas mixtures and H_2, therefore, necessitate changes in the design of burners and burner management systems to achieve comparative levels of safety, which must then be certified (Figure 6).[17,67] For example, all H_2 burner appliances require flame failure detection apparatus such as that used in the burners for ovens and broilers that shuts off the flow of gas when ignition does not result in a rise in gas temperature within a few seconds of the gas valve opening.

A quantitative risk assessment (QRA) was carried out in advance of a planned trial of pure H_2 in a residential gas distribution system in the UK.[18] The report concluded that even if the homes were fitted with appliances designed and certified for use with H_2, the risk of damage and injury due to fires and explosions would increase in frequency and severity. The report recommended that in addition to a leak testing program, excess flow devices of dissimilar type be installed in every home operating with H_2 (something, i.e., not currently done for natural gas supplies). One such device would be a conventional excess flow valve, which closes when flow through the valve greatly exceeds the maximum expected flow (due to, for instance, damage to a downstream pipe). Another would be a "smart meter," with an automated valve interlocked to close when the gas meter reported gas flow greater than the expected maximum. However, these devices were only expected to reduce the severity of fires and explosions, but not the frequency—therefore, the QRA asserted that injuries and deaths would be approximately the same as those encountered with existing gas use, even though events would be more frequent fires and explosions. The report also recommended that each room containing a gas appliance be fitted with a 10×10 cm nonclosing vent within 1.5 m of the ceiling, connected to the outdoors, to serve to vent any H_2 accumulating during a leakage event. Such vents would create a significant loss of heat and decreased comfort due to drafts, and therefore increased heating fuel use for the residents.

An additional safety challenge is the use of stenching agents, which are added to gas in the low-pressure distribution system to aid in leakage detection. Conventional sulfur-containing stenching agents, such as mercaptan used in the natural gas systems, are powerful fuel cell catalyst poisons.[64] However, they can be used as long as fuel cells are not deployed or are fitted with adsorbents to remove the stenching agent at the point of use, but this risks fuel cell failure.[73] Some previous research that has tested promising odorants compatible with fuel cells, but none appear commercially available.[74,75]

Finally, although H_2 combustion would eliminate the toxic risk of carbon monoxide—a consequence of natural gas combustion—it would not eliminate NO_x emissions that all fuels generate when burned in air, by virtue of the reaction of atmospheric nitrogen with oxygen. The hotter hydrogen flame could yield more NO_x emissions than natural gas.[71,72,76,77] Hydrogen combustion produces NO, which rapidly oxidizes to form NO_2, a pollutant regulated globally. NO_2 is a major health risk and is linked to childhood asthma among other ailments.[78] Residential and small commercial/industrial combustion equipment either vent into the room air (cooktops/hobs/ovens) or via a flue to the outdoors (boilers, furnaces), but without catalytic NO_x reduction equipment.[79–81] For devices with an enclosed flue (furnaces, boilers, and so on), catalytic NO_x reduction is possible but is expensive and high-maintenance, because a reducing agent is required which must be replenished.

4 | DISCUSSION AND CONCLUSION

Replacing natural gas with zero- and low-carbon hydrogen is viewed by many as an attractive decarbonization tool, because it can potentially re-use expensive infrastructure of considerable economic value. However, this paper has shown that there are numerous unresolved challenges with using hydrogen in the existing natural gas infrastructure due to its differing physical and chemical qualities compared to methane, the main component of natural gas. These differences have major implications for the entire natural gas value chain—encompassing production, long-distance transport, local distribution, storage, to end use. The existing infrastructure is mostly unusable without de-rating to lower pressures (with consequently much decreased energy flow rates) or substantial investments, which often rely on unproven solutions. In addition, end-use appliances need replacement, and even then, they would still have safety and health challenges that would need to be overcome with new solutions.

Although many of the concerns associated with deploying pure hydrogen energy systems can be mitigated by blending hydrogen with natural gas, doing so will not help decarbonize the economy as it does not facilitate a gradual transition to pure hydrogen, and it only offers a small reduction in GHG emissions. The benefits from reduced GHG emissions are limited due to the greatly lower volumetric energy density of hydrogen relative to the gas it displaces. For example, a mixture of 20% hydrogen (by volume) into natural gas is only about 7% hydrogen in terms of energy content and, in the best case,

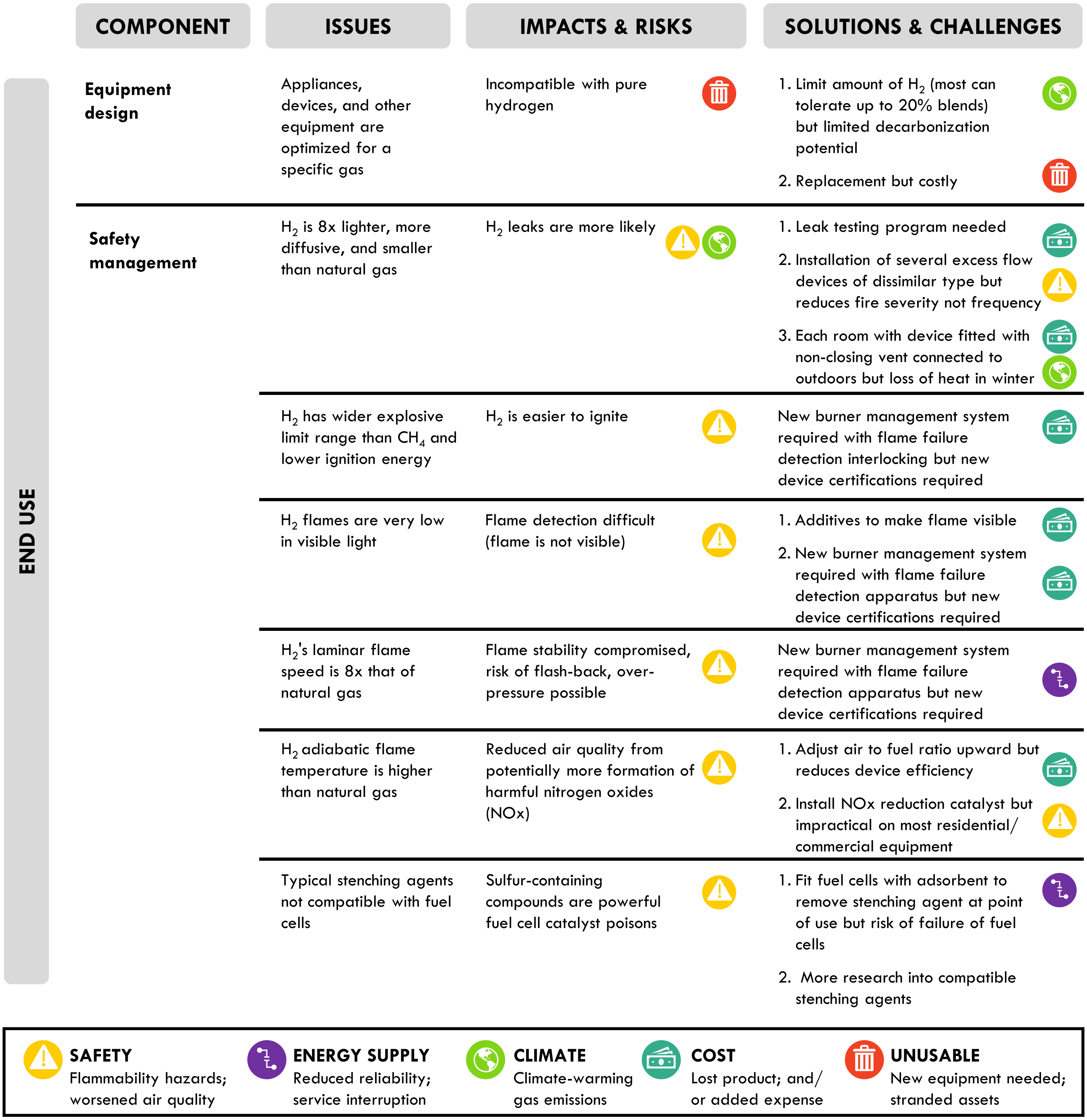

FIGURE 6 Existing natural gas end use system suitability for pure hydrogen.

represents only a 7% reduction in carbon dioxide emissions per joule of heat generated by its combustion. Furthermore, blending hydrogen with natural gas still has safety and climate risks from leakage and NO_x emissions.

Overall, while repurposing the natural gas system for use with hydrogen may, at first, seem appealing, the limited practicality, risks, and data gaps strongly suggest that like-for-like gas substitution provides limited benefits for increased risks, even if major technical and economic hurdles are overcome.

That said, continuing to rely on natural gas is also not a viable option for addressing the climate crisis. Considering its physical and chemical properties, hydrogen is not an effective decarbonization tool for use in homes and buildings. For any decarbonization strategy, it is critical to determine if a fuel is in fact needed, and to compare with potentially more effective options such as direct electrification using renewably generated electricity.

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SUPPORTING INFORMATION

Additional supporting information can be found online in the Supporting Information section at the end of this article.

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