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October 13, 2023

B.C. Sustainable Energy Association
c/o William J. Andrews, Barrister & Solicitor
70 Talbot Street
Guelph, ON
N1G 2E9

Attention: William J. Andrews

Dear William J. Andrews:

Re: FortisBC Energy Inc. (FEI)

2022 Long Term Gas Resource Plan (LTGRP) ~ Project No. 1599324

Response to the B.C. Sustainable Energy Association (BCSEA) Information Request (IR) No. 3 on Rebuttal Evidence

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On May 9, 2022, FEI filed the LTGRP referenced above. In accordance with the amended regulatory timetable established in British Columbia Utilities Commission Order G-150-23 for the review of the LTGRP, FEI respectfully submits the attached response to BCSEA IR No. 3 on Rebuttal Evidence.

For convenience and efficiency, if FEI has provided an internet address for referenced reports instead of attaching the documents to its IR responses, FEI intends for the referenced documents to form part of its IR responses and the evidentiary record in this proceeding.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Commission Secretary
Registered Interveners

58.0 Topic: Hydrogen Blending

Reference: Exhibit B-38, FEI Rebuttal Evidence in response to Intervener Evidence filed by My Sea to Sky, A5, p.2; Kevin Topolski et al., "Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology" (Golden, CO: National Renewable Energy Laboratory, 2022) online at: https://www.nrel.gov/docs/fy23osti/81704.pdf"

In A5 of its Rebuttal Evidence, FEI states that the challenges to hydrogen blending "are well understood and can be addressed."

In Footnote 1 on page 2 of its Rebuttal Evidence, FEI cites the Kevin Topolski et al. article cited above. The Topolski et al. article states:

> "… Finally, we discuss notable hydrogen blending demonstrations and their key outcomes. … Despite these successes, additional research across the entire hydrogen and natural gas supply chain will be needed to fill current knowledge gaps and better inform decision makers on future blending projects. This report summarizes findings from literature into key areas of consensus and disagreement. Research gaps and disagreements between the literature are highlighted to provide directions for future hydrogen blending research." [underline added]

58.1 Does FEI agree with the Topolski, et al. article's conclusion that "Despite these successes [with hydrogen blending demonstrations], additional research across the entire hydrogen and natural gas supply chain will be needed to fill current knowledge gaps and better inform decision makers on future blending projects"?

Response:

For clarity, FEI references the article by Topolski et al. for the proposition that "Hawaii Gas has been blending an average of 12 percent hydrogen into its gas network for over 50 years". FEI agrees with the authors' *overall* conclusion, which is that low-hydrogen-percentage blending is feasible in high-pressure transmission lines and low-pressure distribution lines as proven by international hydrogen blending demonstration projects, and that further research will be required to achieve the higher blends of hydrogen, in some cases up to 100 percent, that is planned for projects under commission.

58.2 Please further describe the technical assessments being conducted to ensure the safety and compatibility of hydrogen blends in FEI's infrastructure. What hydrogen concentrations are being assessed? What is the expected timeframe for the results?

Response:

Please refer to the responses to BCUC IR1 61.8 and 61.9. Both the hydrogen concentrations that will be assessed and the timelines remain under consideration as part of the activities outlined in these responses.

58.3 Please file a copy of the Topolski et al. article cited by FEI.

Response:

Please refer to Attachment 58.3 for the full report.

59.0 Topic: GHG Reductions from LNG as Marine Fuel

Reference: Exhibit B-38, FEI Rebuttal Evidence MS2S, A19, pp.16-19

FEI states:

> "As expanded on further below, FEI's estimate of potential GHG reductions from the use of LNG as a marine fuel is reasonable because:
>
> a) FEI has used BC-specific emission factors;
>
> b) FEI considers recent and reliable data and industry knowledge in assessing the impact of methane slip;
>
> c) FEI follows accepted standards for measuring global warming potential; and
>
> d) FEI relies on independent, peer-reviewed lifecycle well-to-wake emissions assessments." [p.16]

59.1 Please provide references in the evidentiary record for FEI's estimate of potential GHG reductions from the use of LNG as a marine fuel and for the four points listed above.

Response:

For clarity, FEI's Rebuttal Evidence to MS2S forms part of the evidentiary record and the requested information and references are found therein.[1] However, for convenience, FEI has summarized the evidence below.

FEI estimates that the use of Tilbury LNG could reduce GHG emissions from the use of LNG as a marine fuel by up to 27 percent. This estimate is supported by a recent independent consultant report by Affinity (Affinity Report),[2] which is aligned with the GHG emissions reductions estimated by Sphera in 2020 (Sphera Port of Vancouver Report).[3]

With respect to the four points listed in the preamble, and as provided in FEI's Rebuttal Evidence:

a) FEI's use of BC-specific emissions factors is discussed in the response to MS2S IR1 4.6, and supported by independent consultant reports from Affinity[4] and Sphera;[5]

---

[1] Exhibit B-38, FEI Rebuttal Evidence to MS2S. See in particular: pp. 16-19, A19.

[2] Affinity, "Study on the Air Quality Benefits to the Part of Vancouver by Adopting LNG as a Marine Fuel", (October 2022), p. 5, online at: http://tilburypacific.ca/wp-content/uploads/2022/10/Affinity-Study-Vancouver-Air-Quality-Report-02.09.2022.pdf.

[3] Sphera, "Life Cycle GHG Emissions of the LNG Supply at the Port of Vancouver – Final Results" (March 2020) online at: https://www.cdn.fortisbc.com/libraries/docs/librariesprovider5/sustainability-in-all-we-do/lifecycle-ghg-emissions-of-the-lng-supply-at-the-port-of-vancouver-footnote-8.pdf.

[4] Affinity Report, p. 5.

[5] Sphera Port of Vancouver Report, p. 1.

b) FEI refers to a number of recent reports and articles from reputable third parties, such as S&P Global,[6] MAN Energy Solutions,[7] the Port of Vancouver,[8] the University of British Columbia,[9] and SEA-LNG,[10] that it relied on to assess the impact of methane slip;

c) As described in FEI's Rebuttal Evidence, FEI follows the convention of leading international authorities in measuring greenhouse gas emissions using 100-year GWP, and is not aware of any country that uses the 20-year GWP as their sole representative measure for GHG reporting and accounting;[11]

d) For its global emission factors, FEI relies on the "Life Cycle GHG Emission Study on the Use of LNG as Marine Fuel" Report by independent consulting firm Thinkstep (now Sphera),[12] which was conducted according to ISO standards (the leading international standards on lifecycle GHG assessment) and was peer-reviewed by a panel of independent academic experts.

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6 S&P Global, "LNG still a viable solution for maritime decarbonization despite hurdles" (September 23, 2022) online at: https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/energy-transition/092322-lng-still-a-viable-solution-for-maritime-decarbonization-despite-hurdles#:~:text=Addressing%20methane%20slip&text=Later%20during%20the%20same%20month,improvements%20made%20in%20engine%20technologies.

7 Exhibit C16-6, MS2S Evidence, Footnote 9.

8 Exhibit B-21, Confidential Port of Vancouver Study.

9 Rochussen et al, "Development and demonstration of strategies for GHG and methane slip reduction from dual-fuel natural gas coastal vessels", *Fuel*, Issue 349 (2023) online at: https://www.sciencedirect.com/science/article/pii/S0016236123010463.

10 SEA-LNG, "ICCT Report on LNG Pathway Makes Flawed Assumptions Based on Outdated Data" (September 20, 2022) online: https://sea-lng.org/2022/09/icct-report-on-lng-pathway-makes-flawed-assumptions-based-on-outdated-data/.

11 Exhibit B-38, FEI Rebuttal Evidence to MS2S, pp. 18-19; see for discussion: United States Environmental Protection Agency, "Understanding Global Warming Potentials" (2023) online at: https://www.epa.gov/ghgemissions/understanding-global-warming-potentials; Climate Analytics, "Why using 20-year Global Warming Potentials (GWPs) for emission targets is a very bad idea for climate policy" (2017) online at: https://climateanalytics.org/briefings/why-using-20-year-global-warming-potentials-gwps-for-emission-targets-is-a-very-bad-idea-for-climate-policy/.

12 Thinkstep (now Sphera), "Life Cycle GHG Emission Study on the Use of LNG as Marine Fuel: Final Report" (2019) Commissioned by SEA-LNG limited and Society for Gas as a Marine Fuel Limited (SGMF), (Sphera GHG Report) online at: https://sea-lng.org/wp-content/uploads/2020/06/19-04-10_ts-SEA-LNG-and-SGMF-GHG-Analysis-of-LNG_Full_Report_v1.0.pdf. Sphera has since released an updated report: Sphera, "2nd Life Cycle GHG Emission Study on the Use of LNG as Marine Fuel: Final Report" (2021) Commissioned by SEA-LNG Limited and SGMF, online at: https://sphera.com/wp-content/uploads/2021/04/Sphera-SEA-LNG-and-SGMF-2nd-GHG-Analysis-of-LNG_Full_Report_v1.0.pdf.

Attachment 58.3

Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology

Kevin Topolski,[1] Evan P. Reznicek,[1] Burcin Cakir Erdener,[2] Chris W. San Marchi,[3] Joseph A. Ronevich,[3] Lisa Fring,[4] Kevin Simmons,[4] Omar Jose Guerra Fernandez,[1] Bri-Mathias Hodge,[1,2] and Mark Chung[1]

1 National Renewable Energy Laboratory
2 University of Colorado Boulder
3 Sandia National Laboratories
4 Pacific Northwest National Laboratory

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Office of Energy Efficiency & Renewable Energy
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Technical Report
NREL/TP-5400-81704
October 2022

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Technical Report
NREL/TP-5400-81704
October 2022

National Renewable Energy Laboratory
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List of Acronyms

CRADA	cooperative research and development agreement
EHS	electrochemical hydrogen separation
NO_x	nitrogen oxides
PE	polyethylene
PEM	proton exchange membrane
PSA	pressure swing adsorption
SMR	steam methane reforming
TEA	techno-economic analysis

Executive Summary

Hydrogen is an energy carrier that could play an important role in reducing emissions associated with difficult-to-decarbonize sectors, including peaking and load-following electricity and industrial heating. Blending hydrogen into natural gas pipelines has been proposed as an approach for achieving near-term emissions reductions and early-market access for hydrogen technologies such as electrolyzers. Numerous challenges and uncertainties complicate this approach to natural gas decarbonization, however, and this review summarizes current research on the material, economic, and operational factors that must be considered for hydrogen blending.

First, this review explores previous research regarding the effects of blending hydrogen on gas mixture fluid and thermodynamic properties, pipeline materials and equipment performance within transmission and distribution networks, and supporting facilities such as underground storage and end-use hydrogen separation. It is well known that the presence of hydrogen increases fatigue crack growth rates in commonly used pipeline steels, and studies have shown that metals with higher tensile strength tend to experience greater reductions in fracture resistance than metals with lower tensile strength when in contact with hydrogen. Recent research has shown that fatigue crack growth and fracture resistance can degrade even with low partial pressures of hydrogen, with subsequent degradation being more modest as the partial pressure is increased. In high-stress situations, fatigue crack growth is fairly independent of hydrogen concentration. Design guidelines such as ASME B31.12 provide instruction on how to assess a suitable operating pressure for many common pipeline materials given pipe diameter and thickness. Additional fatigue and fracture testing of vintage steels used in the U.S. natural gas pipeline system is needed to identify limiting behavior in hydrogen environments, especially for vintage seam welds and hard spots, and any existing pipelines under consideration for blending must be inspected for defects. While plastic piping is often considered suitable for hydrogen accommodation at distribution network pressures, research has shown that hydrogen can impact the physical properties, such as density and degree of crystallinity, of polyethylene materials. More research is necessary to quantify the effect of these changes on mechanical performance and lifetime of polymer pipes and pipe joints, along with the effects of hydrogen on specific resin formulations. The impact of hydrogen on materials also extends to compressors, valves, storage facilities, and other non-pipe components. Assessing hydrogen with underground storage facilities must also consider potential reactions associated with microorganisms that could consume hydrogen and the extent to which residual hydrocarbons present in depleted oil and gas reservoirs (the most common type of natural gas storage formation) is problematic for end-use applications based on the desired hydrogen purity. Hydrogen separation is a mature technology but likely cost-prohibitive for low hydrogen concentration blends in natural gas.

We also investigate and summarize studies that developed mathematical models of natural gas pipeline networks with hydrogen blending, as well as the operational and techno-economic findings of these network studies. Pipeline operational studies have shown consistent hydraulic and thermodynamic impacts of hydrogen blending in natural gas systems. Due to the low molecular weight of hydrogen, centrifugal compressors will need to increase rotational speed with increasing hydrogen concentrations to maintain a consistent pressure rise and will likely meet impeller stress limitations before reaching 100% hydrogen. The lower volumetric energy density of hydrogen results in a reduction in energy transmission capacity at fixed pipeline pressures, and maintaining either consistent pipeline pressures or energy transmission capacity requires a significant increase in compression energy due to the lower molecular weight of hydrogen. Proper economic assessment of hydrogen blending opportunities must balance operational considerations such as pressure de-rating of existing pipelines, increased compression energy, and increased inspection frequency with capital upgrades such as new pipelines, compression stations, and end-use application retrofits and with opportunity costs associated with reduced energy transmission capacity. Furthermore, the interlinked nature of the electricity grid and gas network via hydrogen production from electrolysis and gas-fired power plants necessitates a broader analysis of both systems to determine if blending, and eventually replacing natural gas with hydrogen, is a viable pathway to economywide decarbonization.

Finally, we discuss notable hydrogen blending demonstrations and their key outcomes. Many blending demonstrations internationally have proven that low-hydrogen-percentage blending is feasible under very specific scenarios with limited end-usage applications on both high-pressure transmission lines and low-pressure distribution lines. Many projects under commission today and in the near future are targeting higher blends of hydrogen, some up to 100%. The United States has successfully commissioned a handful of blending projects, but to date, the most successful and longest-running one is Hawaii Gas's introduction of a 12% to 15% blend in its network. Despite these successes, additional research across the entire hydrogen and natural gas supply chain will be needed to fill current knowledge gaps and better inform decision makers on future blending projects. This report summarizes findings from literature into key areas of consensus and disagreement. Research gaps and disagreements between the literature are highlighted to provide directions for future hydrogen blending research.

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1 Introduction

Hydrogen could play a valuable role as an energy carrier in future decarbonized energy systems. Hydrogen can be produced from a variety of low-carbon sources including coal or natural gas with carbon capture and sequestration (CCS), biomass, and nuclear and renewable electricity and can be used for applications including seasonal energy storage; light-, medium-, and heavy-duty transportation; and residential, commercial, and industrial heating and power (Ruth et al. 2020). Developing the infrastructure necessary to accommodate hydrogen for these various applications, however, remains a key challenge. Researchers, companies, and both local and national governments around the world are considering blending hydrogen into natural gas pipeline networks in order to benefit from hydrogen without the economic burden of building new dedicated infrastructure. This approach carries many potential benefits but also poses numerous challenges.

Blending low-carbon hydrogen into natural gas could potentially reduce the carbon intensity of difficult-to-decarbonize sectors that are currently served by natural gas, including electricity peak power production, residential and commercial heating, and industrial processes. Blending hydrogen produced from low-carbon sources such as wind and solar electricity into natural gas infrastructure could reduce the carbon footprint of natural gas and of all applications that rely on it (Melaina, Antonia, and Penev 2013). Mukherjee et al. (2015) assessed the economics and emissions of using surplus power in Ontario to produce electrolytic hydrogen for blending and distribution within natural gas infrastructure. They considered two cases: one that employed buffer storage for hydrogen and one that did not employ storage. Their results indicate that delivering hydrogen-enriched natural gas to end-users could reduce CO_2 emissions by 9,429 metric tonnes with hydrogen storage and 3,504 metric tonnes without hydrogen storage. Similarly, Qadrdan, Abeysekera, et al. (2015) evaluated the impact of using electrolyzers to produce hydrogen for injection into the U.K. gas grid in a study that simultaneously minimized the operating costs for the U.K. gas and electricity grids. This study found that in a low future electricity demand scenario, unregulated hydrogen injection could achieve 3% penetration by energy in the gas grid, a 7% reduction in system operating costs, and approximately 2% reduction in total system emissions. Note that this modest reduction in emissions was calculated solely by minimizing total system operating costs; aggressive renewable portfolio standards or decarbonization targets could drive hydrogen production to achieve more substantial emissions reductions.

Hydrogen can also improve energy resiliency and security by acting as a parallel energy vector to grid electricity, which is a service that the natural gas grid already provides. Like natural gas, hydrogen offers a way to provide peak electricity when the grid needs it and can provide an alternative to electricity for applications such as residential and commercial heating. Hydrogen can also serve as a flexible electrical load, which is a capability that will become increasingly beneficial as more variable renewable energy resources begin supplying power to the electricity grid. Specifically, water electrolysis offers a potential route for utilizing low-cost excess renewable electricity to produce hydrogen. This technology utilizes electricity to split water into hydrogen and oxygen via an electrochemical reaction (Grigoriev and Fateev 2017). Several types of electrolyzer technologies exist. Alkaline electrolyzers are the most technologically mature (Saba et al. 2018) and have been deployed globally for decades. Their advantages include availability, durability, and the avoidance of noble metals as construction materials; however, they operate at lower current densities and pressures and experience limitations in dynamic operation (Schmidt et al. 2017). Proton exchange membrane (PEM) electrolyzers are less mature than alkaline electrolyzers and require expensive platinum catalysts but maintain key advantages including high power density, ability to operate at higher pressures, and greater operational flexibility (Schmidt et al. 2017). Solid oxide electrolyzers are less commercially mature than alkaline and PEM electrolyzers. These electrolyzers utilize a solid ceramic ion-conducting electrolyte and operate at very high temperatures. Although they can achieve high efficiency and rely on low-cost materials, the high-temperature operation complicates balance-of-plant design and reduces operational flexibility (Schmidt et al. 2017). Anion exchange membrane electrolyzers are a novel type of electrolyzer that can combine the best aspects of alkaline electrolyzers and PEM electrolyzers by utilizing low-cost metal catalysts and simple electrolytes; however, anion exchange membrane electrolyzers are still in the R&D phase of development (Zakaria and Kamarudin 2021; Li and Baek 2021). Of these electrolyzer types, PEM electrolyzers are considered one of the most promising for implementation with renewable electricity because they are commercially mature, offer modular implementation options and operational flexibility, and have significant potential for future cost reductions (Hunter et al. 2021). While daily energy arbitrage can likely be accomplished most cost-effectively with batteries (Schmidt et al. 2019), a recent study found that hydrogen storage in geologic caverns utilizing PEM electrolyzers and either PEM fuel cells or hydrogen combustion turbines could achieve lower levelized cost of storage for long durations (120 hours of continuous discharge at rated power) than conventional storage technologies such as lithium-ion batteries, compressed air energy storage, and pumped hydro storage (Hunter et al. 2021). This type of hydrogen storage, however, requires suitable geologic formations and transmission of either hydrogen or electricity to and from the storage site. The United States already has over 4 trillion cubic feet of belowground natural gas storage, which equates to thousands of hours of storage duration (Albertus, Manser, and Litzelman 2020), and utilizing existing natural gas infrastructure to transport hydrogen could eliminate the need to build new hydrogen pipelines and/or electricity transmission lines to accommodate renewable-powered electrolysis. For these reasons, the natural gas grid could provide a convenient and effective way to begin storing renewable electricity by simply installing electrolyzers. In this manner, hydrogen blending into natural gas infrastructure could also provide an early market opportunity for electrolysis.

Electricity from nuclear plants can also be used to produce hydrogen (Frank et al. 2021), which may be advantageous in scenarios where low electricity demand or high variable renewable energy penetration force baseload plants (including nuclear plants) to sell electricity at near-zero or negative prices in order to avoid shutdown and startup costs (Kim, Boardman, and Bragg-Sitton 2018). Fossil fuels such as natural gas and coal can be and are used to produce hydrogen via steam methane reforming (SMR) and coal gasification, respectively (Siddiqui and Dincer 2019; Sánchez-Bastardo, Schlögl, and Ruland 2021). Producing hydrogen from fossil fuels for blending into natural gas pipelines is likely only appropriate when carbon capture and sequestration opportunities are low-cost and readily available near the site of hydrogen production; in fact, producing hydrogen for blending via SMR without carbon capture and sequestration can actually increase emissions (Di Lullo, Oni, and Kumar 2021). Methane pyrolysis is currently being pursued as a hydrogen production method that can simplify the carbon capture and sequestration process by producing hydrogen and solid carbon via thermal decomposition; however, this process is not as mature as SMR or water electrolysis, requiring additional research to identify the impact of natural gas impurities on catalytic performance, how to best industrialize the process, and what to do with the carbon byproduct (Sánchez-Bastardo, Schlögl, and Ruland 2021).

Many companies, researchers, and governments are interested in blending hydrogen into natural gas grids because doing so could contribute toward economywide decarbonization while maintaining some of the benefits that natural gas networks offer to regional, national, and global energy systems. Natural gas networks provide an energy vector parallel to the electricity grid that offers added energy transmission capacity and inherent storage capabilities, in addition to the aforementioned geologic storage reserves. These natural gas network characteristics improve energy system resilience and security (GRTgaz et al. 2019), and the United States already has a vast natural gas network. Continuing to make use of existing gas networks for hydrogen might offer a lower-cost, more resilient pathway to economywide decarbonization than electrification alone, and converting natural gas networks to operate with hydrogen could increase the number of markets that they serve. Figure 1 shows the U.S. Department of Energy's H2@Scale concept, illustrating potential routes to produce hydrogen and applications that it can serve. In addition to traditional markets served by natural gas including power production, heating, chemical and industrial processes, and metals and fertilizer production, hydrogen could also be used to make synthetic fuels or to directly fuel hydrogen vehicles (Ruth et al. 2020).

Although blending hydrogen into natural gas infrastructure may have numerous benefits, various factors and uncertainties regarding hydrogen's material and equipment performance impacts on existing natural gas pipeline infrastructure challenge its implementation. These factors and uncertainties broadly pertain to compatibility of various components of natural gas transmission and distribution networks. Figure 2 shows a schematic of a typical natural gas network. These networks currently consist of natural gas extraction, processing, transmission, and distribution to end-users, some or all of which could be affected by the introduction of hydrogen (depending on where it is injected). Hydrogen has significantly different thermodynamic, transport, and combustion properties than natural gas. Structural and safety concerns associated with hydrogen blending include pipeline system material degradation and gas leakage. Gaseous hydrogen has a significant impact on fatigue and fracture resistance of line pipe steels, and questions remain regarding how to account for this when assessing steel pipeline compatibility with hydrogen. The effects of hydrogen on polyethylene pipeline materials are not fully understood and require additional testing to confirm their tolerance of hydrogen. The design of installed pipeline and pipeline components such as compressor stations, pressure reduction stations, underground storage facilities, valves, and meters may not be appropriate to maintain equivalent energy transport capacity with hydrogen blending. This may prompt additional capital investments to pursue retrofit projects that increase pipeline capacity, maintain adherence to safety guidelines, and prolong pipeline design lifetime. Understanding the economic and technical risks associated with these projects will require

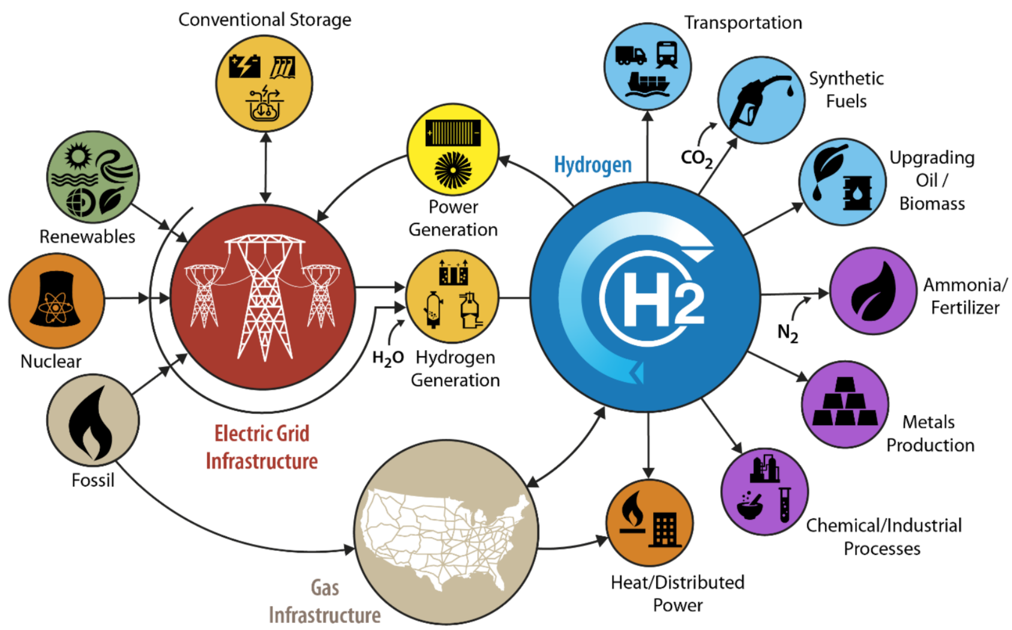

Figure 1. Hydrogen production and utilization pathways (Ruth et al. 2020)

detailed economic assessments and technical demonstrations. This review discusses these questions and the research progress toward improving the understanding of the economic and technical challenges associated with blending hydrogen into natural gas networks. The insights developed from these hydrogen blending assessments are also applicable to natural gas pipeline conversion to transport pure hydrogen.

Prior literature reviews have investigated hydrogen compatibility of various components of the natural gas pipeline system (Melaina, Antonia, and Penev 2013; Altfeld and Pinchbeck 2013; Hodges et al. 2015; Gondal 2019; GPA Engineering 2019; Domptail et al. 2020). Although some of their findings hold true today, many of these previous reviews make statements that are problematic or inaccurate. Altfeld and Pinchbeck (2013) highlight hydrogen compatibility for sensitive pipeline systems components. The authors provided U.S.-applicable hydrogen blending guidance for a natural gas pipeline network based on network end-users present and network prime movers. Melaina, Antonia, and Penev (2013) review several key issues concerning blending hydrogen into the U.S. natural gas pipeline system. They claim that in general, only minor issues arise when blending less than 5%–15% hydrogen by volume and that these low blend levels should not increase risks associated with end-use devices, public safety, or durability

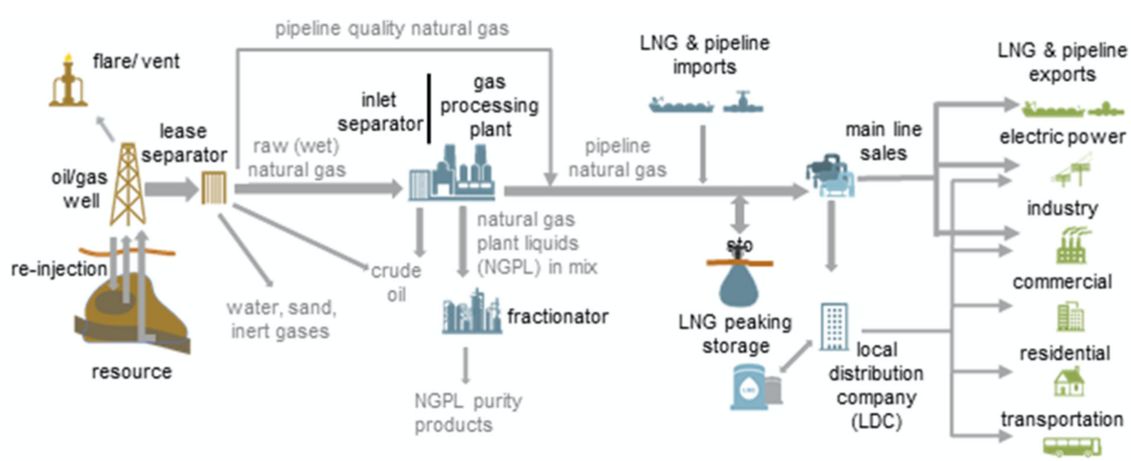

Figure 2. Schematic overview of a natural gas network (Dyl 2020)

and integrity of the gas pipeline network (note that although this may be true of distribution systems, it is not true of transmission systems operating near or at full capacity, as we subsequently discuss in the present review). Hodges et al. (2015) examine the hazards associated with introducing hydrogen into Great Britain's gas network and gas appliances. This report claims that hydrogen blending up to 20 vol % in Great Britain's low-pressure distribution gas network is unlikely to increase hazardous risk to end-users. Gondal (2019) reviews power-to-gas projects to assess natural gas pipeline component hydrogen compatibility. The author posits that pipeline network compatibility is dependent on the most limiting pipeline component. GPA Engineering (2019) conducted an investigation into the technical, safety, and regulatory impacts of blending hydrogen up to 10 vol % in Australian gas distribution networks. The authors note that although there are no regulatory barriers to prevent blending up to 10 vol % in Australian gas distribution networks, they questioned the applicability of the current Australian regulatory framework to hydrogen-blended natural gas because several foundational standards used in regulation have not been written with hydrogen use in mind. For example, the investigation noted higher potentials for hydrogen embrittlement for AS 2885, a standard that covers high-pressure pipelines (Standards Australia 2018a). The investigation also found minor gaps in materials and safety knowledge for AS/NZS 4645, a standard covering natural gas distribution pipeline networks (Standards Australia 2018b). Domptail et al. (2020) provide a path for further research such that natural gas pipeline operators can safely and reliably inject hydrogen at increasing blending levels into their pipeline networks, and recommend the natural gas pipeline industry prioritize research in metering accuracy and integrity, compressor stations, and inspections and maintenance, among many other areas.

Although several publications emphasize taking a case-dependent approach to evaluate natural gas pipeline network hydrogen fitness (Melaina, Antonia, and Penev 2013; Altfeld and Pinchbeck 2013; GPA Engineering 2019; Domptail et al. 2020), there is a tendency in the hydrogen blending literature to generalize hydrogen compatibility as blending limits across the natural gas pipeline segments and pipeline components. Blending limit generalization is problematic because hydrogen compatibility depends on existing infrastructure component factors including specific equipment model, equipment condition, and material of construction. Each natural gas pipeline network is also unique to the set of end-users supplied, network configuration, and maximum gas transport capacity. Therefore, an evaluation of hydrogen blending compatibility should be specific to a given natural gas pipeline network and detailed to account for hydrogen blending impacts on individual pipeline system components such as compressors, prime movers, meters, valves, storage facilities, and the pipeline itself. The impact to pipeline end-users should also be considered. Table 1 provides several high-level hydrogen blending impacts relevant to various natural gas end-users under critical limiting factors, as well as critical parameters to enhance hydrogen blending compatibility with regard to equipment performance in reliability and emissions and natural gas consumption (segregated by pipeline delivery mode and end-use sector). These are presented to highlight potential value capture and decarbonization opportunities in applying hydrogen blending within the distribution and/or transmission pipeline networks.

The HyBlend initiative was created by the U.S. Department of Energy's Hydrogen and Fuel Cell Technologies Office with the objective of addressing technical barriers to blending hydrogen in natural gas pipelines. The Pipeline Blending Cooperative Research and Development Agreement (CRADA)—a HyBlend project—was formed by the Hydrogen and Fuel Cell Technologies Office in partnership with industry stakeholders and four national labs to address pipeline material compatibility and degradation, techno-economic analysis (TEA), and life cycle assessment of blending impacts (Office of Energy Efficiency & Renewable Energy 2021). The key goals of the Pipeline Blending CRADA are to develop tools that de-risk hydrogen blending applications, assess the economics of multiple energy delivery pathways, and analyze the hydrogen blending life cycle impact. This CRADA will leverage U.S. national laboratory capabilities and related research efforts to achieve key HyBlend goals. Over 20 participants representing industry, academia, and state entities have joined this CRADA in partnership with the U.S. Department of Energy. The participants' roles, generally speaking, are to guide and/or inform research to yield applicable insights to better inform industrywide solutions to hydrogen blending. More specifically with respect to TEA and the National Renewable Energy Laboratory's deliverable, participants' roles are to help identify the most economically critical natural gas supply chain segments by providing insight or guidance into this literature review and the development of a natural gas pipeline upgrade tool and how it will integrate with a broader natural gas and electrical grid optimization framework. The pipeline upgrade tool is a key TEA deliverable of the Pipeline Blending CRADA for the National Renewable Energy Laboratory and will be open-source and available to the public at the end of this CRADA around October 2023. The present literature review serves as an initial step in techno-economic research activity for the Pipeline Blending CRADA and seeks to identify the current knowledge base regarding the compatibility of individual pipeline components to accommodate hydrogen and how hydrogen blending affects pipeline operations.

Table 1. Hydrogen End-Use Applications in Natural Gas Pipeline Systems (Altfeld and Pinchbeck 2013; Hodges et al. 2015; Gondal 2019; Domptail et al. 2020; Kopalek et al. 2021; South Coast Air Quality Management District 1978, 1998)

Natural Gas End Use Sectors	2019 Annual U.S consumption (Bcf)	Pipeline Transport Sections	Natural Gas End Use Applications	Hydrogen Blending Critical Limiting Factors	Critical Parameters to Extend Hydrogen Blending Compatibility
Pipeline Fuel	1,018	Transmission	Gas Turbines	• NO_x emissions • Flashback • Combustion dynamics	• Burner design • Flame detection • Derated Capacity
			Internal Combustion Engines	• NO_x & THC emissions • Misfiring • Engine knock • Peak Pressure & Temperature • Detonation Risk	• Fuel/Air Ratio • Ignition Timing
Industrial	8,417	Transmission & Distribution	Chemicals	• NO_x Emissions • Balance of Plant	• Furnace Temperature
			Petroleum and Coal Products		
			Primary metal		
			Paper	• Flue Moisture Content	• Burner design, configuration • Combustion adjustment
			Food		
Power Generation	11,288	Transmission	Gas Turbines	• NO_x Emissions • Flashback • Combustion dynamics	• Burner design • Flame detection • Derated Capacity
		Transmission / Distribution	Internal Combustion Engines	• NO_x & THC emissions • Misfiring • Engine knock • Peak Pressure & Temperature • Detonation Risk	• Fuel/Air Ratio • Ignition Timing
Residential	5,019	Distribution	Boilers	• NO_x & THC emissions	• Fuel/Air Ratio
			Burners	• Surface Temperature	• Burner Design
Commercial	3,515	Distribution	Internal Combustion Engines	• NO_x & THC emissions • Misfiring • Engine knock • Peak Pressure & Temperature • Detonation Risk	• Fuel/Air Ratio • Ignition Timing

Note. THC = Total hydrocarbon; NO_x = Nitrogen Oxides

We review methods and results of previous hydrogen blending techno-economic studies and summarize the current state of hydrogen blending demonstrations around the world. This information directly informs the development of models and analytic tools to evaluate the technical requirements of blending hydrogen as part of the HyBlend initiative's objectives. The Pipeline Blending CRADA will also explore how hydrogen blending may impact natural gas pipeline operations and revenue opportunities. The rest of this review is organized as follows: Sections 2 and 3 discuss the effects of hydrogen blending on gas properties and existing pipeline infrastructure, respectively. Section 4 provides an overview of existing modeling approaches and analytical tools for hydrogen blending impact evaluation. An overview summarizing TEA research is provided in Section 5. Findings from significant hydrogen blending demonstrations are discussed in Section 6. Section 7 discusses areas of consensus, disagreement, and uncertainty in the present literature and summarizes remaining research questions.

2 Hydrogen Blending Impacts on Natural Gas Properties

Reliable model representations of the pipeline system require accurate gas mixture property estimation over the range of relevant operating conditions. Tables 2 and 3 provide a range of operating conditions and gas qualities, respectively, reported in Melaina, Antonia, and Penev (2013) and the American Gas Association's *Gas Quality Management Manual* (Grimley 2019) for both transmission and distribution pipeline systems. These tables provide ranges of operating conditions (rather than specific values) because natural gas pipeline transport specifications vary by region and provider. Foss (2004) documents a survey of natural gas transmission pipeline specifications that show how gas quality specifications vary over multiple pipeline operators located across the United States and Canada. Regional variability on natural gas composition has implications on how certain end-use equipment is designed and tuned for an acceptable range of natural gas compositions (NGC+ Interchangeability Work Group 2005). Straying beyond the acceptable composition range of certain end-use equipment may increase emissions and reduce equipment reliability.

Table 2. Pipeline Operating Conditions (Melaina, Antonia, and Penev 2013; Grimley 2019)

Pipeline	Distribution		Transmission	
	Min	Max	Min	Max
Pressure (psig)	0.25	300	600	2,000
Temperature (°F)	20	140	20	140

Table 3. Typical Pipeline Gas Properties (Grimley 2019)

Gas Quality Specification	Units	Min	Max
Higher heating value[1]	Btu/scf	900–1,000	1,075–1,200
Wobbe Index	BTU/scf	1,279–1,340	1,380–1,400
Hydrocarbon dew point[2]	°F		0–25
Cricondentherm hydrocarbon dew point	°F		15–20
Butanes	%		0.75–1.5
Liquifiable pentane fraction	gal/Mscf		0.2–0.3
Pentanes	%		0.12–0.25
Water vapor content	lb_m/MMscf		4–7
Total sulfur compounds, as S	grains/100 scf		0.5–20
Hydrogen sulfide (H_2S)	grains/100 scf		0.25–1
Mercaptans	grains/100 scf		0.2–2
Solid particle size	microns		3–15
Hydrogen (H_2)	ppm		400–1,000
Total diluent gases	%		3–6
Carbon dioxide (CO_2)	%		1–3
Nitrogen (N_2)	%		1–4
Oxygen (O_2)	%		0.001–1

[1] Dry, at 14.73 psia and 60°F

[2] At either fixed or operating pressures.

2.1 Thermodynamic and Transport Properties

The composition in delivered natural gas could vary over different regions in the United States due to natural gas imports and rich natural gas resource discovery (Foss 2004; NGC+ Interchangeability Work Group 2005). Today's natural gas pipeline system is interconnected and manages regional natural gas composition variability through a combination of upstream gas processing, pipeline tariffs (which, in addition to accounting for transportation charges, also place limitations on quality and composition to limit impacts of impurities in the natural gas stream), and operational flow orders, which are a mechanism used by pipeline operators to limit the delivery of gas transported in a given area. Operational flow orders may entail limiting shippers and customers to a maximum or minimum flow of gas so as to protect pipeline network operational integrity. Minor shifts in natural gas composition could lead to challenges in pipeline operation due to shifts in gas mixture properties such as density, dynamic viscosity, Joule-Thomson coefficient, heat capacity, thermal conductivity, volumetric energy density, and vapor-liquid equilibrium (Schouten 2004; Kurz et al. 2019; Bainier and Kurz 2019; Abd et al. 2021). Hassanpouryouzband et al. (2020) and Li et al. (2021) provide focused discussions on how these thermophysical properties change with hydrogen composition. Capacity bottlenecks, metering inaccuracies, and degraded network control are potential consequences that can result from a shift in gas composition. These effects of thermodynamic property changes on both pipeline equipment and networks are covered in Sections 3 and 4 of this review. Research in natural gas networks for evaluating gas composition shifts relies on a number of equations of state to accurately estimate the effect on gas properties with respect to temperature and pressure. The equations of state commonly used for gas network modeling include Peng-Robinson (1976); Soave, Redlich, and Kwong (1972); AGA8 DC92 (Starling and Savidge 1992); and GERG-2008 (Kunz and Wagner 2012).

2.2 Combustion Properties

Differences in combustion properties between hydrogen and natural gas can also create complications for pipeline operations and end-user applications when blending hydrogen. Table 4 gives a high-level overview of combustion-related characteristics for hydrogen and methane (which is the major constituent of natural gas) that can impact engines, turbines, and burners if significant quantities of hydrogen are present. These differences in characteristics can also impact pipeline compression station operations because some natural gas pipeline compression stations are powered by natural gas prime movers that pull a small amount of fuel from the pipeline.

Table 4. Methane and Hydrogen Combustion Properties (Kurz et al. 2019; Korb, Kawauchi, and Wachtmeister 2016; Goldmeer and Catillaz 2021)

Gas Characteristic	Units	Methane	Hydrogen
Wobbe Index	Btu/scf	1,215	1,039
Lower heating value	Btu/scf	911.6	274.7
	Btu/lb	21,515	51,593
Minimum ignition energy	Btu	$2.7 \cdot 10^{-7}$	$1.9 \cdot 10^{-8}$
Lower flammability limit	vol %	4.4	4
Upper flammability limit	vol %	17	75
Methane number	-	100	0
Flame speed	cm/s	30–40	200–300
Adiabatic flame temperature	°F	3,565	4,000

Trends to mixture heating, reactivity, and emissions effects are observed as hydrogen content increases. As could be inferred from Table 4, the mixture heating values decrease as hydrogen content increases. Wobbe Index, which is an indicator that specifies fuel interchangeability, is an exception; its minimum value is reached at 85 vol % hydrogen and increases thereafter, as seen in Figure 3. Hydrogen admixtures also become more unstable with higher hydrogen contents, as hydrogen has a wider window of flammability and lower minimum ignition energy (Mathurkar 2009). Pure hydrogen gas flames are difficult to detect, as they are nearly invisible during daylight (Hord 1976; HySafe 2007). Flame visibility improves with the presence of impurities such as methane. Flame speeds and flame temperatures increase for gas mixtures of increasing hydrogen composition (Brower et al. 2013; Ren et al. 2019). The latter effect on temperature has implications in emissions as more nitrogen oxides (NO_x) could be formed. Gas explosivity limits are case-dependent and depend on additional conditions such as ignition location, ignition strength, and confinement (Hord 1976). These limits require a more detailed analysis than the high-level overview presented in Table 4.

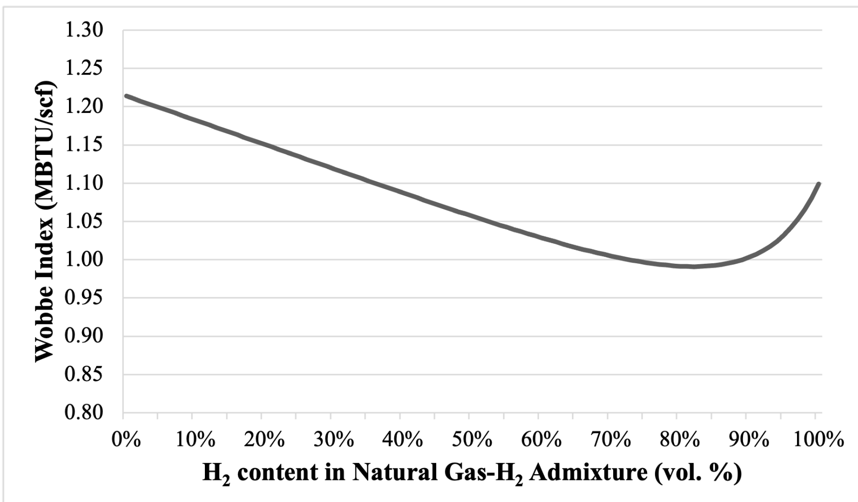

Figure 3. Effect of hydrogen composition on Wobbe Index.

3 Hydrogen Blending Impacts on Natural Gas Pipeline Systems

Determining the impact of injecting hydrogen into the natural gas pipeline system is non-trivial because significantly changing gas mixture thermodynamics and transport properties can create challenges for existing network infrastructure and end-use appliances. These challenges and the respective locations where they occur within the natural gas pipeline system are summarized in Table 5. Without addressing these challenges, hydrogen injection into gas pipelines could lead to negative pipeline economic, safety, and reliability consequences. Consideration of hydrogen blending opportunities must take into account necessary modifications to equipment and changes to network operating procedures to ensure safety, reliability, and economic viability. The following subsections address these considerations from a network section scale down to an individual equipment basis for both transmission and distribution networks.

Table 5. Challenges associated with hydrogen blending in transmission and distribution networks

Challenges With Hydrogen Blending	Natural Gas Pipeline System Section Impacted
Enhanced fatigue crack growth in pipeline steel	Transmission and distribution networks
Reduced fracture resistance in pipeline steel	Transmission and distribution networks
Reduced energy transmission capacity	Transmission and distribution networks
Increased pressure drop when meeting energy demand	Transmission and distribution networks
Increased gas velocities	Transmission and distribution networks
Increased required compression power	Transmission networks
Increased centrifugal compressor rotational speed	Transmission networks
Shifted centrifugal compressor operating envelope	Transmission networks
Increased NO_x emissions for prime movers and end users	Transmission and distribution networks
Excessive combustion dynamics, flame lift-off, flashback	Transmission and distribution networks
Fuel pre-ignition in internal combustion engines	Transmission networks
Meter accuracy and durability	Transmission and distribution networks
Valve leakage and durability	Transmission and distribution networks
Gas composition analysis accuracy	Transmission and distribution networks
Hydrogen leakage in polymer piping	Distribution networks
Biochemical hydrogen conversion in underground storage	Transmission networks
Hydrogen loss through cap rock in underground storage	Transmission networks

3.1 Transmission Pipeline Networks

Nearly all of the transmission pipeline systems in the United States consist of 4–48-in.-diameter steel piping, with wrought iron, plastic, and other materials making up 0.5% of remaining mileage (Melaina, Antonia, and Penev 2013). Distributed facilities along the pipeline include compressor, valve, and meter stations. The purpose of the transmission pipeline system is to transport large volumes of gas over long distances within and across state lines. Figure 4 illustrates the geographical extent of the transmission pipeline system across the continental United States. The transmission pipelines transport processed natural gas from upstream gas processing plants to a variety of end-users, including distribution networks, power plants, and large industrial manufacturing. City gates, which serve as the intersection of transmission pipelines and distribution networks, provide custody transfer services in pressure regulation, gas measurement, calorimetry, and odorant injection. City gates are needed to reduce upstream gas pressures to suitable pressures for distribution pipelines and end-users, measure and control the gas being transferred, and inject odorant so gas consumers can smell low concentrations of natural gas (American Gas Association 2022). The following sections summarize the effects of hydrogen blending on pipeline materials, transport, and non-pipeline component performance.

3.1.1 Hydrogen Materials Compatibility of Line Pipe Steels

Gaseous hydrogen has a considerable effect on fatigue and fracture resistance of steels, including line pipe steels and any other steel components operating at pressure within a pipeline. These effects are important because fatigue crack growth and fracture resistance are properties used directly in fitness-for-service assessments of pressure pipe, as described in API 579/ASME FFS-1 (American Society of Mechanical Engineers and American Petroleum Institute 2021) and ASME B31.12 (American Society of Mechanical Engineers 2019). If the appropriate properties are

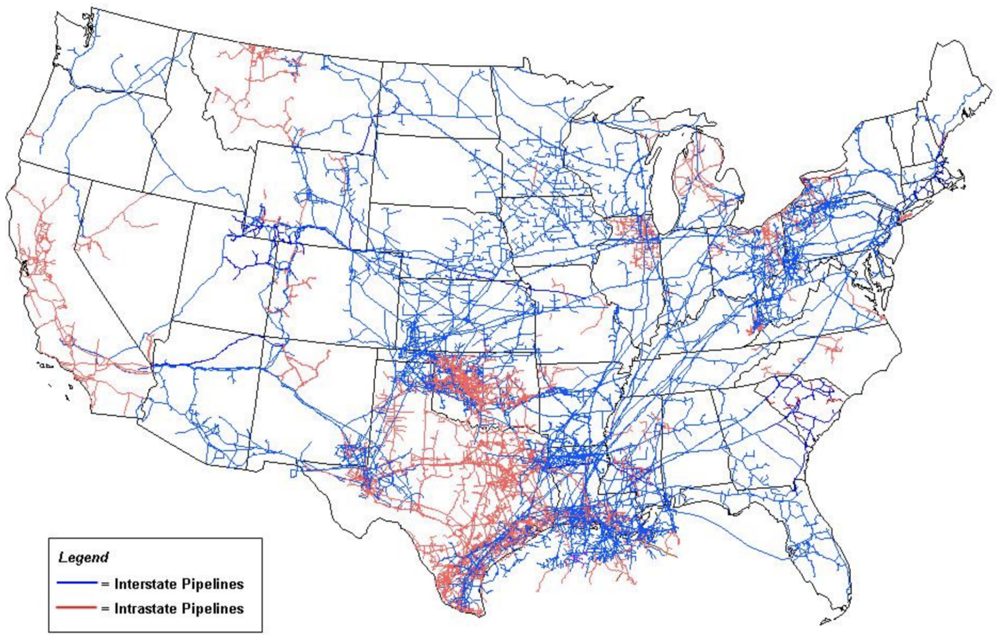

Figure 4. U.S. natural gas transmission pipeline system, 2009 (U.S. Energy Information Administration 2009).

measured in the relevant service environment, the fitness-for-service process is largely unchanged for a hydrogen-containing system; only the material property inputs are different. Moreover, the material properties of line pipe steels in gaseous hydrogen are relatively consistent across American Petroleum Institute grades. More work is necessary to establish the bounds on the consistency of fatigue and fracture properties in gaseous hydrogen environments. If general trends can be firmly established, however, then the principal unknowns become the state of the line pipe structure (e.g., defects, damage, state of the welds) and externally applied stresses and strains. In short, based on current state of knowledge of material properties, fitness for service is determined principally by the uncertainty of (1) the quality and reliability of the manufactured pipe (such as, the number of latent defects), (2) the operating conditions (such as, pressure cycle), and (3) external influences (such as, ground movement); in contrast, hydrogen impacts on common pipeline steel grades play less of a determining factor.

Fatigue crack growth rates are known to substantially increase in the presence of hydrogen (Cialone and Holbrook 1985; Nanninga et al. 2010; San Marchi et al. 2010, 2011; San Marchi and Somerday 2012; Somerday et al. 2013; Slifka et al. 2014; Ronevich and Somerday 2016a; Ronevich and Somerday 2016b; Ronevich, Somerday, and San Marchi 2016; Meng et al. 2017; Briottet et al. 2012). This trend has been shown to extend to low hydrogen partial pressures; for example, Ronevich and San Marchi (2021) show significant effects of hydrogen on fatigue crack growth at partial pressure near 1 bar. For high stress intensity factors (which depends on several factors, but generally for $\Delta K > 20$ MPa $m^{1/2}$), the fatigue crack growth is independent of pressure, meaning hydrogen partial pressure of 1 bar is about the same as for partial pressure of 200 bar (Ronevich and San Marchi 2021). Similar results were established in Meng et al. (2017). However, hydrogen gas pressure does affect fatigue at low stress intensity factor range (low ΔK); the fatigue crack growth scales approximately with the square root of pressure. Rigorously, the pressure should be replaced with the fugacity; see Ronevich and San Marchi (2021) and San Marchi, Shrestha, and Ronevich (2021) for an explanation of fugacity and this trend.

Interestingly, the fatigue crack growth in gaseous hydrogen is not dependent on the steel grade, as shown in Figure 5. All grades seem to show similar fatigue crack growth rates for the same hydrogen gas pressure. Consequently, general fatigue crack growth relationships for steels in gaseous hydrogen have been developed (Ronevich and San Marchi 2021; San Marchi, Shrestha, and Ronevich 2021; San Marchi et al. 2019), as represented by the dashed line in Figure 5. Whereas the grade of steel seems to be secondary, a distinct effect of stress is observed on fatigue crack growth in gaseous hydrogen as observed by the dependence on the load ratio R and the two-part fatigue crack growth relationship (high ΔK representing high stress):

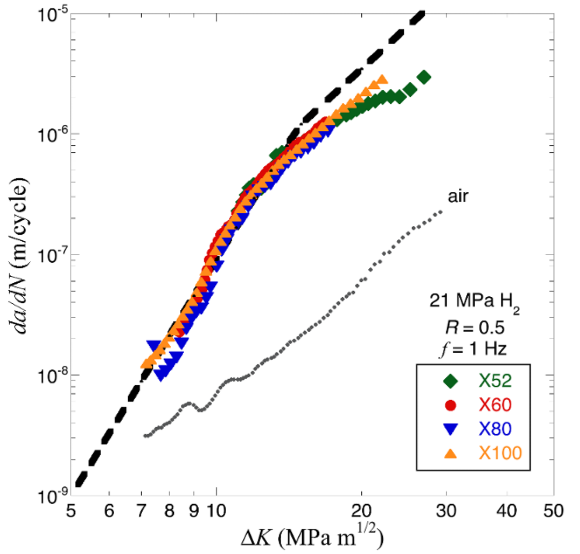

Figure 5. Fatigue crack growth of a diverse range of pipeline steels in gaseous hydrogen (San Marchi and Ronevich 2022).

$$\text{For high } \Delta\text{K}: \quad \frac{da}{dN}[\text{m/cycle}] = 1.5 \times 10^{-11} \left(\frac{1+2R}{1-R}\right) \Delta K^{3.66} \tag{3.1}$$

$$\text{For low } \Delta\text{K}: \quad \frac{da}{dN}[\text{m/cycle}] = 7.6 \times 10^{-16} \left(\frac{1+0.4286R}{1-R}\right) \Delta K^{6.5} f^{1/2} \tag{3.2}$$

where crack growth rate ($\frac{da}{dN}$) is the lower of the two values for a given stress intensity factor range (ΔK in units of MPa), the load ratio (R) is defined as $\frac{K_{\min}}{K_{\max}}$, and f is the fugacity (in units of bar) of the gaseous hydrogen (Ronevich and San Marchi 2021; San Marchi, Shrestha, and Ronevich 2021). Various forms of these equations exist in the literature, but they are all consistent with San Marchi et al. (2019). The transition between the two $\frac{da}{dN}$ relationships depends on R and f and can be determined for given R and f by setting the two equations equal and solving for ΔK. The observation that different grades of pipeline steel show similar fatigue crack growth in hydrogen should not be surprising, since API 579/ASME FFS-1 provides Paris Law relationships for fatigue crack growth rate in air or non-aggressive environments that are generic to the class of steel (not the grade), such as ferritic steels or ferritic-pearlitic steels. In short, hydrogen seems to amplify the effect of stress through the load ratio, but otherwise hydrogen affects all grades of pipeline steels similarly for the same hydrogen gas pressure. Hydrogen gas pressure is an important variable, but the pressure (fugacity) effect on fatigue can be generalized for all pipeline grades, as show in the simple $\frac{da}{dN} - \Delta K$ relationships provided above.

The fracture resistance (or fracture toughness) in gaseous hydrogen shows more variability associated with the steel pedigree than fatigue crack growth. Newer, high-quality steels are generally associated with greater fracture toughness, although in hydrogen vintage and modern steels are relatively similar (Ronevich, Shrestha, and San Marchi 2022). The available fracture data (measured in hydrogen) are generally limited; however, these data show a general decreasing trend in fracture resistance with increasing tensile strength, as shown in Figure 6 (after Ronevich et al. (2021)). The effect of pressure on fracture resistance is assumed to follow a square root dependence on fugacity (San Marchi et al. 2011; San Marchi, Shrestha, and Ronevich 2021), resulting in a steep decrease of fracture resistance at low partial pressure and a comparatively modest decrease at higher partial pressure (San Marchi et al. 2011; Briottet and Ez-Zaki 2018).

The fatigue (Ronevich, D'Elia, and Hill 2018) and fracture (Ronevich et al. 2021) properties of welds are generally consistent with the base metals. When residual stress in the test articles is appropriately considered, fatigue crack growth rates of welds are essentially identical to the base metals (Ronevich, D'Elia, and Hill 2018). This result should not be surprising since the fatigue response is not substantially affected by the details of the steel, as demonstrated in Figure 5. The fracture resistance of welds should consider the local strength of the weld. In Figure 6, the

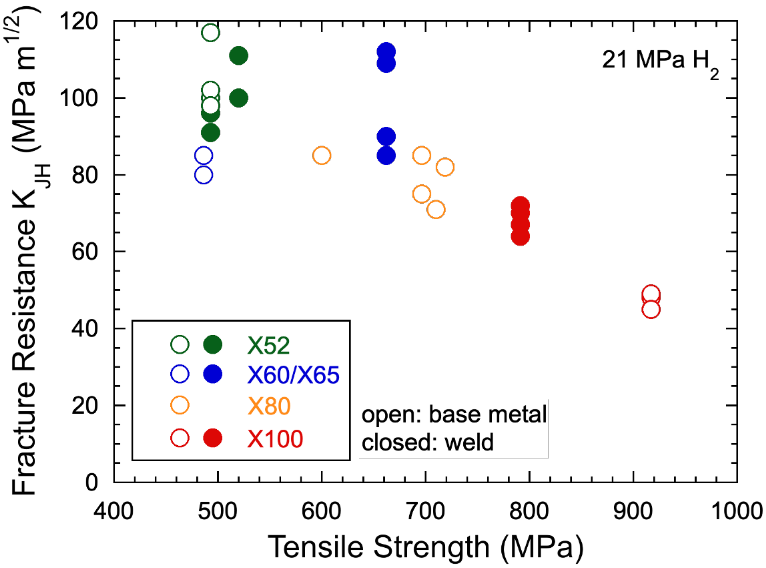

Figure 6. Fracture resistance of base metal and weld fusion zones of a range of American Petroleum Institute (API)-grade pipeline steels in gaseous hydrogen at pressure of 21 MPa (after San Marchi and Ronevich (2022)).

strength of the welds was measured (or inferred from hardness), and the trend appears coincident with the base metals. The response of a weld in a structure, however, will depend on the details of the structure, such as residual stress in the structure, over-matching or under-matching of the strength relative to the base metal, and potential welding defects. It should be noted that the bulk of the tested steels and welds are modern (i.e., post-1990s), although a few vintage steels have been tested in hydrogen and follow the same trends. Lastly, for these vintage pipe steels, the manufacturing methods and available quality control technology resulted in significantly more latent defects in the longitudinal seams. As over half of the natural gas pipelines in operation in the United States were installed before the 1970s, there is a need to evaluate the fatigue and fracture behavior of the vintage pipes and welds to elucidate their behavior.

Considering that over 1,600 miles of dedicated gaseous hydrogen pipeline exist in the United States (American Society of Mechanical Engineers 2005), it should be clear that conveyance of hydrogen by pipeline is possible. As the description above asserts, the fatigue and fracture properties of pipeline steels and their welds do not vary substantially based on the pedigree of the material. The pedigree of the structure, however, is another matter. Defects in the structure and operational conditions vary substantially from one line to another, and these characteristics will determine the appropriateness of the structure for conveyance of hydrogen (American Society of Mechanical Engineers 2005, 2007). Moreover, hydrogen has a pronounced effect on fatigue and fracture properties, but the influence of partial pressure is relatively modest; thus it seems unlikely that the percentage of hydrogen in the system will be a determining factor on the structural integrity of the line pipe.

3.1.2 Pipeline Transport

Previous literature has extensively examined the performance impacts of injecting hydrogen into the natural gas transmission pipelines (Schouten 2004; Blacharski et al. 2016; Witkowski et al. 2018; Zabrzeski et al. 2019; Kuczyński et al. 2019; Abbas et al. 2021). Just as mixture thermodynamic and transport properties discussed in Section 2 change with increasing blends of hydrogen, so do pipeline operating conditions. Design parameters such as pipeline inner diameter, pipe roughness, and elevation change also affect pipeline operating conditions. Although prior studies use various approaches in modeling transmission pipeline systems with increasing hydrogen composition, general trends of effects are inferred as they relate to pipeline transport. The effects discussed in this section include trends observed in network capacity, pressure drop, and temperature change.

Blending hydrogen can have systemic performance impacts on pipeline operation and gas end-use due to the differences in natural gas and hydrogen physical properties. For example, the energy transmission capacity for a single transmission pipeline falls as more hydrogen is blended into it (Bainier and Kurz 2019). This effect could introduce bottlenecks in the greater pipeline network's operation and is primarily attributed to hydrogen's lower volumetric energy density compared to that of natural gas. Note, however, that while natural gas is approximately three times more energy dense than hydrogen on a volumetric basis, Bainier and Kurz (2019) found that with fixed pressure drop, the energy transmission capacity at 100% hydrogen concentration is only 15%–20% lower than the energy transmission capacity of pure natural gas, indicating that flow velocity increases with hydrogen blend ratio in such scenarios. Maintaining constant energy transmission capacity would likely require increasing the operating pressure of the pipeline to drive a higher flow rate (Tabkhi et al. 2008); however, pipeline operating pressure will likely need to be reduced due to the impacts that hydrogen has on steel material integrity documented in the previous section of this review and regulated by ASME B31.12 (American Society of Mechanical Engineers 2020). Line pack sees a more substantial reduction in overall capacity than pipeline energy transmission. Haeseldonckx and D'haeseleer (2007) and Gondal and Sahir (2012) modeled line-pack energy storage as a function of hydrogen blend ratio and found that stored line-pack energy decreases with increasing hydrogen composition up to 60% by volume for their respective case studies. Reductions in line-pack capacity can inhibit transmission network flexibility because less energy can be stored within the pipeline network. To compensate for the reduction in transmission capacity, pipeline operators can increase gas flow rates to maintain consistent energy delivery. Increasing flow rates, however, results in increased pressure drops along the pipeline, which could in turn require higher pipeline pressure to maintain the delivery pressure required at city gates and by other end-users (Allison et al. 2021). The ability to maintain energy transmission capacity will depend on equipment and network constraints.

Maintaining a consistent energy transmission rate while increasing hydrogen concentration will increase compression power requirements, which will likely require modifications or replacements at pipeline compression stations and/or additional compressor station locations to manage maximum allowable pipeline pressure. This is significant because compression accounts for the majority of energy used to transport natural gas and meet end-user pressure and flow requirements. Pressure drop is a function of a variety of pipeline properties and conditions that change with gas composition, including fluid flow rate, gas density, friction factor, and average gas temperature. Several prior publications have reported on the impact of hydrogen on pipeline pressure drop on either a constant volumetric flow rate (Blacharski et al. 2016; Witkowski et al. 2018; Kuczyński et al. 2019), constant energy transmission basis (Allison et al. 2021) or both (Schouten 2004). Blacharski et al. (2016) and Witkowski et al. (2018) studied the impact of different blending compositions on transmission pipeline pressure drop. The results of their studies show that with a constant standard volumetric gas flow rate, increasing hydrogen content reduces pressure drop. This is primarily attributed to the lower mixture density, higher compressibility factor, and lower mixture viscosity with increasing hydrogen content (Blacharski et al. 2016; Witkowski et al. 2018). It is important to note, however, that although pressure drop reduces with increasing hydrogen concentration at constant volumetric flow rate, total energy flow rate also reduces due to the lower volumetric energy density of hydrogen. The studies found that for a constant energy flow rate, pressure drop increases with increasing hydrogen content until an apex at 70%–85% hydrogen by volume, after which pressure drop decreases (Allison et al. 2021). These results are consistent with those found by Bainier and Kurz (2019), which illustrate that with fixed pressure drop, volumetric flow increases with hydrogen concentration.

Managing pressure along the pipeline is necessary not only for maintaining pressures for end-users, but also for limiting gas flowing velocities. Gas density decreases as pressure reduces along the pipeline length, resulting in increased fluid velocity. Allowing pipeline fluid velocities to exceed the erosional velocity can result in compromised pipeline integrity. Blacharski et al. (2016) and Witkowski et al. (2018) also include gas velocity in their analyses. Their results show that gas velocity reduces with increasing hydrogen composition when considering constant volumetric gas flow rate scenarios (which, as discussed previously, have reduced energy flow rates). Erosional velocity also increases for less-dense gas mixtures; as a result, this velocity is not approached in constant volume flow rate scenarios where hydrogen content increases (American Society of Mechanical Engineers 2019). This constraint may be relevant for maintaining energy delivery via increasing gas flow rates, because increased pressure drop along the pipeline will lead to increased gas velocities (Abbas et al. 2021). Erosional velocity constraints may also be relevant for constant pressure drop operation, because the increase in volumetric flow rate with hydrogen concentration for constant pressure drop scenarios seen in Bainier and Kurz (2019) could only be achieved via an increase in flow velocity. It is worth noting, however, that the commonly used API RP 14E erosional velocity equation is often considered overly conservative and inappropriate for many applications, as it is intended for use in "design and installation of new piping systems on production platforms located offshore" (Sani et al. 2019). Many alternatives tend to focus on deriving velocity limits in the presence of solid particles, which is a greater concern for oil production than for transmission of gaseous mixtures. As such, more research may be necessary to determine how to best evaluate the erosional velocity for hydrogen-natural gas mixtures.

The addition of hydrogen can also cause changes to other mixture thermodynamic and transport properties, which can in turn indirectly influence pressure drop and line-pack capacity. Changes to mixture properties such as heat capacity and Joule-Thomson coefficient affect fluid heat transfer and thermodynamics, resulting in variations in temperature along transmission pipelines. Kuczyński et al. (2019) analyzed the impact of hydrogen blending on thermodynamic and transport properties in medium-pressure pipelines. They observe that the temperature gradient increases with increasing hydrogen content until equilibrium is eventually achieved once the gas reaches ambient temperature (Kuczyński et al. 2019). It should be noted that the necessity of considering thermal effects in analyses depends on the accuracy required by the modeling application. Transient pipeline analyses used to reconcile pipeline operations warrant a high degree of accuracy, whereas steady-state analyses used for project screening may be able to tolerate inaccuracies resulting from the isothermal assumption. Osiadacz and Chaczykowski (2001) present a comparison of isothermal and non-isothermal assumptions in both steady-state and transient gas network analysis and determine relative errors between both assumptions. This study states that the isothermal assumption is not valid for transient simulations, as heat transfer between the pipeline and its surroundings is not instantaneous.

3.1.3 Gas Compression

Centrifugal and reciprocating compressors are the two technologies that provide the compression necessary to compensate for pressure drop along transmission pipelines. Major factors that determine technology selection between the two compressor types include the flow rate capacity and operational flexibility required for compression (Interstate Natural Gas Association of America 2010; Diez et al. 2020). Applications that require high flow rate, medium pressure ratio, and/or limited flow variation tend to favor centrifugal compressors. Conversely, applications that entail low flow rate, high pressure ratios, and/or variable pipeline conditions benefit from utilizing reciprocating compressors. Reciprocating compressors are a proven method for compressing hydrogen and are widely used in refineries due to their excellent flexibility for handling gases with different molecular weights (though seals require additional attention for low-molecular-weight gases such as hydrogen). They can be oil-lubricated or non-lubricated, the latter of which is preferred for high-purity hydrogen applications to avoid oil contamination (Diez et al. 2020). Centrifugal compressors, on the other hand, are often tailor-made for specific projects; because their aerodynamic design requires balancing performance at the design point with breadth of the operating window, they tend to be more sensitive to changes in fluid properties (Diez et al. 2020). Important considerations for assessing either type of compressor for reuse with hydrogen include compatibility of the compressor materials with hydrogen at process pressure and temperature, the effect of hydrogen on performance and the operational envelope of the compressor, the acceptability of hydrogen stream contamination with lubricant (more important for pure hydrogen applications), and the acceptability of hydrogen losses through seals (Diez et al. 2020). Limitations to compressor speed and/or power input could also affect either type of compressor. The following sections discuss general effects of hydrogen blending on both types of compressors and effects of hydrogen blending that are specific to centrifugal compressors.

General Effects to Compression

Several effects of blending hydrogen relating to compression thermodynamics can impact both reciprocating and centrifugal compression technologies. Compression work and theoretical temperature rise both increase with hydrogen concentration when considering compression at constant pressure rise and inlet temperature (Bainier and Kurz 2019; Zabrzeski et al. 2017). The increase in compression work is primarily attributed to the decrease in density, while the increase in temperature rise is due to an increase in heat capacity ratio (the ratio of the specific heat at constant pressure to the specific heat at constant volume) as gas composition changes. Both of these effects could limit compression station capacity. The increased compressor work required to maintain a constant pressure ratio may lead to scenarios where a compressor station is power-limited by the compressor motor or turbine. Likewise, the increased temperature rise from compression for gas mixtures with higher hydrogen composition may lead to scenarios limited by cooling duty if compressors are staged in series to achieve a given compressor station outlet pressure. The effect of these scenarios may or may not limit the overall pipeline network's capability for blending, depending on whether or not network operators can shift compression loads from one station to another.

Effects Exclusive to Centrifugal Compressors

Surge and choke are two potential phenomena that could impact centrifugal natural gas compressors with addition of hydrogen, depending on how the compressor is designed and operated. Surge is an unstable condition in which fluid flow reverses directions cyclically and is caused by insufficient inlet flow rate (Compressed Air and Gas Institute 2016). Choke, or stonewalling, occurs on the other end of the compressor performance envelope at high flow rates when the velocity of the fluid in the compressor reaches the speed of sound. Centrifugal compressors are characterized by a relationship between pressure rise, flow rate, efficiency, and speed that is often captured by a compressor performance map that denotes conditions such as surge and choke. These performance maps typically show isentropic head and/or compressor efficiency as a function of volumetric flow rate and compressor speed. While performance maps can be non-dimensional, the operating data that they provide are often specific to a design point based on fluid properties and equipment conditions at a nominal flow rate, inlet and outlet pressure, inlet temperature, and compressor speed. Off-design gas mixture compositions can impact the inlet fluid density and therefore inlet volumetric flow rate, which in turn could push the compressor operation toward an off-design operating condition that could result in surge or choke, depending on the flexibility of the compressor and how it is operated. Variable-speed centrifugal compressors might have sufficient flexibility to avoid surge and choke, particularly if they are powered by a variable-speed drive electric motor; Bainier and Kurz (2019) illustrate that a centrifugal compressor with some speed margin can maintain a consistent pressure rise by increasing speed, without approaching surge or choke conditions. For fixed-speed machines, adjusting inlet guide vanes can provide an alternative means of flexibility, and performing controlled surge testing in new operating conditions in re-rate projects is critical to avoid adverse operating conditions (Sorokes, Kaulius, and Memmott 2014).

Maximum impeller speed is another centrifugal compressor characteristic that could limit hydrogen blending. Bainier and Kurz (2019) and Alban (2022) provide examples of how impeller speed can change with increasing hydrogen concentration. Both studies model centrifugal compressors with off-design performance maps for scenarios with increasing hydrogen concentration in a blend of hydrogen and natural gas. Alban (2022) shows that for a scenario with constant volumetric flow rate, impeller speed changes marginally when compressing gas mixture with increasing hydrogen composition up to 20% by volume. Alban (2022) also shows that for a constant energy throughput scenario, impeller speed must increase substantially and will exceed safe operating limits when compressing natural gas mixtures with only 10% hydrogen composition, based a maximum operating speed of 105% of design speed in accordance with API 617. Similarly, Bainier and Kurz (2019) illustrate a significant increase in required impeller speed to accommodate increasing hydrogen blends when holding compressor pressure rise constant; however, the specific compressor modeled in their study could tolerate just under 20% hydrogen before exceeding the maximum allowable operating speed. They also note that increasing hydrogen concentration to 100% requires substantially more power when maintaining a consistent pressure rise (Bainier and Kurz 2019). Zhang et al. (2021) analyze centrifugal compressor performance in the context of blending hydrogen into natural gas pipelines and find that compressor speed must be increased to maintain a consistent energy flow rate. The reduction in mixture gas molecular weight (and thus density) is the primary driver of this trend, though the impacts of hydrogen on pipeline pressure drop and compressor head rise can also have an effect. Hydrogen embrittlement of the impeller could further limit the maximum compressor speed (Diez et al. 2020) and impact compressor integrity (Alban 2022). Adam, Bode, and Groissboeck (2020) discuss the option to replace the impeller and other compressor internals with those designed for greater hydrogen compositions as a inexpensive alternative to a complete compressor replacement. Alban (2022) notes that API 617 prohibits the use of steel materials with yield strengths greater than 827 MPa (or 120 ksi) for centrifugal compressors processing gases with hydrogen partial pressures greater than 6.89 bar. Blistering, in which hydrogen diffuses through the material and creates local pressure buildup at inclusions or grain boundaries and promotes crack propogation, is another concern for centrifugal compressors processing gas mixtures containing hydrogen (Alban 2022).

3.1.4 Prime Movers

Prime movers are the technology that power compression equipment. Gas-driven turbines, reciprocating engines, and electric motors are examples of common prime movers employed for transmission pipelines. The compressor technology employed largely dictates the prime mover technology chosen. Centrifugal compressors operate with natural gas turbines, while reciprocating compressors pair well with gas-driven internal combustion engines. Electric motors work well for powering both types of compressors. Gas-driven prime mover performance is assessed in terms of emissions, energy conversion efficiency, and equipment reliability, all of which are impacted by the presence of hydrogen in prime mover fuel. This section focuses on how hydrogen blending impacts the performance characteristics of both gas-driven turbines and internal combustion engines, as these technologies are frequently employed along the natural gas transmission pipeline (Brun 2018).

Blending hydrogen reduces the volumetric energy density of the fuel used in prime movers, which in turn can reduce the power output capacity of those prime movers and limit compressor station capacity (Domptail et al. 2020). This further exacerbates the impact on capacity created by the higher compressor load associated with compressing natural gas mixtures with hydrogen blends. However, there are several options for addressing the reduction in prime mover power capacity. Increasing prime mover fuel flow rate can compensate for the reduction in fuel energy density, and increasing the loading of underutilized prime movers can reduce the load requirements on fully utilized prime movers. This may necessitate modifying prime mover fuel accessories to enable larger volumetric flow rates (Kutne et al. 2020; Goldmeer 2019). Replacing gas turbines or internal combustion engines with electric motors is another retrofit option that avoids the challenges associated with prime mover fuel energy density. The decision to either modify operations of combustion-powered prime movers or retrofit compression stations with electric motors will depend on economics, reliability, and compatibility with whatever modifications to the compressor are necessary.

Gas Turbines

Gas turbine systems have either diffusion or lean premixed flame type combustion systems. Diffusion combustion systems burn fuel at or near stoichiometric ratios with air to produce a stable flame with high peak temperatures. Although these systems are fuel-flexible, they can produce high NO_x emissions and may require an emissions control technology such as water/steam injection with fuel and/or selective catalytic reduction (Termaath et al. 2006). Lean premixed systems, on the other hand, have high air-fuel ratios and controlled operating conditions for low NO_x emissions, high efficiency, and reliable service. Lean premixed systems are heavily optimized in terms of equipment design and control, which lends to limitations in fuel flexibility. Hydrogen impacts both diffusion and lean premixed flame combustion system technologies differently in terms of NO_x emissions and fuel compatibility (Kroniger, Lipperheide, and Wirsum 2017; Mohammad et al. 2020; Abbott, Bowers, and James 2012).

NO_x emissions are a major concern for both gas turbine manufacturers and operators, as these emissions are regulated in federal code (EPA 2006). NO_x emissions are primarily influenced by combustion temperature, which could be impacted by a fuel's hydrogen composition. Without an emissions control technology, diffusion combustion systems are poorly suited for hydrogen-blended natural gas fuels because the presence of hydrogen increases turbine combustion temperatures, which in turn increases NO_x emissions exponentially (Kroniger, Lipperheide, and Wirsum 2017). NO_x emissions may also increase for lean premixed flame combustion systems using natural gas fuels with increasing hydrogen composition. However, Mohammad et al. (2020) observe that this emissions effect is not significant in hydrogen compositions up to 25 vol % where combustion temperatures are controlled.

In contrast to diffusion combustion system gas turbines, lean premixed combustion gas turbines have less fuel flexibility. Lean premixed gas turbine manufacturers typically state that unmodified legacy turbines can handle fluctuations of 2%–5% of the tuned Wobbe Index and greater than 10% if re-tuned and modified (Abbott, Bowers, and James 2012). This suggests that lean premixed gas turbines should be able to accommodate small quantities of hydrogen in the natural gas mix. Greater amounts of hydrogen in natural gas fuels could create destabilizing operational phenomena on unmodified legacy turbines such as excessive combustion dynamics, flashback, and flame blowout (Kurz et al. 2019; Abbott, Bowers, and James 2012). These phenomena occur because the addition of hydrogen to natural gas shifts flame configurations for turbine burners. Sensitive burners can experience flame liftoff, which can lead to intermittent blowout and increased carbon monoxide emissions. Abbott, Bowers, and James (2012) demonstrate these effects in practice by observing and documenting abnormal turbine operation during periods of low Wobbe Index. In other scenarios, flames can propagate into the burner mixing zone (flashback) and cause equipment damage. Tuccillo et al. (2019) illustrate that flashback can be a problem for lean-premixed combustors that employ a pilot flame, but is less of a problem for pseudo-Rich Burn, Quick Mix, Lean Burn (RQL) combustors supplied up to 20% hydrogen blends. These flame behaviors could also shift combustion acoustic frequencies to increase equipment wear. Hydrogen addition also raises flame temperatures, which can increase thermal stresses within the turbine combustion chamber and increase NO_x production (Tuccillo et al. 2019).

Lean premixed gas turbine system retrofit potential depends heavily on the equipment modifications necessary to facilitate wider fuel flexibility. Lean premixed gas turbine vendors are in the process of developing retrofit solutions to allow legacy turbines to accommodate hydrogen, in addition to providing new build technology options that are more tolerant to hydrogen (Diez et al. 2020; Kutne et al. 2020). Approaches for retrofitting include developing more sophisticated control systems to account for gas composition and/or turbine conditions, as well as implementing improved combustion systems for increased resilience against the aforementioned adverse operation effects (Goldmeer and Catillaz 2021; Forte et al. 2008; Wind, Güthe, and Syed 2014; Larfeldt et al. 2017). A potential retrofit project for a legacy gas turbine will likely include combustion module replacement, modified instrumentation/control systems, and a modified fuel delivery system (Kutne et al. 2020).

Reciprocating Engines

Reciprocating engines have fewer fuel flexibility limitations than gas turbines. Hydrogen addition, however, does impact engine operation through several undesirable effects such as detonation, misfiring, engine knock, and increased emissions (Polman et al. 2003). Compression station operators can mitigate these effects through engine adjustments such as tuning ignition timing, fuel intake, and air intake. Much existing literature investigating the addition of hydrogen to engine fuels focuses on automotive engines. While some of the implications may translate to natural gas reciprocating engines, this section focuses on research studies of natural gas engines utilized for pipeline and industrial use.

Korb, Kawauchi, and Wachtmeister (2016) and Wahl and Kallo (2020) quantitatively assess the effects of blending hydrogen up to 30% and 20% by volume, respectively, into natural gas on medium- and high-speed large bore engines. Both studies report significant shifts in engine operating windows toward leaner fuel/air mixtures and delayed ignition timing to compensate for adverse effects such as engine knocking and fuel pre-ignition. Both studies also find that hydrogen addition improves engine NO_x and hydrocarbon emissions, as well as efficiency, as long as adjustments to ignition timing and air/fuel intakes are made. The combustion of energetically active hydrogen molecules enables greater extents of reaction at higher hydrogen blend ratios, and therefore fewer hydrocarbon emissions. Greater NO_x emissions can result from combusting fuels with high hydrogen content due to higher combustion temperatures, but this can be mitigated by operating with leaner fuel/air mixture conditions.

3.1.5 Pressure Reduction

Gas transmission networks employ pressure reduction systems at points of the network where the high-pressure transmission line connects to lower-pressure systems associated with distribution or end-use. Adding hydrogen will affect the magnitude of the temperature change seen across these pressure reduction systems because hydrogen and natural gas have different Joule-Thompson coefficients, which indicates the rate of change of temperature relative to the rate of change of pressure. Natural gas normally experiences a temperature drop with a reduction in pressure and therefore requires heating to offset potential condensation of hydrocarbons in the pipeline (Schouten 2004). Hydrogen, on the other hand, has a negative Joule-Thompson coefficient and experiences temperature rise with a reduction of pressure (Bainier and Kurz 2019). Schouten (2004) finds that a gas mixture with 25 mol % hydrogen results in a 33% lower temperature change relative to that experienced by natural gas without hydrogen. Li et al. (2021) further investigate the effect of hydrogen on natural gas mixture Joule-Thompson coefficient by varying hydrogen composition up to 30 vol %. This study's results agree with the findings of Schouten (2004) and indicate that the Joule-Thompson coefficient for blends of natural gas and hydrogen decreases with increasing hydrogen compositions for the studied composition range.

Limited information exists for discerning the effect of increasing hydrogen blending on pressure regulator performance. One report discusses how regulator capacity depends on whether process and fluid conditions result in choked flow (Polman et al. 2003). If choking occurs, mass flow rate through the regulator depends on upstream pressure, fluid density, and the cross-sectional area of the orifice. Polman et al. (2003) model a pressure regulator at choked flow, ideal conditions, and increasing hydrogen volume content of the fluid. This study determines that the pressure regulator mass flow capacity at choked flow reduces with increasing hydrogen content.

3.1.6 Meters

Pipeline gas flow is measured at various locations in the transmission pipeline network using inferential flow meters. Inferential flow meters have specified operating ranges for composition, temperature, and pressure for which they are accurate. Operation outside of inferential flow meter specifications could lead to measurement errors and result in negative economic impacts due to inaccurate custody transfer and degraded network control. The difficulty in correcting measurement inaccuracies depends on whether the gas composition is static or dynamic. For pipelines operating with static off-design gas compositions, inferential flow meters can be re-rated to correct measurement inaccuracies. It is more difficult to rectify flow meter measurements if pipeline gas composition is dynamic. Inaccuracies introduced by dynamic off-design gas compositions can be addressed by flow compensation algorithms, but this approach requires additional and frequent pipeline measurements in temperature, pressure, and composition for improved accuracy.

Orifice flow meters are one of the most common inferential flow measurement devices used for natural gas transportation systems. The accuracy of this technology could be susceptible to changes in pipeline gas composition, as metering depends on a measured specific gravity (Emerson Process Management 2005). Data processing algorithms can compensate for flow measurement inaccuracies but would entail additional temperature, pressure, and composition measurement inputs. Polman et al. (2003) provide an example in estimating measurement deviation over varying hydrogen compositions for orifice and other inferential flow meters. A technical report by NewGasMet (2021) tests effects from flowing hydrogen admixtures through rotary flow meters at 9 bar and 16 bar. The report concludes that the error in measurement was insignificant for admixtures of less than 20% by volume.

GRTgaz (2020a) discusses the effects of hydrogen blending on turbine and ultrasonic flow meters and determines that both remain within accuracy limits for hydrogen blending ratios less than 10% by volume. It is noted that the demonstration tested these meters at pressures and flows lower than what is seen in transmission pipelines. Both ultrasonic and turbine flow meters can be subject to inaccuracies, as both rely on specified thermodynamic properties that can fluctuate in operation with varying hydrogen composition (Emerson Process Management 2005; Grimley 2018). The data processing algorithms discussed to compensate flow measurement inaccuracies for orifice flow meters could be similarly applied to turbine flow meters. Measurement uncertainties for these flow meters can also arise when fluid velocities exceed meter design specifications (Diez et al. 2020).

3.1.7 Valves

Depending on regulations, mainline valve stations are spaced 5–20 miles apart for the purpose of isolating a pipeline segment for maintenance (American Society of Mechanical Engineers 2019). Because hydrogen is the smallest molecule, it presents challenges for leakage management and affects the material integrity of pipeline components. Leakage across a valve can occur in two ways: through the seat and through the stem (Sequeira 2012). These leakage pathways lead to challenges in equipment isolation and fugitive emissions, respectively.

Metal-to-metal technology is preferred for preventing leakage at the valve seat, which requires a flexible and resilient metal disk that provides a seal with a Stellite hard-faced seat (Sequeira 2012). Valve packing and gasket design considerations are key to prevent leakage at the valve stem. Commonly used materials such as soft graphite are permeable to hydrogen gas and are ineffective against leakage. Hard metal and precisely machined gaskets are necessary to create an effective seal. Packing designs employing rubber O-rings or chevron-type packs for creating multiple seals are suitable for hydrogen service below 200°C. It should be noted that a gas transmission operator in the the Netherlands, Gasunie, conducted leak and seat tests as well as blowdown operations under hydrogen on valves originally used for natural gas service and determined them to be safe and can be used for 100% hydrogen (Huising and Krom 2020).

Hydrogen embrittlement also influences valve selection decisions. Reducing the prevalence of stress concentrations caused by sharp edges and abrupt angles created during the valve manufacturing stage could mitigate this effect (Sequeira 2012). Welding on valves should also be limited because embrittlement is most likely to occur at those locations.

3.1.8 Gas Composition Analysis

Hydrogen blending scenarios could range from very small injection quantities (e.g., 1% by volume) to 50%+ hydrogen by volume on up to 100% hydrogen. Accurately identifying gas composition is important for all of these scenarios to ensure that the blend ratio stays below technical limits given modifications made to the system and to ensure accurate billing and tracking of gas heat content. Gas chromatography provides the primary method for determining pipeline gas composition and calorific values in order to ensure billing and network control (Diez et al. 2020). This technology detects gas mixture component concentrations by analyzing differences in component thermal conductivities and gas mobilities. Current gas chromatography methods employed on natural gas networks utilize helium as a carrier gas. Measurement inaccuracies can result from using helium, as it has a similar thermal conductivity to hydrogen (Weidner et al. 2016). Alternative methods for measuring hydrogen within a natural gas mixture include using a single-column gas chromatograph with argon as the carrier gas or a dual-column gas chromatograph with helium and argon as carrier gases (Domptail et al. 2020). Sensors are another developing technology to detect hydrogen, in conjunction with conventional gas composition analysis methods or with sensors detecting other hydrocarbon compounds (Sweelssen et al. 2020). Blokland et al. (2021) developed a platinum-based sensor to reversibly detect hydrogen in natural gas. This technology was demonstrated in the HyDeploy project and was shown to detect hydrogen in gas mixtures up to 30 vol % composition at pressures up to 10 bar.

3.1.9 Pipeline Inspection, Leakage, and Facility Codes and Standards

Pipeline inspection and facility codes and standards considerations are often overlooked in academic analyses of hydrogen blending that focus on materials or system-level economics. However, these factors could contribute significantly to the cost of readying natural gas pipelines to operate with hydrogen. Because the quantity and severity of preexisting defects and cracks is very important to the capability of a pipeline to operate with hydrogen, transmission pipeline operators will need to perform internal inspections of every meter of transmission line (for the credible threats) before greenlighting a conversion in order to identify any defects that must be addressed. Natural gas transmission pipelines are frequently inspected for overall integrity, and several tools exist to facilitate these inspections. In-line inspection (or "pigging") tools such as magnetic flux leakage are used to test for corrosion; electromagnetic acoustic transducer services identify cracks; low-field magnetic flux leakage detects hard spots; and geometric tools can find dents, gouges, and wrinkle bends generally associated with old manufacturing methods used on vintage pipes that are stable when operating with natural gas but may be susceptible to increased deterioration when operating with hydrogen. Some pipelines cannot currently accommodate in-line inspection tools due to old design and construction methods and would need to be modified to be "piggable" before hydrogen injection could be considered (Potts 2022). Furthermore, blending hydrogen into the transmission pipeline systems will likely necessitate increased internal pipeline inspection frequencies to reduce the risk of pipeline failure by identifying critical defects (Melaina, Antonia, and Penev 2013; Domptail et al. 2020) based on the assumption that hydrogen will reduce toughness and increase fatigue crack growth rates.

Flame ionization detection and differential absorption lidar are the gas detection technologies used in pipeline patrols to detect leakage from the pipeline system (Altfeld and Pinchbeck 2013). These patrols use leak detection equipment, are required to be conducted on an interval basis, and could be carried out by walking, driving, or helicopter survey (National Archives Code of Federal Regulations 2020). Altfeld and Pinchbeck (2013) mention that the accuracy of these gas detection technologies may be impacted by the presence of hydrogen in natural gas. They advise that using flame ionization detection or differential absorption lidar may be suitable for low concentrations of hydrogen blending up to 5% by volume and recommend technology modification to detect admixtures exceeding 10% hydrogen by volume. This advice is provided as a preliminary recommendation and warrants further investigation to clarify hydrogen's impact on gas detection.

Codes and standards qualifications for transmission line facilities such as compressor stations, meter stations, and pressure reduction stations must also be addressed. Compressor station buildings and facilities would need to be brought up to codes for fire, electrical classification, and other hazards that might change with the introduction of hydrogen. NFPA (2020) covers general hydrogen safety requirements for hydrogen technologies, including things like storage, generation, piping, and venting. Pipeline operators would likely need to assess metering stations on an individual basis and work with vendors to determine which stations would still work and which would need to be replaced (Potts 2022).

3.2 Distribution Pipeline Networks

Distribution pipeline networks comprise a series of steel and plastic pipes with valve, pressure regulating, and meter stations dispersed throughout (Melaina, Antonia, and Penev 2013). The back pressure of these networks is maintained from the city gate and through pressure regulating stations within the network that reduce pressure to meet end-user specification. The majority of meters are stationed at the end-users for billing purposes and thus require a high degree of accuracy.

Several key aspects differentiate natural gas distribution networks from transmission pipelines (Melaina, Antonia, and Penev 2013). First, distribution networks in the United States often operate at a lower pressure (up to 300 psi), have smaller pipe diameters (typically 1 to 2 inches), and are made of polyethylene or steel. Distribution networks in the United States consist of distribution mains, which vary in size between 1.5 and 8 inches in diameter, and service lines that have diameters typically between 0.5–2 inches. Distribution service lines in the United States also generally operate at pressures from as low as 0.25 psig (17.5 mbar) up to 60 psig (4.1 bar), with some operating at 100 psig (6.9 bar). Transmission lines, in contrast, typically operate between 1,200 psig (84 bar) and 600 psig (42 bar) (Melaina, Antonia, and Penev 2013). Note that pipe diameters and operating pressures might be different in other parts of the world.

3.2.1 Hydrogen Materials Compatibility of Polymer Line Pipe

To evaluate the compatibility of hydrogen and hydrogen blends with existing polyethylene (PE) pipeline materials, short-term mechanical, physical, and chemical effects along with a long-term lifetime (50+ years) assessment must be considered. This section reviews existing data of hydrogen effects on polyethylene materials and identifies gaps where additional testing or analysis is needed.

Existing data on short-term mechanical tests include mostly uni-axial stress states. Quasi-static tensile testing shows no significant effect from hydrogen at low pressures, but higher pressures result in a slight decrease in tensile stress and strain (Castagnet et al. 2012; Alvine et al. 2014; Castagnet et al. 2010; Klopffer et al. 2010; Menon et al. 2016). It is not yet known if this is due to pressure effects or hydrogen effects. Smaller-scale nanoindentation testing shows a decrease in local modulus of a PE specimen after hydrogen exposure (Simmons et al. 2021). Limited data on quick burst, mode I fracture energy, and fatigue tensile test results show no significant hydrogen effects (Castagnet et al. 2010; Simmons et al. 2021). Additional modes of fracture, along with defect-induced burst specimens and sharply notched fatigue tensile specimens, should be tested. For creep testing, one study found slightly lower deformation associated with hydrogen exposure (Castagnet et al. 2012). The results from this study are not purely experimental, and only one stress level was tested. Additional stress levels along with notched specimens should be tested to fully evaluate the impacts from operational field conditions. It is also recommended that multi-axial stress states in quasi-static, fatigue, and creep loading conditions be evaluated along with long-term testing for lifetime assessments with hydrogen.

There are some data available on hydrogen effects on physical properties of PE material, such as degree of crystallinity and density. The data show small changes in these properties with hydrogen exposure, although the trend between different grades of PE materials is not similar (Fujiwara et al. 2020; Fujiwara et al. 2021; Ono et al. 2019). Investigation into the crystallite morphology may be needed to further understand the physical changes. Nondestructive characterization techniques used in one study revealed less damage at the microscopic level associated with higher-density PE materials compared to lower-density PE materials after exposure to pressurized hydrogen (Ono et al. 2019). Multiple characterization techniques may need to be combined to fully evaluate the material changes at the molecular level as a result of hydrogen exposure. Quantification of the effect that these material changes have on the mechanical performance and lifetime of pipes would then be needed. In terms of material degradation, there are some oxidative induction time data available that suggest hydrogen does not contribute to the depletion of antioxidants in PE pipe materials (Iskov 2010). The data available include limited environmental conditions. Additional oxidative induction time testing should be completed that encompasses the environments associated with the entire operating envelope of PE pipelines, such as temperature, pressure, and the presence of contaminants in the gas.

The data summarized here have been generated on the body of pipe sections. Heat fusion joining of pipes is a common practice in the field, and the effects of hydrogen exposure in the joint region need to be fully evaluated. Additionally, the majority of the data discussed here were not traceable to a specific resin formulation. The effects of different resin formulations on compatibility with hydrogen also need to be evaluated.

3.2.2 Distribution Pipeline Transport

Like the transmission pipelines discussed previously, distribution pipelines must maintain delivery pressures at points of end-use to meet customer specifications. Operating methods to meet these specifications may require adjustments, depending on the degree of hydrogen blending and required gas flow rates. Smith et al. (2017) analyze pressure drop over 100-m-length of 25-mm-nominal-diameter steel pipe delivering a constant energy flow rate of gas. They find that with 30 vol % hydrogen, the mixture pressure drop is 25% higher than that of pure natural gas. The increased pressure drop must be considered when planning distribution network operations to ensure that the system still meets end-use requirements.

3.2.3 Leakage in Distribution Pipelines

Hydrogen leakage presents a key concern in distribution networks due to the low density and high diffusivity of hydrogen, particularly through polyethylene pipe walls. The majority of hydrogen leaks through polyethylene pipes would occur via permeation through the pipe walls, given the total pipe wall surface area in the system. Melaina, Antonia, and Penev (2013) note that this leakage could be 1.7 times the amount of natural gas leakage at a 20 vol % hydrogen blend under 60 psig of pressure; however, the total volume lost of 65.9 ft^3/mile/year in a 1-inch-diameter high-density polyethylene pipe is insignificant from an economic point of view. Haeseldonckx and D'haeseleer (2007) studied the impact of higher hydrogen blending amounts in natural gas pipelines in the U.K. and found that although the diffusion of hydrogen through polyethylene pipe walls is five times higher than for natural gas, the total amount of hydrogen leakage remains negligible, and annual losses account for only 0.0005%–0.001% of total volume transported. If measured on an energetic basis, the total loss is even smaller.

The effect on natural gas leaks as a result of introduction of hydrogen is another important consideration. Melaina, Antonia, and Penev (2013) note that a 20 vol % hydrogen blend into U.S.-grade plastic distribution mains operating at 60 psig doubles natural gas loss rates to 77 ft^3/mile/year. In another study by Subani, Amin, and Agaie (2017), increasing hydrogen blends beyond 20 vol % actually lowers gas leakage rates. They find, however, that the angle of the pipeline also plays a role in the leakage rate, and pipelines with an inclination of 15° exhibit higher leakage rates than those without an inclination at similar hydrogen blends.

Leakages through distribution pipeline joints can also cause concern, though to a lower degree than leakage through polyethylene pipe walls. The permeation coefficient of hydrogen, however, is greater in elastomers than plastic, and four to five times higher in plastic pipe than the permeation coefficient of natural gas (Melaina, Antonia, and Penev 2013). Elastomeric materials that are used in transport of gas include O-rings, diaphragms, gaskets, boots, flange, and quad seals. Hydrogen permeation in elastomeric materials reduces their tensile strength, therefore increasing the risk of leakage (Melaina, Antonia, and Penev 2013).

Safety hazards associated with hydrogen leakage in distribution systems arise primarily at end-use points—specifically in confined spaces or areas of low ventilation. The possible accumulation of hydrogen in confined spaces increases the probability and severity of an explosion, fire, or both. Methods for reducing the probability and severity of such incidences include the use of leak detection systems and odorants (Melaina, Antonia, and Penev 2013). One study suggests that the usage of NACE-compliant materials and fuel system seals, in addition to X-ray inspection services, would aid in reducing the risk of leaks (Kurz, Lubomirsky, and Bainier 2020).

Semiconductor-based gas detection devices or sensors are also used to detect the presence of leaks in both transmission and distribution pipeline systems. Hydrogen's impact on sensors could vary from sensor to sensor (Altfeld and Pinchbeck 2013). This impact likely requires more investigation, as Altfeld and Pinchbeck (2013) state that some sensors have heightened sensitivities to hydrogen while others will only react to the diluted gas components in detected gas mixture. If the effect of hydrogen on gas sensors is diluting, calibrating gas sensor alarm thresholds to the anticipated hydrogen composition may be sufficient for more accurate detection. Gas sensor manufacturers should be consulted as to how hydrogen affects the accuracy of their technology prior to sensor calibration.

Some research has been conducted on the use of odorants, such as the Hy4Heat project in the U.K. One study commissioned by the project published a technical report analyzing five odorant candidates that would be suitable for a 100% hydrogen gas grid. Of the five, the study concluded that odorant NB (which is 78% 2-methyl-propanethiol, 22% dimethyl suphide) (Murugan et al. 2020) would be a suitable candidate. Odorant NB provides a characteristic gas leak smell and shows no evidence of damage to pipelines or appliances. It is also the cheapest chemical and benefits from a low cost associated with changing current practices. One key concern, however, is that an additional purification step may be needed to ensure fuel cells are not damaged from consumption of the odorant. Another factor in accounting for suitability of an odorant is impact to human health and the environment. In this study, all the odorants were assessed using guidance from the European Chemicals Agency (ECHA), an EU agency responsible for implementing chemicals legislation to protect human health and environment. All odorants were deemed fit-for-purpose, either because they were not deemed toxic by the ECHA classification, labelling, and packaging standards, or, when diluted in a gas stream, presented negligible hazard to health or the environment. However, the report notes that all odorants must still be handled with care when they exist in their pure form, such as when injecting into a gas pipeline.

"Brittle-like cracking" is a type of plastic distribution line failure that could occur at points of high stress concentration, flawed pipe, or improperly installed fittings (Melaina, Antonia, and Penev 2013; Domptail et al. 2020). Metallic pipes used in U.S. distribution systems are typically made of low-strength steel and are not susceptible to brittle-like cracking (Melaina, Antonia, and Penev 2013). This cracking, however, would be difficult to detect until enough gas escapes and accumulates to activate gas sensor alarms for a given space. The largest reported safety incidents in the United States, as reported by the Office of Pipeline Safety, are caused by external factors such as third-party excavation (Pipeline Association for Public Awareness 2022).

3.2.4 Pressure Regulators

Pressure regulators placed throughout distribution systems reduce the pressure to meet operating requirements in the network downstream of the regulator and on to the end-user. Although regulators are common within distribution systems and at points of end-use, the literature on the effect of hydrogen blending on pressure regulators is limited. One study from the European Industrial Gases Association noted high-velocity flows associated with a blend may create problems in seals and plugs when the pressure drop through the regulator is greater than 10% of the upstream pressure (EIGA 2014). Another report from HyDelta described a project on testing pressure regulators with pure hydrogen at inlet pressures of 37.5 and 100 mbar (Kooiman 2022). This project determined regulator behavior deviation to be fractions of a millibar to that of natural gas service. The intervention sensitivity of the under-pressure shut-off valves placed after the regulator also increased by a few millibars when pure hydrogen was used. Haeseldonckx and D'haeseleer (2007) note that it may be advisable to install hydrogen injection points immediately downstream of pressure regulation stations for two reasons. First, the probability of backflow from the low-pressure grid to the high-pressure grid would be greatly reduced. Second, the lack of compressors in distribution networks further facilitates blending opportunities (Haeseldonckx and D'haeseleer 2007). Additionally, turbulence downstream of pressure reduction valves creates a region that facilitates gas mixing.

3.2.5 Meters and Valves

Positive displacement meters such as diaphragm and rotary meters are prevalent in distribution networks for domestic metering applications. These meters function by measuring the actual volume of gas displaced through them. Advantages of this method include accuracy and range of gas measurement. GRTgaz (2020a) conducted tests for both types of meters to ascertain the impact on measurement error of 10 and 20 vol % hydrogen blends. The study found that hydrogen presence induces a significant underestimation of flow rate for diaphragm meters as opposed to rotary meters, whose measurement error was minor in comparison. The magnitude of the effect is attributed to meter design because the tested diaphragm meters consist of polymeric materials, whereas the rotary meter utilize aluminum for measurement. Jaworski, Kułaga, and Blacharski (2020) investigated hydrogen blending effects on G4-sized diaphragm meters for hydrogen compositions up to 15 vol %, finding no significant impact on the accuracy or durability in the 5,000 hours of testing. This study was expanded to include 100 new and 10-year-service meters for continued durability testing up to 10,000 hours (Jaworski et al. 2021). The study detected no statistically significant influence attributed to servicing various hydrogen blend containing up to 15 vol %.

Hydrogen's smaller molecular structure may promote higher rates of leakage, particularly in valves placed along distribution lines or where flange connections, couplings, etc. occur. Huising and Krom (2020) found that natural gas valve stations were compatible with 100% hydrogen with no significant issues, even under higher-pressure test conditions of 960 psi. It remains unclear to them, however, what effects polymeric membranes used in other pressure control equipment may experience with higher concentrations of hydrogen. Furthermore, the impact of hydrogen on meter life is yet unknown; pipeline operators might need to conduct more frequent inspections to ensure adequate meter performance.

3.3 Underground Storage

Underground storage provides a significant means of providing reserve capacity for natural gas. As of 2013, 688 underground storage facilities were operating worldwide with a working gas capacity of 377 billion cubic meters (Judd and Pinchbeck 2016). The United States and Canada accounted for 40% of this capacity, with 414 and 59 storage sites, respectively. For natural gas networks that have underground storage facilities, injected hydrogen may eventually end up in those storage sites. The potential challenges associated with storing hydrogen underground are thus relevant to hydrogen blending projects. Key aspects to consider when evaluating a site for hydrogen injection include impacts on storage capacity, impacts on metal and concrete components at the well completion site, potential reactivity with minerals present in the subsurface, reactivity and subsequent loss of hydrogen due to the presence of microorganisms, and exploration and development costs for new storage sites.

There are four primary types of geological storage: salt caverns, hard rock caverns, depleted oil and gas reservoirs, and aquifers (Lord, Kobos, and Borns 2014; Shi, Jessen, and Tsotsis 2020). As of 2013, 74% of global geologic storage sites were in depleted oil and gas reservoirs, and 90% of storage sites in North America were porous reservoirs (including both depleted oil and gas reservoirs and aquifers) (Judd and Pinchbeck 2016). Each type of storage has advantages and disadvantages for storing hydrogen that have been well documented in literature focused on storing both pure hydrogen (Aftab et al. 2022; Thaysen et al. 2021; Panfilov 2016; Tarkowski 2019; Lord, Kobos, and Borns 2014; Papadias and Ahluwalia 2021; Zivar, Kumar, and Foroozesh 2021) and blends of hydrogen and natural gas (Judd and Pinchbeck 2016; Reitenbach et al. 2015; Shi, Jessen, and Tsotsis 2020). This section briefly summarizes these characteristics and the necessary precautions when considering using existing natural gas storage sites for storing hydrogen.

3.3.1 Hydrogen Storage Challenges Present for All Storage Types

For all storage types, the sealing ability of caprock must be confirmed (Zivar, Kumar, and Foroozesh 2021). According to Reitenbach et al. (2015), the addition of hydrogen may require additional efforts in this regard due to the high diffusivity of hydrogen, which could lead to hydrogen loss into the caprock. The lower volumetric energy density of hydrogen also means that adding hydrogen will reduce the total storage capacity, and the effects of hydrogen on underground storage wells must be considered and remedied. Specifically, the high diffusivity and low viscosity of hydrogen could lead to leakage through well equipment, and hydrogen embrittlement could impact metal components of the packer, tubing, and casing (Shi, Jessen, and Tsotsis 2020; Reitenbach et al. 2015). For these reasons, any materials used for production well completion must be specifically evaluated for compatibility with hydrogen. Tarkowski (2019) recommends a complete integrated evaluation of all processes involved in the conversion, including subsurface technical aspects of the boreholes and wells and above-surface equipment needed to store, handle, compress, separate, and deliver this blended mixture.

Hydrogen conversion and loss due to the presence of subsurface microorganisms is also possible in virtually all subsurface storage types (Aftab et al. 2022; Panfilov 2016), but it is most probable in depleted oil and gas reservoirs and aquifers (Judd and Pinchbeck 2016; Panfilov 2016). The presence of hydrogen in the subsurface may stimulate the growth of hydrogen-oxidizing bacteria and archaea, of which the most common types include hydrogenotrophic sulfate reducers that couple hydrogen oxidation to sulfate reduction to produce hydrogen sulfide (H_2S), hydrogenotrophic methanogens that reduce carbon dioxide (CO_2) to methane (CH_4) by oxidizing hydrogen, and homoacetogens that oxidize hydrogen and reduce CO_2 to produce acetate (Aftab et al. 2022; Thaysen et al. 2021; Zivar, Kumar, and Foroozesh 2021). The growth of these microorganisms in biofilms within the porous rock can reduce pore throat size and increase flow-path tortuosity, resulting in reduced permeability and reduced hydrogen storage capacity (Thaysen et al. 2021). In situ data on hydrogen behavior in the underground aquifer storage of town gas in Lobodice, Czech Republic, demonstrate that during 7 months of storage, methane content doubled while hydrogen, carbon dioxide, and carbon monoxide all significantly decreased (Panfilov 2016). Thaysen et al. (2021) reviewed reservoir conditions that influence subsurface microorganism development and hydrogen consumption, including temperature, salinity, pH, pressure, and presence of nutrients. They identify temperature and salinity as the most crucial environmental factors constraining the growth of homoacetogens, methanogens, and sulfate reducers. Considering storage conditions for 42 depleted oil and gas fields and 5 hydrogen storage test sites, they identify many sites that do not have temperature, pressure, and salinity conditions hospitable to microorganism growth. For the sites that do have ideal conditions for growth, they estimate hydrogen loss between 2%–4%, suggesting that the 17% hydrogen consumption by methanogens in Lobodice over 7 months may have been an exception. Thaysen et al. (2021) note that several knowledge gaps exist regarding prediction of microbial growth and experiments on subsurface life are needed to verify growth rate calculations, but emphasize that it is possible to select aquifers and depleted oil and gas fields that have extreme temperature and salinity conditions that are not hospitable to microorganism growth and for which hydrogen consumption and conversion may not pose substantial problems.

Both Thaysen et al. (2021) and Aftab et al. (2022) agree that any prospective storage sites should be carefully investigated and tested for microbial growth before development or injection of hydrogen. The influence of site selection and modification on operational costs should also be taken into account (Thaysen et al. 2021).

While microbial interactions are possible in the brine water within salt caverns' sump, the high salinity within salt caverns tends to prevent significant consumption and transformation of hydrogen, and as a result, salt caverns are considered one of the most inert types of underground storage (Aftab et al. 2022; Panfilov 2016). All underground storage types may contain water due to difficulties in achieving 100% brine recovery in salt caverns, formation water in residual oil within depleted oil and gas reservoirs, and the inherent water present in aquifers; some of this water may evaporate and mix with extracted hydrogen, adding cost to the gas dehydration process at the surface (Aftab et al. 2022).

3.3.2 Depleted Oil and Gas Reservoirs and Aquifers

As previously mentioned, porous reservoirs including depleted oil and gas reservoirs and aquifers constitute the majority of existing underground gas storage sites. Depleted oil and gas reservoirs have several advantages, including: (1) large storage volumes relative to other options; (2) well-defined geological characteristics, thanks to their previous exploration for extraction of oil and/or gas; and (3) proven capability of trapping gases given the fact that they stored oil and/or gas for millions of years (Lord, Kobos, and Borns 2014; Aftab et al. 2022; IEA 2019). The most significant challenges for hydrogen storage in depleted oil and gas reservoirs include the potential for residual hydrocarbons to affect hydrogen purity upon withdrawal (an issue that poses the biggest problem for pure hydrogen storage) and the potential for hydrogen to react with subsurface minerals in the presence of microorganisms (Aftab et al. 2022). The extent to which impurities associated with residual oil and gases is problematic will depend on the composition of the residual gases, the purity requirements of the end application, and the cost of achieving the necessary purity. For example, residual methane may not be problematic for combustion applications currently using stored natural gas that target less than 100% hydrogen, whereas applications that require 100% hydrogen, such as PEM fuel cells, will require additional purification if any non-hydrogen residual gases are present upon extraction.

While depleted oil and gas reservoirs are generally easy to develop and maintain due to the existing infrastructure (Lord, Kobos, and Borns 2014), aquifers tend to be more expensive to develop due to geologic uncertainty and the need for rigorous exploration activities to ensure the reservoir's sealing capabilities (Lord, Kobos, and Borns 2014; Aftab et al. 2022). Cushion gas requirements are also often higher for aquifers than depleted gas reservoirs because aquifers do not contain any residual gases that can offset the overall volume requirements; whereas depleted gas reservoirs may require 50% cushion gas, aquifers may require up to 80% (Lord, Kobos, and Borns 2014; Aftab et al. 2022). Hydrogen stored in aquifers could also potentially be lost by dissolving into the surrounding brine (Papadias and Ahluwalia 2021).

Oil and gas fields within the United States can be found in the Gulf Coast region (Texas and Louisiana), the central Plains and Mountain regions (Oklahoma, Kansas, Colorado, Wyoming, North Dakota, and Montana), and in the Midwestern region (Illinois, Indiana, Michigan, Ohio, Pennsylvania, West Virginia, and Kentucky). Aquifers can be found throughout most of the continental United States, with significant concentrations in the Gulf Coast and Southeast, Midwestern regions, and Western United States (Lord, Kobos, and Borns 2014).

3.3.3 Salt Caverns

Salt caverns are developed by solution mining large cavities into salt domes or within bedded salt deposits by injecting fresh water (Lord, Kobos, and Borns 2014). The salt surrounding these developed caverns is practically impermeable (Lord, Kobos, and Borns 2014; Aftab et al. 2022; Papadias and Ahluwalia 2021), and the high-salinity environment reduces the likelihood of hydrogen conversion by microorganisms (Aftab et al. 2022; Panfilov 2016). The result is that salt caverns are considered generally inert and tight (Aftab et al. 2022), so the most probable avenue for leakage or hydrogen loss is through the well head (Lord, Kobos, and Borns 2014). Salt caverns have very high storage efficiency (around 98%) and low risk of contamination due to the low presence of microorganisms and lack of remnant hydrocarbons found in depleted oil and gas reservoirs (IEA 2019). Hydrogen storage in salt caverns is a proven technology, with three facilities in Texas, one in the U.K., and two in Germany as of 2016 (Panfilov 2016). Salt caverns have been used by the chemical processing industry in the U.K. since the 1970s and the United States since the 1980s (IEA 2019; Papadias and Ahluwalia 2021) and are one of the lowest-cost forms of hydrogen storage, capable of achieving installed capital costs around $20/kg with sufficiently large caverns (Papadias and Ahluwalia 2021).

Key challenges for salt cavern storage include lower typical size and storage capacity than depleted oil and gas reservoirs (Aftab et al. 2022) and more limited geographic availability (Lord, Kobos, and Borns 2014; Papadias and Ahluwalia 2021); salt caverns within the United States are predominantly located in the Gulf Coast region (Texas, Louisiana, Mississippi, and Alabama), the central Plains region (Oklahoma, Kansas, Nebraska, North Dakota, and eastern Montana), and the Midwest and Northeast regions (Michigan, Ohio, Pennsylvania, West Virginia, and New York) (Lord, Kobos, and Borns 2014). The total capital cost of storage in these different locations can vary significantly with potential cavern size; for example, the Houston area can achieve much lower storage costs than the Detroit area (Lord, Kobos, and Borns 2014). Well-placed salt cavern storage sites can achieve high storage pressures (IEA 2019) and require a relatively low cushion gas volume of 33% (Lord, Kobos, and Borns 2014). Newly built salt cavern storage sites could be used for storing blends of hydrogen and natural gas or pure hydrogen and serve as a buffer to allow steady injection of hydrogen into natural gas pipelines.

3.3.4 Lined Rock Caverns

Recent technology has been investigated for excavating hard rock caverns and encasing those excavated caverns entirely with steel or plastic liners, which act as an impervious layer (Lord, Kobos, and Borns 2014). While this type of geologic storage has not been used to date for storing hydrogen at an industrial scale, pilot projects have demonstrated its viability for natural gas storage (Papadias and Ahluwalia 2021). Advantages of this technology include high operating pressure (Papadias and Ahluwalia 2021) and low cushion gas requirements. Hard rock outcrops are present in the Western and Northwestern United States (California, Colorado, Washington, and Idaho), Minnesota, and the Atlantic Coast region (Lord, Kobos, and Borns 2014). Lined rock caverns are slightly more expensive to develop than salt caverns, achieving installed hydrogen storage capital costs around $50/kg with similar storage capacities around 2,000–3,000 tonnes. Like salt cavern storage, lined rock caverns could store both hydrogen and natural gas or solely pure hydrogen.

3.4 End-Use Appliances

Blending challenges in end-use appliances are numerous and varied, as there are many combustion scenarios under which a hydrogen blend could be used, and each case will need to be studied to understand the unique challenges to ensure a suitable product is delivered to the end-user. Such factors to be considered include but are not limited to Wobbe Index, gas mixture calorific value, minimum oxygen and air requirements, flashback, flame speed, power output, combustion controls, and emissions. The impact of these factors are described in Section 6.2, which details findings from end-use appliance demonstrations using hydrogen blends.

3.5 Hydrogen Separation

While many current natural gas end-use applications may be adapted to operate with a mix of hydrogen and natural gas, some applications may require pure hydrogen (such as PEM fuel cells for transportation) or very low quantities of hydrogen. In either scenario, hydrogen would need to be separated from natural gas at or near the point of end-use. The primary types of hydrogen separation technologies include pressure swing adsorption (PSA), cryogenic distillation, membranes, and electrochemical hydrogen separation (Melaina, Antonia, and Penev 2013; National Grid 2020; Hu et al. 2020; Vermaak, Neomagus, and Bessarabov 2021). Each of these technologies has advantages, disadvantages, and scenarios in which they perform best. Several previous literature studies have summarized hydrogen separation technologies in detail (Melaina, Antonia, and Penev 2013; National Grid 2020; Lu et al. 2021; Hu et al. 2020; Vermaak, Neomagus, and Bessarabov 2021); this section briefly summarizes the key findings of these studies.

3.5.1 Pressure Swing Adsorption

PSA is a commercially mature technology used to purify hydrogen produced from SMR (Melaina, Antonia, and Penev 2013), currently accounting for about 85% of hydrogen separation (Vermaak, Neomagus, and Bessarabov 2021). PSA systems consist of multiple packed beds of highly porous materials that are carefully selected such that non-hydrogen species such as CO, CO_2, and CH_4 adsorb onto the material at high pressure, while the hydrogen passes through (Melaina, Antonia, and Penev 2013). The packed beds are then depressurized, which allows the surface species to return to the gas phase and exit the PSA system. To maintain quasi-continuous flow, these systems require multiple packed beds with valves that control the allocation of flow into beds that are adsorbing non-hydrogen species and out of beds that are regenerating; generally, at least eight packed beds are necessary (Vermaak, Neomagus, and Bessarabov 2021). Because pressure is the driving force for separation in PSA, these systems operate best near transmission pipeline pressures to avoid bulk gas compression; for typical SMR systems, PSA columns employ the natural gas pipeline pressure for gas adsorption and the SMR burner pressure for bed regeneration (Melaina, Antonia, and Penev 2013). PSA systems can yield high-purity hydrogen around 98%–99.999%, with hydrogen recovery rates between 60% and 90% (National Grid 2020). A trade-off exists between purity and hydrogen recovery rate; reducing the adsorption-regeneration cycle time from a typical period of around 10 minutes to a much shorter time of around 30 seconds (considered "rapid" PSA) can increase hydrogen purity, but at the expense of hydrogen recovery rate (Melaina, Antonia, and Penev 2013; National Grid 2020).

Advantages of PSA include its capability of achieving high hydrogen purity and decent hydrogen recovery rates, delivery of pure hydrogen at high pressure, lack of need for process heating or cooling, technological maturity, and capability to scale to system capacities up to 10 million Sm^3/day (or approximately 898 tons/day) (Melaina, Antonia, and Penev 2013; National Grid 2020; Hu et al. 2020; Vermaak, Neomagus, and Bessarabov 2021). Disadvantages include the fact that PSA produces non-hydrogen residue gases at relatively low pressures compared to natural gas transmission lines, meaning that PSA systems require either recompression of these gases back up to transmission pipeline pressure (Hu et al. 2020) or delivery to low-pressure fuel users downstream of the PSA system (Melaina, Antonia, and Penev 2013; National Grid 2020). PSA is also not generally used for purifying feed gases with less than 50 vol % hydrogen (Melaina, Antonia, and Penev 2013; National Grid 2020) because doing so would require adsorbing and desorbing the bulk of natural gas down to near-atmospheric pressure. Furthermore, Hu et al. (2020) point out that using PSA for low-hydrogen-concentration mixes would require larger facilities and more frequent cycles, thus increasing overall costs. It can thus be concluded that PSA systems are most appropriate for mixtures of hydrogen and natural gas with a fairly high concentration of hydrogen ($>$50% by volume) operating at a fairly large scale and positioned at a pressure reduction station to avoid non-hydrogen gas recompression.

3.5.2 Membrane Separation

A membrane is a selective barrier that allows mass transfer under a driving force such as a gradient in pressure, temperature, concentration, or electrical potential (Vermaak, Neomagus, and Bessarabov 2021). Hydrogen transport across membranes may follow one or a combination of mechanisms including viscous flow, Knudsen diffusion, molecular sieving, solution diffusion, and surface diffusion (Hu et al. 2020). Membrane performance for common porous hydrogen-methane membranes can be characterized by the permeability of hydrogen (which is a function of the gas flux through the membrane, membrane thickness, and difference in partial pressure of hydrogen between the feed and permeate streams) and the selectivity of hydrogen versus methane (which is the ratio of permeability of hydrogen to the permeability of methane for the membrane) (Hu et al. 2020). Because the difference in partial pressure of hydrogen between the feed and permeate sides of the membrane drives separation, high feed pressure (at least 20 barg) is necessary to achieve efficient hydrogen separation (National Grid 2020). As with PSA systems, transmission lines can provide the necessary pressure. Unlike PSA systems, however, membranes produce hydrogen at pressures much lower than that of the pipeline; whether or not this necessitates recompression depends on the system design and pressure requirements of downstream applications.

In general, membrane technology is mature and widely used in industry (Melaina, Antonia, and Penev 2013; Hu et al. 2020; Vermaak, Neomagus, and Bessarabov 2021), though some types of membranes are more novel than others. Polymeric membranes are the most mature type (Lu et al. 2021) and constitute the majority of industrial processes due to their ability to handle high pressure drops, low cost, and scalability (Vermaak, Neomagus, and Bessarabov 2021). Conventional membranes consist of polymeric hollow fibers such as polysulfone, aromatic polyamides, cellulose acetate, and polydimethylsiloxane; can be rubbery or glassy polymers; and are supplied as modules (National Grid 2020). A major limitation for polymeric membranes is their trade-off between gas permeability and selectivity, known as Robeson's upper bound (Hu et al. 2020; Lu et al. 2021). This trade-off means that attempts to increase recovery via increasing membrane surface area or feed pressure will reduce membrane selectivity, resulting in a reduction in product hydrogen purity; one way to deal with this is to recycle a portion of the purified hydrogen in a two-stage membrane process (National Grid 2020). Maximum hydrogen purity achievable with polymeric membranes is around 98% with feed gas hydrogen concentration around 50% by volume, while 50%–70% purity is possible with feed gas hydrogen concentration around 5%–10% (National Grid 2020). Polymeric membranes are suitable for capacities up to 2 million Sm^3/day (180 tons/day), with economic flexibility at smaller scales due to the modularity of units (National Grid 2020).

Dense metallic membranes made with palladium (Pd) receive a significant amount of attention because at high temperatures, hydrogen dissociates upon contact with palladium and the resulting protons dissolve into the metal (Melaina, Antonia, and Penev 2013; Lu et al. 2021). As a result, Pd membranes can achieve hydrogen purity up to 99.9999999% (Melaina, Antonia, and Penev 2013; Hu et al. 2020; Lu et al. 2021). These membranes are particularly attractive for applications that require ultra-high purity, such as PEM fuel cells (National Grid 2020). Pd membranes pose a number of challenges, however. They are significantly more expensive (Lu et al. 2021), costing roughly 20 times that of polymeric membranes on a unit surface area basis (National Grid 2020). They are also very sensitive to a variety of surface contaminants including hydrogen sulfide, carbon monoxide, thiophene, chlorine, and iodine (Vermaak, Neomagus, and Bessarabov 2021). Pd membranes require relatively high temperature above 300°C to operate (Melaina, Antonia, and Penev 2013; Hu et al. 2020; Lu et al. 2021), which would require significant heating beyond typical natural gas pipeline temperatures. Melaina, Antonia, and Penev (2013) point out that a 10% hydrogen feed in an ideal scenario would require 33 atm of driving pressure to produce hydrogen at ambient pressure with 70% recovery, making dilute mixtures a challenge for Pd membranes. Pd membranes also have relatively low mechanical strength and must be alloyed with another metal to accommodate the high pressure difference necessary to achieve sufficient flux (Melaina, Antonia, and Penev 2013; Lu et al. 2021); however, alloying with copper can improve tolerance toward sulphur impurities (Melaina, Antonia, and Penev 2013; National Grid 2020), and alloying with cheaper metals can reduce the overall membrane cost (National Grid 2020).

3.5.3 Cryogenic Separation

Cryogenic separation utilizes the extremely low boiling point of hydrogen (20.1 K) to condense non-hydrogen species such as methane out of the mixture, leaving hydrogen in the vapor phase. Cryogenic hydrogen separation is a mature, commercial technology capable of producing high-purity hydrogen (98%–99%) at high pressure with recovery rates typically between 80%–90% and up to 95% (National Grid 2020; Hu et al. 2020). It should be noted that feed gas pretreatment is required to remove species that may freeze such as carbon dioxide, hydrogen sulfide, and water (National Grid 2020); water should be reduced to <1 ppm and carbon dioxide should be reduced to <100 ppm (Vermaak, Neomagus, and Bessarabov 2021). Any significant amounts of carbon monoxide and nitrogen gas present should also be reduced via a methane wash column (Vermaak, Neomagus, and Bessarabov 2021). Cryogenic separation is cost-effective at large scales but unsuitable for small-scale applications (National Grid 2020; Vermaak, Neomagus, and Bessarabov 2021; Hu et al. 2020). Cryogenic plants may also require higher startup and shutdown times than other technologies due to their very low operating temperatures (National Grid 2020), and the extensive cooling required results in significant energy consumption (Vermaak, Neomagus, and Bessarabov 2021).

3.5.4 Electrochemical Hydrogen Separation

Electrochemical hydrogen separation (EHS) is a technology in which an electrochemical potential drives hydrogen molecules to dissociate into H^+ ions on a proton-conduction anode, transport through a proton-conducting membrane, and then reassociate into molecular hydrogen at a cathode (Hu et al. 2020). The primary advantage of this technology is that it can produce hydrogen at very high purity up to 99.999% by volume in a single step (National Grid 2020; Hu et al. 2020; Vermaak, Neomagus, and Bessarabov 2021). The two most common materials used as membranes for EHS are Nafion and polybenzimidazole (PBI) (Melaina, Antonia, and Penev 2013; National Grid 2020). Vermaak, Neomagus, and Bessarabov (2021) provide a detailed summary of published articles on EHS. The hydrogen separation rate of EHS is controlled by the applied current (Vermaak, Neomagus, and Bessarabov 2021), and EHS can work well with low hydrogen concentrations around 10% by volume (National Grid 2020). EHS can also be used as an electrochemical compressor to boost hydrogen pressure from around 3–15 barg to up to 875 barg and can be quite modular due to its development in individual stack units (National Grid 2020; Vermaak, Neomagus, and Bessarabov 2021). EHS has several drawbacks, however. It is limited to 70%–80% recovery rate; it requires water for humidification of the system, which thus requires downstream dehydration; polybenzimidazole membranes can produce highly corrosive phosphoric oxide vapours; and EHS technology is relatively immature compared to other technologies discussed in this review (Melaina, Antonia, and Penev 2013; National Grid 2020). Another concern for EHS systems used to separate hydrogen from natural gas is that double-bonded hydrocarbons such as ethylene and propylene, which are commonly present in small concentrations in natural gas, can readily polymerize on many process surfaces and create impermeable coatings that reduce device performance.

3.5.5 Economics of Hydrogen Separation from Blended Natural Gas

Relatively few existing publications cover the economics of hydrogen separation from blended natural gas; however, National Grid published a study in 2020 evaluating the economics of implementing hydrogen separation technologies against a number of case studies based on actual network operating conditions within the Great Britain gas network (National Grid 2020). This study considered realistic and representative gas network operating conditions and evaluated feasibility considering the range of inlet and outlet pressures seen in the network. National Grid considered cryogenic separation and a hybrid system consisting of membrane separation and PSA operated in series, with the objective of achieving combustion-grade hydrogen with hydrogen content greater than 98% by volume and concentration of CO_2 and hydrocarbons less than 1% by volume. The study also confirmed that hydrogen separation could be used to provide natural gas with low hydrogen concentration to customers with high sensitivity to hydrogen.

They considered two distribution network scenarios (one with 2-barg outlet pressure and the other with 20-barg outlet pressure, both with 30-barg inlet pressure) and two transmission network scenarios (one with 7-barg outlet pressure and one with 30-barg outlet pressure, both with 60-barg inlet pressure). For each scenario, they considered separation of blend ratios of 5%, 10%, 20%, and 40%. They identified minimum specific cost of hydrogen recovery for 20% by volume feed blends in the range of £1.0–£1.6/kg for the membrane-PSA system and £0.9–£1.4/kg for the cryogenic process when minimum compression costs are accrued because the downstream natural gas systems operate at low pressure. They found that in scenarios that require recompression of residue gas for reinjection into gas networks operating at elevated pressure, process optimization can limit the increase in specific cost of hydrogen recovery to an incremental 20%–50%. The worst case, which requires recompression to pipeline feed pressure, sees hydrogen recovery cost increases of 50%–80% relative to scenarios with minimal compression requirements. The study found that costs are generally lower for transmission networks than for distribution networks, and that cost is highly sensitive to hydrogen content in the feed gas, with lower hydrogen concentration resulting in higher costs. In general, recovery of hydrogen at concentrations below 20% by volume is likely to be uneconomic (National Grid 2020). The study found that the difference in cost between cryogenic and membrane + PSA technologies is relatively minor in most scenarios, though cryogenic separation achieves slightly lower costs for hydrogen recovery in distribution networks with 5% and 10% hydrogen concentration. Considering that separation from 5% and 10% blends is already likely to be uneconomic, National Grid concluded that process selection is yet inconclusive and may depend on other technical and nontechnical factors such as ease of startup, dynamic capability, environmental constraints, and spatial constraints.

4 Network Design and Operation

Significant difficulties in both prediction and management of pipeline operations arise from interactions between different pipeline equipment as the transported gas composition changes. Both distributed and centralized injection of hydrogen influences network pressures, flow rates, and the compression power required to transport natural gas mixtures. Understanding the operating states of a gas network with varying gas composition requires an adequate gas network model. The tolerance of natural gas pipeline systems to the introduction of hydrogen must be considered on a case-by-case basis while accounting for network structure, gas composition, flow rates, existing facilities, and end-use constraints. Previous studies have developed several approaches to analyze pipeline systems to include the presence of hydrogen in natural gas admixtures. This section summarizes the available research on evaluating the design and operation impacts of hydrogen blending.

Prior to 2000, few publications existed focusing on the effects of hydrogen on natural gas pipeline system operations. Recent literature, however, has taken the approach of analyzing gas composition, flow rates, and pressure profiles within pipeline networks when considering hydrogen injection and then comparing network flow rates and pressures to those of a reference natural gas mixture. Note that natural gas is a combination of gases (with methane being the primary component), and the natural gas composition may vary significantly depending on the source and location of the gas in the network. This composition variability could be observed in how the natural gas heat content varies nationally, as heat content is dependent on gas composition (U.S. Energy Information Administration 2021). Therefore, gas composition is an important consideration when evaluating network operations with injection of unconventional gases such as hydrogen. Table 6 provides a summary of studies analyzing gas network operations with hydrogen injection. The results from these studies show that natural gas pipeline system operation is highly influenced by the gas composition and the network structure.

4.1 Steady-State Modeling

Several studies approach gas network operation analysis using steady-state modeling via simulation or optimization. van der Hoeven (1998) conducted gas quality analysis when including hydrogen blending in a steady-state pipeline gas flow model simulating energy flow rates within a network. They modified their model for estimating pressure drop to reflect gas demand in energy flow rate rather than standard volumetric flow rate. Tabkhi et al. (2008) propose a steady-state optimization model utilizing a simplified branched network topology to investigate the impacts of hydrogen injection on pipeline energy transmission rates and compression operation. They found that replacing natural gas with hydrogen entirely would result in a maximum achievable pipeline transmittable power 16% of that of a pure natural gas pipeline. Alternatively, maintaining constant transmitted power limits the hydrogen blend to 6.6% on a mass basis when constraining pipeline end-point pressure. Hernández-Rodríguez et al. (2011) expand upon the optimization model proposed in Tabkhi et al. (2008) to include compressor performance curves and multiple objective functions. B. Wang et al. (2018) develop an optimization model to retrofit an existing transmission pipeline for hydrogen injection. This model includes gas network modification options such as pipeline substitution to meet constraints derived from ASME B31.12-2004, new compressor station construction, and modifying existing compression station operation to accommodate hydrogen admixtures.

Osiadacz (1987) and Osiadacz (1988) discuss the simulation of steady-state gas networks, which provides another alternative for hydrogen blending analysis. Abeysekera et al. (2016) adapt the methods of Osiadacz (1987) and Osiadacz (1988) to analyze the effects of distributed hydrogen injection in the low-pressure distribution networks considering injection of hydrogen or upgraded biogas. They find that injecting hydrogen with the same volumetric flow rate results in an increase in steady-state nodal pressure due to the lower specific gravity of a high-hydrogen-gas mix, but a reduction in the calorific value of the stream due to hydrogen's lower volumetric energy density. When increasing flow rate to achieve an equivalent energy transmission rate as a pure natural gas line, their model predicts an increase in pressure drop and therefore a reduction in pressure throughout the network. Adolfo and Carcasci (2019) also investigate the location impact of hydrogen injection within low-pressure gas networks. Pellegrino, Lanzini, and Leone (2017) utilize and extend the discussed simulation methods to analyze the effects of alternative gas injection into a transmission pipeline network under steady-state and non-isothermal conditions. Cheli et al. (2021) develop a steady-state model of a natural gas distribution network in Tuscany, Italy, to investigate how hydrogen injection would influence gas properties when taking into account local renewable profiles and gas demand. They note that hydrogen injection impacts the Wobbe Index of the fuel and investigate how injection placement and injection control algorithms could be used to mitigate this effect.

Other studies utilizing steady-state modeling focus on specific phenomena associated with hydrogen blending and/or sections of the natural gas pipeline containing specific equipment. Kurz, Lubomirsky, and Bainier (2020) simulate the effects of different hydrogen levels in a pipeline system to analyze effects of hydrogen on natural gas turbine combustion, safety, and pipeline transportation efficiency. They also investigate the amount of carbon dioxide produced by gas turbines fueled by a blend of natural gas and hydrogen. Abd et al. (2021) investigate the impact of hydrogen blending on natural gas mixture thermodynamic properties and extend the analysis to consider hydrogen admixture effects on transmission pipelines associated with changes in pressure drop and heat transfer within steady-state modeling.

4.2 Transient and Non-Isothermal Modeling

Although several papers propose steady-state models of the gas system, the steady-state assumption is insufficient for assessing dynamic natural gas pipeline operations, as gas pipeline properties change with time. Transient models are more useful for accurately modeling pipeline dynamics and line pack. Guandalini, Colbertaldo, and Campanari (2017) investigate the effect of hydrogen gas injection and gas off-take profiles on transmission pipeline operations under dynamic pipeline conditions. They validate a transmission pipe case study against pipeline operations data and extrapolate to consider hydrogen blending effects. The extrapolated case study provides density, heating, and pressure profiles with respect to pipeline location, time, and hydrogen content. Isothermal conditions is another commonly observed assumption in prior literature that could create significant inaccuracies if used in detailed thermophysical modeling. Potential outcomes of improperly assuming isothermal conditions include line pack overestimation and compression duty underestimation. Uilhoorn (2009) presents a case study for Poland's Yamal–European natural gas pipeline to illustrate modeled hydrogen blending effects on non-isothermal transient flows, and recommends avoiding the isothermal assumption when high modeling precision is required. This study shows that under a constant volume demand scenario, hydrogen blending reduces transmission pipeline pressure drop, temperature gradients, and compressor duty. Uilhoorn (2009) demonstrates that for constant gas volume demand scenarios, hydrogen blending reduces pressure oscillation amplitude along the pipeline during short periods of transient flow. Conversely, hydrogen blending increases pressure oscillation amplitude in constant energy demand scenarios. Osiadacz and Chaczykowski (2020) discuss generalized gas network models for different spatial and temporal resolutions and provide similar guidance regarding the isothermal assumption.

Table 6. Publications Focused on Network Design and Operation

Reference	Application	Included Non-Pipe Elements	Max. H_2 Blend Level Considered	System Dynamics	Non-Isothermal Equations
Tabkhi et al. 2008	100-km didactic transmission network	Compressors	6%	Steady-state	-
Uilhoorn 2009	177-km transmission network in Western Europe	Compressors	65%	Transient	Yes
Hernández-Rodríguez et al. 2011	100-km transmission test network	Compressors	6.6%	Steady-state	-
Abeysekera, Rees, and Wu 2014	Decentralized injection on a test distribution network	-	20% + 400 kJ/s	Steady-state	-
Elaoud, Hafsi, and Hadj-Taieb 2017	Looped transmission network	Valves	100%	Transient	-
Pellegrino, Lanzini, and Leone 2017	Regional-scale transmission system with looped branches	Compressors, regulation stations	10%	Steady-state	Yes
Guandalini, Colbertaldo, and Campanari 2017	Linear transmission pipeline in central Italy	Gas metering	5%	Transient	-
Agaie et al. 2018	One pipeline	Valves	100%	Transient	Yes
Andresen, Bode, and Schmitz 2018	Coupled transmission network in Hamburg	Compressors, storage, trailers, electrolyzer	6,323.16 tons	Transient	-
B. Wang et al. 2018	Transmission pipeline with two branches	Compressors	10%	Steady-state	-
Adolfo and Carcasci 2019	Distribution network with three sources	-	5%	Steady-state	-
Liu et al. 2019	TransCanada Pipeline Gas Dynamic Test Facility	Pressure sensors, pressure transducers	6%	Steady-state	-
Ekhtiari, Flynn, and Syron 2020	Simplified Irish transmission network	Compressors, wind generators	15%	Transient	-
Kurz, Lubomirsky, and Bainier 2020	768-km transmission pipeline	Compressors	20%	Steady-state	-
Osiadacz and Chaczykowski 2020	Distribution network in Poland	Power-to-gas plant	10%	Transient	Yes
Abd et al. 2021	94-km transmission network from the Transitgas project	-	10%	Steady-state	-
Cavana and Leone 2021	Greenstream gas corridor transmission network	Compressors, power-to-gas	20%	Transient	-
Clees et al. 2021	Transmission network of Western Germany	Compressors	100%	Transient	Yes

Major hydrogen blending effects on networks are also modeled to anticipate short-duration operational consequences that may lead to compromised pipeline integrity. For example, the presence of hydrogen exacerbates hydraulic shock, which is a phenomenon resulting from rapid valve closure that occurs in seconds. Elaoud, Hafsi, and Hadj-Taieb (2017) studies this effect numerically in high-pressure pipeline networks by developing a two-staged approach considering steady and transient states. They determine initial pipeline network conditions for the transient analysis using a combination of pipe flow models, Kirchhoff's second law, and simulation using the Hardy Cross method and utilize the characteristics approach of defined time intervals to solve the conservation equations for one-dimensional isentropic compressible flow and to simulate the transient pressure response in a gas network for gas mixtures with variable hydrogen composition when emergency and automatic control valves actuate to closure. The results indicate that the pressure waves generated in hydrogen admixtures from rapid valve closure could exceed the allowable stress of different grade pipeline steels for short periods of time in networks designed for natural gas. Agaie et al. (2018) present a similar scenario to Elaoud, Hafsi, and Hadj-Taieb (2017), but considering non-isothermal conditions. This study uses reduced-order modeling to evaluate the effect of mass ratios, pipe inclination, and heat transfer between the pipe fluid and the environment. Their results indicate that the pipeline temperature significantly influences transient results of the simulation and that elevated hydrogen content increases the magnitude of pressure variations and celerity waves in response to rapid valve closure.

4.3 Studies on Hydrogen From Renewables for Blending

Many studies have analyzed operating strategies for utilizing variable renewable energy production to produce hydrogen for blending into natural gas pipeline networks. Andresen, Bode, and Schmitz (2018) compare hydrogen production cost, overall efficiency, and carbon dioxide emissions for hydrogen generated from excess renewable power and delivered via three alternative transport methods. Ekhtiari, Flynn, and Syron (2020) model a gas network to determine operating strategies to meet the required network end-user energy demand with fluctuating gas quality attributed to variable renewable energy. They find that for the case study investigated, electrolyzers could fully utilize curtailed wind energy for hydrogen injection into a simplified national gas network on a given windy day, and that hydrogen injection into this gas pipeline network would not have a significant impact on network pressure drop, flow rate, or ability to deliver sufficient energy. The study does find, however, that hydrogen injection has a significant impact on gas quality, which varied significantly across the network during the modeled time period. Cavana and Leone (2021) model the Green Stream gas corridor (transmission pipeline spanning from Libya to Italy) using a transient multicomponent transport model and consider several hydrogen blending scenarios utilizing solar photovoltaic technology to power electrolyzers. This study compares the compressors' duty and operating hours to transport an equivalent quantity of energy between a baseline natural gas pipeline transport scenario and a set of hydrogen blending scenarios with different hydrogen compositions. Consistent with other reviewed studies, they find that the compression duty increases severalfold; however, the authors note that this energy requirement is insignificant relative to the transmission pipeline throughput. Cavana and Leone (2021) also explore the role of energy storage for maintaining constant hydrogen blending levels despite a mismatch between photovoltaic electricity production and gas demand. The study implements an iterative optimization procedure to minimize storage volume to provide constant blending service over an 11-day time frame. The authors note the importance of renewable energy storage to resolve the dynamic supply and demand mismatches. Clees et al. (2021) conduct a high-fidelity analysis of a transmission gas network considering two equations of state and a range of gas compositions that includes biogas, syngas, and hydrogen admixtures. They also present an approach for adjusting compressor characteristic maps and an iterative method for solving transient non-isothermal Euler equations with efficient integration of the GERG-2008 equation of state. This approach is demonstrated on a German transmission pipeline network to simulate dynamic gas composition profiles in several pipeline locations considering variable renewable hydrogen injection.

5 Techno-Economic Studies of Hydrogen Blending in Natural Gas Pipelines

A number of studies have attempted to quantify the economics of blending hydrogen into natural gas pipeline infrastructure. These studies range significantly in scope and objective, and the features that may or may not be present include: (1) physical modeling of the natural gas pipe network, (2) physical modeling of the electricity grid, (3) techno-economic modeling of hydrogen production technologies such as electrolysis, and (4) techno-economic modeling of upgrades necessary to operate the natural gas pipeline network with some quantity of hydrogen. These publications can broadly be cast into two categories: studies that focus on the economics of using hydrogen blending to improve renewables integration and reduce emissions, and studies that attempt to capture the costs of upgrading natural gas pipelines to be compatible with some quantity of hydrogen.

5.1 Economics of Hydrogen Blending for Renewables Integration

Many studies focus primarily on using the natural gas grid as a sink for variable renewable energy sources and attempt to quantify the amount of hydrogen that can be blended given demand, available renewable resources, and blend limit while often assuming that little to no modifications will be necessary to accommodate low blend ratios. For example, Qadrdan, Abeysekera, et al. (2015) investigate the value of adding electrolyzers for different allowable levels of hydrogen injection into the UK gas network. They perform operational optimization of a combined model of Great Britain's gas and electricity networks to determine the minimum cost of meeting electricity and gas demand for typical low and high electricity demand days in the presence of significant wind generation. They consider three blending scenarios: one without hydrogen, one with hydrogen injection limited to 5% by volume, and one with unlimited hydrogen blending that did not quantify potential costs of pipeline upgrades in their modeling. They find that for the low electricity demand cases, the 5% blending limit scenario achieves a 1% reduction in operating costs and a 0.7% reduction in emissions, while the unlimited blending scenario achieves a 7% reduction in operating costs and a 2% reduction in emissions. For the high electricity demand cases, the 5% blending limit scenario achieves a 9% reduction in operating costs but a 0.2% increase in emissions, while the unlimited blending scenario achieves an 11% reduction in operating costs and a 0.7% reduction in emissions. The modest reduction (and in one case increase) in emissions is due to higher dispatch of carbon-intense coal to meet electricity demand. It should be noted that the maximum hydrogen penetration is only 3% by energy in the unlimited blending, low electricity demand scenario. In a subsequent publication, Qadrdan et al. (2017) improve the combined gas and electric network model to adopt a rolling planning approach, taking into account unit commitment constraints and comparing the performance of flexible gas plants, electricity storage, and power-to-gas as means of providing grid flexibility. With the objective of minimizing the total operating costs of both gas and electric networks, they find that all flexibility approaches increase contribution from wind and non-dispatchable coal with carbon capture and sequestration; electrical energy storage boosts the total change in electrical production the most, but power-to-gas increases the wind penetration the most. Regarding operating costs, this study finds that electrical energy storage reduces costs the most, by approximately 1.5% in winter and 0.9% in summer; power-to-gas, on the other hand, reduces costs by 0.3% in the winter and 0.2% in the summer.

Timmerberg and Kaltschmitt (2019) investigate the costs for producing hydrogen in North Africa and using existing pipelines operating between Algeria and Spain, Algeria and Italy, and Libya and Italy to transport hydrogen to central Europe with hydrogen blends of up to 10% by volume. This study primarily focuses on the optimization of sizing of wind, solar, and electrolysis facilities and quantification of hydrogen production potential, levelized cost of hydrogen, and the hydrogen quantities that could be transported within the existing pipelines. Timmerberg and Kaltschmitt (2019) quantifies the impact of hydrogen blending on compressor operating costs, demonstrating that transport costs for hydrogen are 2.6–3.6 times higher than for natural gas in the scenarios considered. They do not, however, consider any other potential costs associated with blending hydrogen into existing natural gas transmission lines such as replacement of pipes or other components. Pellegrini, Guzzini, and Saccani (2020) perform an analysis with the intent of quantifying the amount of green hydrogen that could be produced and injected into the Italian natural gas grid without compromising its integrity or causing problems for end-users. They define an approach to estimate the maximum blending threshold (in Sm^3/h) as a function of the allowed blending percentage (defined as the upper limit of hydrogen blending under which modifications to the network and its auxiliaries are unnecessary), hydrogen density, natural gas density, minimum natural gas flow rate, and a safety factor. Clegg and Mancarella (2016) employ an integrated gas and electrical network model with hydrogen injection and seasonal energy storage to assess the potential benefits of such a system and quantify the ability of Great Britain's gas network to accommodate power-to-gas. Their two-stage modeling approach assesses gas generation, power-to-gas utilization, daily gas storage, and gas network operation at half-hour time increments to (1) identify the optimal power flow for the grid, and (2) maximize the system benefit of power-to-gas. They consider two renewable penetration scenarios, both 3% and 17% by volume hydrogen blending limits, and evaluate how the power-to-gas process impacts natural gas prices, finding that in the "Gone Green" scenario, power-to-gas can lead to an additional integration of 35.6 TWe/yr of renewable generation and a 4% reduction in the annual cost of natural gas. They also identify that increasing the hydrogen content in the network can reduce the flow capacity at network extremities due to an increase in pressure drops by up to 7% for a hydrogen content limit of 17% by volume.

5.2 Economics of Natural Gas Pipeline Upgrades

Many economic studies of hydrogen blending assume a fixed maximum blend ratio, typically lying between 5% and 20% by volume (Pellegrini, Guzzini, and Saccani 2020; Cheli et al. 2021; Qadrdan, Chaudry, et al. 2015; Dodds and Demoullin 2013; Guandalini and Campanari 2015). Others assume that hydrogen cannot be injected into transmission pipes altogether due to the high pressure of transmission lines (Ma and Spataru 2015) or due to their steel construction (Dodds and McDowall 2013). Many publications agree, however, that the actual limit will be case-dependent (GRTgaz et al. 2019; B. Wang et al. 2018; Abeysekera et al. 2016; Timmerberg and Kaltschmitt 2019). The maximum blend ratio for an entire pipeline network will likely be set by the network component for which the maximum blend ratio is lowest. Pipeline networks consist of a number of components, including transmission pipelines, compression stations, pressure reduction stations, storage tanks and manifold piping, valves, fittings, and meter stations (Menon 2015). The tolerance of these components to hydrogen will depend on their materials of construction and design. A limited number of publications have attempted to assess how materials and design of pipeline components could impact their compatibility with hydrogen.

Cerniauskas et al. (2020) investigate the potential costs of reassigning pipelines in the German pipeline network to operate with 100% hydrogen with an emphasis on transmission pipelines. They consider reassignment options including the admixture of inhibitors to prevent adsorption of hydrogen by the pipeline material, coating of pipelines, implementing new pipelines within the existing pipelines, and using the pipelines without substantial modifications but increased maintenance to manage material degradation. Inhibitors considered include O_2, SO_2, and CO, which require concentrations of 0.015%, 2%, and 2%, respectively. The authors note that while inhibitors would require only limited modifications to the pipeline, drawbacks include toxicity and security risks along with the potential need for an additional purification step at the point of end-use. They compare these options with gaseous and liquid hydrogen trailers and newly built hydrogen pipelines. They assess the coatings and pipeline-in-pipeline options only qualitatively, speculating that these methods would require pipeline excavation and therefore be prohibitively expensive. For both reassignment without modification and reassignment with inhibitors, they assume that compressor stations and gas pressure regulation equipment would need to be completely replaced, though the reassignment with inhibitors option also requires the operating expense of the inhibitor and both capital and operating expenses for purification of the hydrogen at the point of end-use. They find that for large-diameter pipes, reassignment without modification is 60% less expensive than building new hydrogen pipelines, while reassignment with inhibitors is actually more cost-intensive than construction of new hydrogen pipelines. They find that using inhibitors for small pipelines, however, results in similar cost reductions compared to pipeline reassignment without modification because the cost to implement inhibitors in small pipelines is less governed by fixed operating costs. When considering countrywide effects of the two methods, the authors find that pipeline reassignment could reduce costs by 20%–60% compared to building new hydrogen pipelines; however, O_2 inhibitor reassignment remains consistently more expensive than the alternative of pipelines without substantial modifications due to higher sensitivity to low pipeline utilization. It should be noted that Cerniauskas et al. (2020) claim that pipes constructed of X70 can be suitable for operation with hydrogen because of the low susceptibility to hydrogen-induced subcritical crack growth at heat-affected zones and because fatigue crack propagation can be mitigated; however, other studies have found susceptibility of X70 to hydrogen embrittlement and cracking for both the weld (Nguyen et al. 2020) and the parent material (Chandra et al. 2021).

B. Wang et al. (2018) note that the problems caused by mixing hydrogen into natural gas pipelines should be evaluated using guidelines for the design of pure hydrogen pipelines. They employ ASME B31.12-2014 to assess the suitability of natural gas pipelines for transmitting different blends of hydrogen, noting that the design pressure of a hydrogen pipeline is a function of the specified minimum yield strength S, pipe nominal wall thickness t, pipe outer diameter D, a design factor F, longitudinal joint factor E, and a carbon steel pipeline material performance factor H_f:

$$P = \frac{2St}{D} FETH_f \tag{5.1}$$

The primary difference between the design pressure equation for hydrogen and that for natural gas is the material performance factor H_f, which accounts for the adverse effects of hydrogen on the mechanical properties of carbon steel pipelines. B. Wang et al. (2018) provide values of H_f for different yield strengths and design pressures according to ASME B31.12-2014. They also note that the design factor F, which varies according to location class based on factors such as the number and proximity of buildings intended for human occupancy, is different for hydrogen than for natural gas. With these factors, existing pipelines can be assessed to determine which meet the ASME B31.12-2014 design requirements for hydrogen pipelines. Those that do not must be replaced or de-rated to an acceptable pressure. It should be noted that based on ASME B31.12-2019 (American Society of Mechanical Engineers 2019), many existing pipes in the United States would need to be rated with a design factor of 0.4 or 0.5 because they will need to be assessed using Design Option A instead of Design Option B, the latter of which allows Location Class 1, Division 2 pipes to have a design factor of 0.72. Design Option B requires more rigorous testing than Design Option A, and for older pipes, the heats from the original construction material necessary to perform that testing are likely not available. Many existing natural gas transmission lines in the United States currently operate at or near 72% of specific minimum yield strength (consistent with a 0.72 design factor) (Research and Innovative Technology Administration and Pipeline and Hazardous Materials Safety Administration 2008), meaning that these pipelines would either need to be de-rated significantly or supplemented with new pipes in order to reduce the operating pressure to levels that would correspond to a hydrogen design factor of 0.4–0.5. Either approach has significant ramifications for project economics, either through lost transmission capacity or through the required capital expenditures for new pipes.

B. Wang et al. (2018) employ the ASME B31.12 code to determine which pipelines need to be replaced and what their diameter and wall thickness should be, along with the sites of new compressor stations if needed, the flow rate and operating pressure in each pipeline at each node, and the total construction cost. The objective function in their model is to minimize the total annual operating cost, which includes the annual depreciation cost of substituted pipelines, the annual depreciation cost of newly built compressor stations, and the annual operating cost of compressors. Constraints in their model include pipeline flows, pressures, pressure drops, pipeline substitutions, compressor station construction and operation, and linearizations. They analyze two case studies—a pipeline network without branching and a second pipeline network with two branches—and explore how different hydrogen injection rates and design factors influence the economics of hydrogen blending. They find that the total cost of the conversion is highly dependent on the amount of hydrogen blended and the design factor of the pipeline. In the network without branching, for example, blending 5% hydrogen into a network with a design factor of 0.6 results in marginal increased costs. Blending 10% hydrogen, however, results in a 68% increase in total costs relative to the existing network. Blending 5% or 10% hydrogen into a network with a design factor of 0.5 increases total costs by a factor of 4.8 and 5, respectively. The authors find similar results for a scenario with a branching pipeline network. Note that the study does not compare against the economics of building new dedicated hydrogen pipelines but rather assumes that upgrading existing infrastructure would always be more cost-effective due to lower related cost such as land expropriation and on-site surveying costs. Their model is also specific to transmission networks and does not consider pipe materials used in distribution networks or components such valves, pressure regulation stations, or metering stations.

Considering the broad literature on the economics of hydrogen blending into natural gas, it is clear that there is great interest in using this method to increase renewable penetration and decarbonize sectors that rely on natural gas, and in many cases doing so may be economically viable. There is no consensus, however, on the amount of hydrogen that can be blended, which parts of the natural gas networks can accommodate hydrogen, or how to best assess natural gas networks for hydrogen compatibility. There is consensus, however, that these details will be case-dependent. It is clear that a holistic, case-dependent model applicable to specific natural gas transmission and distribution networks would be a valuable tool to determine whether hydrogen blending is economically viable.

6 Pilot Projects and Experiences

This section discusses demonstrations of hydrogen blending completed to date and planned over the next 2 years. After providing an overview of the limited number of projects completed or in progress within the United States, we segregate foreign pilot projects and experiences into three types based on the systems on which they analyze blending impacts: (1) end-use appliances in the residential/commercial sector or end-use in larger-volume applications in the industrial sector such as power generation, (2) natural gas distribution systems, and (3) natural gas transmission systems. For the sake of this discussion, all hydrogen blend percentages are given on a volumetric basis.

6.1 U.S. Overview

To date, Hawaii Gas, New Jersey Natural Gas, and SoCalGas are the only U.S. utilities to have successfully demonstrated blending of hydrogen into natural gas transmission and/or distribution lines. Hawaii Gas has been using an average of around 12% blend of hydrogen sourced from a synthetic natural gas production plant since the 1970s in Oahu's gas network (Hawai'i Gas 2022). It is worth noting that prior to the SNG production plant's construction, Hawaii Gas transported town gas, a gas mixture containing up to 50% vol. hydrogen, within sections of their transmission and distribution network for decades prior. In this network, both the transmission and distribution portions operate at relatively low pressures (around 450 psi and 12 psi, respectively) compared to transmission and distribution networks in the lower 48, and the majority of Hawaii Gas's end-users are utilizing the mixture for cooking or water heating purposes. Meanwhile, in October 2021, New Jersey Natural Gas began injecting 65 kg/d of hydrogen into an 8-inch, 60-psi distribution line. This volume amounts to less than 1% hydrogen by volume (S&P Global 2022). The University of California Irvine, SoCalGas, and the National Renewable Energy Laboratory partnered in 2016 to develop a smaller-scale blending demonstration (Domptail et al. 2020). This study concludes that its 13-MW gas turbine can handle natural gas mixtures with up to 3.8% hydrogen by volume with no discernible impacts to operations or emissions. These results, however, should not be extrapolated to other equipment, because they were shared via an interview between Pipeline Research Council International and the University of California Irvine and no details on the experiment or results could be found in the peer-reviewed literature. Lastly, SoCalGas is developing one of the first projects to test hydrogen blends in a natural gas network with their H_2 Hydrogen Home (SoCalGas 2020). This project will outfit a home with solar panels, a battery, an electrolyzer to convert solar energy into hydrogen, and a fuel cell to turn that hydrogen back into electricity. The hydrogen will also be blended with natural gas and fed to the home's appliances.

It is worth noting that in the 1990s Air Liquide purchased two crude oil pipelines and converted them to operate with 100% hydrogen. One of them initially operated at 700 psig for 6 months until it ruptured due to corrosion, after which approximately half of the 140 mile pipeline continued to operate at 350 psig until at least 2005. The other pipeline consisted of 34 miles of pipe of varying grade and wall thickness and operated at 740 psig from 1996 until at least 2005 (Air Liquide 2005). These pipes illustrate that there exists some precedent in the U.S. for converting pipelines designed for hydrocarbons to operate with hydrogen and achieving successful operation with some modifications.

6.2 State of Blending Demonstrations in End-Use Applications

Many studies and demonstrations have explored in depth the impacts of hydrogen in natural gas distribution networks, serving primarily residential and commercial end-users, with hydrogen blend ratios ranging from as little as 2% to as much as 30%. The types of end-use applications have generally been limited to commonly found appliances such as boilers, stoves, and furnaces. Current active projects seek to test those limits, specifically on residential appliances at 100% hydrogen. It is not yet clear, however, up to what percentage of hydrogen is acceptable in existing appliances manufactured for natural gas combustion. Hydrogen compatibility of end-use appliances could be a limiting factor if the presence of hydrogen requires end-users to spend additional capital to modify existing equipment or make new purchases. Key criteria for end-use appliances when considering the use of hydrogen-natural gas blends include Wobbe Index, calorific value, light back (or flash back), and relative density. These criteria enable evaluation of hydrogen blending impacts to private consumer safety, end-use device reliability, and total cost of ownership for residential and commercial appliances. The inclusion of blending demonstrations in domestic end-use appliances in this section is meant to provide perspective on what challenges continue to persist in understanding increased blending limits, particularly at the burner tip, because these limits are key to understanding challenges in transmission and distribution network blending.

In May 2021, CSA Group published their findings on various blend amounts in residential end-use equipment (Suchovsky et al. 2021), specifically in space and water heater appliances, at blend percentages of 0%, 5% and 15%. Appliances were tested for input rate, ignition and burner operating characteristics, combustion products properties, and gas leakages per applicable CSA/ANSI Z21 series standards. Their conclusions were that testing these various input fuel mixes demonstrate a consistent decrease in CO_2 emissions and heat outputs and that no other obvious trends were noted in regard to other behaviors. The study also saw relatively unremarkable changes in NO_x emissions, with one exception in unvented space heaters. They tested two types of space heaters; the first used a blue flame burner type, while the second used infrared. Experimenting and measuring NO_x emissions according to South Coast Air Quality Management District protocols, the study found that the infrared space heater emitted 20% more NO_x emissions than pure methane under a 15% hydrogen blend. All other appliances tested resulted in NO_x emissions well below acceptable levels. However, the authors do note that further validation of results would require a larger sample size, other types and capacities of appliances, and additional testing conditions to further validate their results.

The HyDeploy project in the UK, which commenced operation in 2019, sought to demonstrate with evidence that hydrogen can be blended into the existing UK gas distribution network (Isaac 2019). It established a test community at Keele University, where 101 homes and 30 faculty buildings were fed a blended mixture. Phase 1 of this project concluded in 2020 and found that domestic appliances operated safely with a hydrogen blend of up to 28.4% by volume (Isaac 2019). This report discloses little technical or performance information on the results of the experiments, but it does make a number of observations, including: (1) all critical gas cooker component temperatures remained within acceptable limits; (2) flame-ionization current reduced with the addition of hydrogen; (3) flame-out due to flash back began only at 80% hydrogen, whereas some appliances flamed out at 100%; and (4) CO_2 emissions reduced by up to 0.5%. However, it should be noted that a wider range of appliances should be tested to further validate results. Lastly, for reference, all gas appliances sold in the UK are certified with reference gas G222, which allows up to 23 mol % hydrogen (Isaac 2019).

The UK presents a unique case because before 1967, domestic gas or “Town Gas” contained 50% hydrogen. Town Gas was produced from gasified coal but was eventually phased out over a 10-year period, completing in 1977 after the discovery of North Sea reserves (Isaac 2019). Furthermore, another UK study by Haeseldonckx and D’haeseleer (2007) looked at the average Wobbe Index of gas consumed in UK appliances and how varying hydrogen blends impact the index. Noting that average Wobbe Index in the UK varies from 41 MJ/Nm^3 to 48 MJ/Nm^3 for lean natural gas and 48 to 58 MJ/Nm^3 for rich natural gas, they found that a blend of 65%–85% hydrogen injected into lean gas tested the lower bounds of the Wobbe Index, with 75% hydrogen performing the worst. They note, however, that negative impacts of this mixture start disappearing at 90% and greater hydrogen. This finding is consistent with another experiment conducted by Boulahlib, Medaerts, and Boukhalfa (2021). In this experiment, impacts of blended hydrogen and natural gas on a domestic boiler were analyzed. They noted that Wobbe Index decreases linearly with incremental hydrogen with a minimum of “around 80% hydrogen,” but then increases gradually at higher hydrogen amounts.

The findings from the HyDeploy project were corroborated in the THyGA (Testing Hydrogen admixture for Gas Applications) project, where two of the project deliverables were to (1) theorize impact of a hydrogen blend on a variety of end-use residential and commercial applications, and (2) conduct an in-depth literature review of impacts of blended hydrogen on end-use appliances (Schaffert et al. 2020). This project defines eight categories of appliances: gas boilers, combined heat and power appliances, gas heat pumps, water heaters, cooking appliances, catering appliances, space heaters, and radiant heaters. The study notes that both technological implementation and fuel properties of each appliance play a critical role in the efficiency and safety of combusting a hydrogen blend. As an example, a premixed combustion process will react differently than a non-premixed system. Combustion control systems are key to adequately handle higher and fluctuating levels of hydrogen in the blended gas because combustion efficiency and flue gas composition are impacted by shifted combustion conditions. For example, hydrogen introduction into delivered gas for a premixed uncontrolled combustion process leads to a higher stoichiometric air-fuel ratio, potentially causing flame lift. Higher stoichiometric air-fuel ratios, however, counteract the increased flame speeds and elevated combustion temperatures associated with hydrogen introduction (Schaffert et al. 2020).

The THyGA project conducted a literature review of 36 studies that tested various levels of hydrogen blending on residential end-use appliances. The literature review selection process was subject to a rigorous, four-stage down-selection routine whereby the final selection parameters of the studies specified that all had to reference a specific appliance technology and produce quantitative results. All theoretical studies were excluded. The studies covered applications below 150-kW nominal heat output to exclude any large-scale industrial equipment, with the majority of studies analyzing mixtures up to 30% hydrogen blend. The THyGA project identified six key topics for each of the 36 studies covered: CO emissions, NO_x emissions, overheating/flame temperature, flashback, operatibility, and efficiency. The two emissions topics were the most covered, over 21 times each, followed by flashback at 14 times and the remaining topics covered 11 times or fewer. The authors of the THyGA project found strong agreement among the literature for the following statements regarding the addition of hydrogen (Schaffert et al. 2020): (1) flame stability range extends toward leaner conditions, (2) air ratio moves toward leaner conditions, (3) power output decreases, and (4) appliance components do not overheat. In this context, "strong agreement" is defined as more than 50% of the studies covering a topic agreeing on a result.

Because flashback was the most covered operatibility topic, it is discussed further here. Flashback may occur because the addition of hydrogen increases combustion velocity, which in turn impacts flame stability. The larger the combustion velocity relative to the flow velocity, the closer toward the burner the flame will move and increase the risk of flashback, which could damage the appliance. The general THyGA report conclusion on flashback was that it was not a major factor in blends of up to 30% hydrogen in household boilers or cooktops; however, the authors agree that in mixtures of 50% hydrogen by volume and higher, the risk of flashback increases, and even more so in blends exceeding 80%. It is worth noting that of the 14 studies covering flashback, only 3 analyzed blends of 60% hydrogen or more, but all 3 were in agreement that flashback occurred with 60% and higher hydrogen, while 10 studies had analyzed the impact of up to 30% hydrogen and all had agreed flashback was not a risk at up to 19%, with the first occurrence happening at 20%. Contrarily, there was general disagreement among the studies regarding the following statements: (1) no ignition delay, (2) combustion control working flawless, and (3) efficiency decreases. It is worth noting, however, that only one-third or fewer of the total studies used in this analysis covered these topics, indicating there is still more work to be done on these topics before drawing any firm conclusions.

Lastly, another key end-use demonstration will be conducted by Scotland's SGN, a major gas distributor. SGN kicked off the H100 Fife project, which aims to supply approximately 300 homes with 100% hydrogen by 2023 in Levenmouth (SGN 2022). This project will produce hydrogen via offshore wind-to-electrolysis and inject the hydrogen into the local gas distribution grid. The project will employ newly constructed pipeline, but the company has not specified whether the appliances in this network will be tuned for pure hydrogen or will be appliances available today for natural gas consumption.

As can be seen in this subsection, a number of blending demonstrations on end-use appliances have been completed, and many more are ongoing or planned. The key objective of these, however, has been primarily to demonstrate how appliances may behave when consuming a hydrogen-natural gas blend, but none of them address the commercial aspects of this practice. Questions remain, such as how to charge customers for a blended mix when hydrogen is generally more expensive on a dollar/Btu basis and who bears the cost of potential failures of equipment. As these hydrogen-natural gas blend consumption practices mature, these questions will be ever more critical to understand.

6.3 State of Blending Demonstrations in Distribution Systems

The vast majority of blending demonstrations around the globe are focused on the distribution pipeline network. This is primarily due to the relatively low operating pressures of distribution lines, which reduce safety concerns relative to blending into higher-pressure flow-rate transmission lines, which employ high-powered compressors to move gas along the system.

The majority of demonstration projects found in recent literature, primarily located in Europe, initiate their blend targets at low hydrogen contents between 3% and 5% by volume. Consensus exists throughout the literature that 5% blend is tolerable for many end-use applications, and even higher concentrations may work for many residential applications (Domptail et al. 2020; Haeseldonckx and D'haeseleer 2007; Schaffert et al. 2020). Several other demonstration projects in Italy, Netherlands, France, and the UK blend up to 10% hydrogen into natural gas (GRTgaz et al. 2019; Isaac 2019; Snam 2020; Taminiau 2017), and several more blend up to 20% (Domptail et al. 2020). Very few existing projects attempt blend percentages above 20% (Schaffert et al. 2020). The HyDeploy project, which tested a 28.4% blend in a distribution grid demonstration (Isaac 2019), is one exception, as is the Enertrag Hybridkraftwerk project in Germany, which tested blends up to 70% hydrogen (Iskov and Rasmussen 2013) serving local heating and transport needs. There are other projects in Europe that have announced intentions to blend hydrogen into transmission and distribution pipelines but do not mention the extent of blending. An example of this is Westküste100 (Westkueste100 2022).

Enbridge and Cummins have piloted a blending demonstration (Enbridge 2022) in Markham, Ontario. This $5.2-million project stores excess electricity in the form of hydrogen and injects the hydrogen into Enbridge's gas network serving 3,600 customers. The Markham Power-to-Gas facility was commissioned in 2018 and provides up to 2% hydrogen by volume.

Australian Gas Network's $14.5-million HyP SA (Hydrogen Park South Australia) (Australian Gas Network 2022a) is currently blending 5% hydrogen into the local natural gas distribution system at the Tonsley Innovation District. End-users will not be required to adjust or purchase new appliances to accommodate this mix. Renewable hydrogen is produced from a 1.24-MW PEM electrolyzer powered by wind and solar resources that outputs up to 20 kg of hydrogen per hour with 40 kg of on-site storage supplying a blended mix to more than 700 customers. The project aims to achieve blends of 10% by volume by 2030, with the long-term vision of achieving 100% hydrogen by no later than 2050. Australian Gas Network is currently in the planning and design phase of another much larger blending demonstration, HyP Murray Valley (Australian Gas Network 2022b). It is a $44-million project that is expected to commence blended flows in 2024 and will utilize a 10-MW electrolyzer, producing up to 177 kg of hydrogen per hour.

Finally, to the authors' knowledge, only a limited number of projects are attempting to blend even higher hydrogen concentrations of up to 100% in existing natural gas infrastructure. The H21 Leeds City Gate Project, launched in 2016, is one such project (H21 Leeds City Gate Team 2021). The project is currently in Phase 2, which will focus on operational safety demonstrations, and will proceed to Phase 3, live trials (timing not yet known). Phase 1 focused primarily on experimentation and testing of higher hydrogen blends on various materials and assets. Some summary results of these tests include: (1) assets that were gastight on methane were also gastight on hydrogen; (2) hydrogen volumetric leak rates were observed to be 1.1 to 2.2 greater than leak rates for methane; (3) none of the polyethylene assets leaked, whereas cast, ductile, and spun iron demonstrated similar leakage rates; (4) four types of joints were responsible for most of the leaks: screwed, lead yarn, bolted gland, and hook bolts; and (5) all repairs that sealed methane leaks were also effective when tested with hydrogen (H21 Leeds City Gate Team 2021).

6.4 State of Blending Demonstrations in Transmission Lines

Numerous studies and demonstrations of hydrogen blending in existing gas transmission lines have taken place across Europe over the past several decades, which has more recently garnered interest from numerous transmission system operators in studying what a European-wide transmission network could look like via a European Hydrogen Backbone (A. Wang et al. 2020; Cauchois et al. 2021).

The Netherlands has been heavily involved in this effort of demonstrating blending into an existing natural gas transmission pipeline. The Gasunie project covered in Huising and Krom (2020) converted a natural gas pipeline operating at 40 bar to transport a blended mix with 80% by volume hydrogen at a pressure of 35 bar to a fertilizer plant 11 miles from the production source in a 16-inch-diameter line. Several other ongoing European projects are studying the feasibility of converting natural gas transmission networks to handle higher concentrations of hydrogen. Table 7 lists these projects.

Demonstrations of blends in natural gas transmission lines have been limited outside Europe, with only a handful currently now underway in the region. Per Table 7, some demonstration projects have indicated that hydrogen blends of up to 10% and 20% by volume are noncritical for transmission lines. The Snam Contursi Trial, for example, has been active since 2019 and has demonstrated that a 10% by volume hydrogen blend in transmission networks is feasible; however, little has been made public regarding the pipeline operations or integrity in this project to date (Snam 2020). A Danish demonstration, the "Energy Storage - Hydrogen injected into the Gas Grid via an electrolysis field test" project successfully demonstrated that 12% hydrogen by volume is feasible in a closed-loop, high-pressure system consisting of infrastructure components in both the transmission and distribution grids (Munkegaard Hvid 2020). National Grid's FutureGrid project in the UK will study whether the National Transmission System will be able to tolerate higher concentrations of hydrogen, up to 100%. The demonstration site is currently under construction, with tests expected to happen over the course of 2022 (National Grid 2022).

Table 7. Active Blending Projects in Gas Transmission Networks

Project Name	Project Participants	Countries	H_2 Blend Percent	Additional Project Details	Project Period
MosaHYc (GRTgaz 2020b)	GRTgaz, CREOS	Germany, France, Belgium	100	Study conversion of two existing, 100-km gas transmission pipelines to pure hydrogen supplied by a 60-MW electrolyzer at 20,000 m^3/h	2021–2022
FenHYx (GRTgaz 2020b)	GRTgaz, RICE	France	0–100	Understand impacts of higher hydrogen concentrations in natural gas transmission and distribution systems (0–100 bar)	2021–ongoing
Jupiter 1000 (GRTgaz 2022)	GRTgaz, TEREGA, CEA, CNR, RTE, Pc-PHy, Ler-oux&Lotz, Khimod, GPMM	France	0–6	1-MW P2G (PEM and alkaline) and methanation with carbon capture on industrial plant. Injection into GRTgaz's network since 2020 with three industrial end-users. Understand life cycle assessment, TEA, and physical impact of hydrogen on the grid and end-users.	2014–2023
HyNTS FutureGrid (National Grid)	National Grid	UK	N/A	Study impacts of blending hydrogen into decommissioned assets at a test facility at Spadeadam to demonstrate the NTS can transport hydrogen.	May 2021–March 2023
Snam Contursi (Snam 2020)	Snam	Italy	10	Study impacts of up to 15% blending demonstration of 10% hydrogen into gas transmission network to two customers—a pasta factory and mineral water bottling company.	2019–ongoing
Energy Storage (Domptail et al. 2020)	Energinet, Evida, Danish Gas Tehcnology Centre	Denmark	25	Study impacts of up to 25% hydrogen in high-pressure (80-bar) transmission network. No significant leaking detected or upgrades required.	2020–2021
H21 (Northern Gas Networks 2022)	Funded by Ofgem and led by Northern Gas Networks	UK	100	Other partners include: Cadent Gas, SGN, West and West Utilities, National Grid, DNV, and the Health and Safety Executive. The goal is to establish confidence in repurposing existing gas network to 100% hydrogen.	2021–ongoing
H2HoWi (Nhede 2020)	E.ON, Westnetz GmbH	Germany	100	A first-of-kind natural gas distribution pipeline conversion in Germany that will supply pure hydrogen to four commercial customers.	2020–2023

7 Discussion

The wide range of topics summarized in the previous sections highlights significant international interest in blending hydrogen into natural gas pipeline systems to achieve multisector decarbonization and early-market hydrogen distribution. The findings of this literature review elucidate several key practical, economic, and theoretical insights that are consistent across the literature. Nonetheless, significant uncertainty exists in the reviewed literature on topics such as blending limits and equipment compatibility. This section discusses the key points of consensus and areas of disagreement and/or uncertainty within the reviewed literature, along with key questions to address in future Pipeline Blending CRADA research.

7.1 Areas of Consensus Within the Literature

This review notes several consistencies in the covered research on technical and economic assessments involving hydrogen blending.

It is well known that the presence of hydrogen in natural gas pipeline networks negatively impacts steel's mechanical properties. Multiple studies have established that fatigue crack growth rates substantially increase in the presence of hydrogen, even at low hydrogen partial pressures (or more rigorously, fugacity) near 1 bar. Fracture resistance, on the other hand, has been shown to decrease most significantly for low partial pressures and then continue to decrease more modestly at higher partial pressures. Studies have also established, however, that hydrogen partial pressure (or fugacity) is not the sole parameter influencing fatigue crack growth and fracture resistance. Both properties are also dependent on the state of the pipeline and operating conditions. For example, under high stress conditions, the load ratio has a more dominant effect on fatigue crack growth than hydrogen partial pressure (in the context of blending). This may indicate that if a steel pipeline under high stress could handle blends with low compositions of hydrogen, it could likely handle blends with higher compositions. Conversely, hydrogen partial pressure (or fugacity) is a significant variable for fatigue crack growth rates in low-stress environments and should be accounted for. Multiple studies have also found that hydrogen affects polymer pipeline material properties; however, the degree of the hydrogen's effect is less clear for polymer pipeline material than for steel.

Multiple studies assessing the impact of hydrogen blending in natural gas mixtures find consistent trends in transmission pipeline pressure drop and gas compression, which is not surprising because the models for pressure drop and compression are derived from thermodynamics and fluid transport theory. Studies also agree that centrifugal compressor operational envelopes will shift with gas composition and are a key blending constraint consideration; specifically, adding hydrogen while still achieving the same pressure rise requires an increase in compressor speed that will eventually meet impeller stress limits. The precise hydrogen blend beyond which compressor operation is infeasible is case-dependant, however, as different compressors are designed at different points relative to their maximum possible speed. Multiple studies also find consistent performance results when analyzing the effects of hydrogen blending on combustion in gas-driven prime movers. Gas turbines may require physical equipment modification to enable greater fuel flexibility to maintain equipment life, emission levels, and efficient energy conversion. Conversely, tuning ignition timing and air-fuel ratios may be sufficient to allow reciprocating engines to operate with higher-hydrogen-composition fuel.

Network modeling and economic analyses indicate that hydrogen blending may create various natural gas pipeline bottlenecks that limit overall network energy transmission capacity. If constant energy transmission capacity must be maintained, hydrogen blending capacity may be constrained by reduced compression station capacity, excessive pressure drop, or maximum pressure constraints associated with specific sections of transmission pipeline. Hydrogen blending may also complicate efforts to maintain gas delivery specifications for distribution pipeline customers. These constraints could become the focus of pipeline retrofitting projects to enable greater hydrogen blending compatibility for a given pipeline network. A key focus for this Pipeline Blending CRADA is to identify and assess the economics of these potential projects.

7.2 Areas of Disagreement Within the Literature

Numerous reports and economic studies generally agree that natural gas pipeline systems can accommodate low levels of hydrogen blending without retrofitting projects (Melaina, Antonia, and Penev 2013; Altfeld and Pinchbeck 2013; Hodges et al. 2015; Gondal 2019). This group of studies as a whole, however, does not offer a clear consensus for defining generalized guidelines for hydrogen blending compatibility of natural gas transmission and distribution networks. This lack of consensus could be attributed in part to the fact that the general understanding of hydrogen blending challenges has improved over time. The uniqueness of natural gas pipelines systems is another contributing factor. Natural gas pipeline systems also vary in pipeline materials of construction, non-pipeline equipment, and gas composition. For example, original equipment manufacturers have provided technology options that are compatible with processing gases containing varying amounts of hydrogen (an example for gas turbines is provided in Kutne et al. (2020)). Some natural gas pipeline networks may have been designed with these technology options, and some likely have not. Generalized pipeline assessments tend to evaluate details indicating hydrogen compatibility on installed equipment with varying levels of depth, which may lead to conflicting conclusions of these assessments. Future case-by-case assessments would benefit from including these pipeline network characteristic data.

7.3 Topics Requiring Further Research

The current state of literature indicates that substantial research remains before widespread hydrogen blending implementation can occur. There exists a need for additional testing on both steel and plastic pipeline materials implemented in the U.S. natural gas pipeline system to identify and confirm relationships between hydrogen presence and fatigue, crack growth, and failure rates. Additional research can also explore the impacts of hydrogen on previously installed valves, meters, and pressure regulators to clarify short- and long-term functionality over a wider range of conditions. Much of the concerns around hydrogen material impacts extend to materials applied within compressors, prime movers, valves, meters, and pressure regulators. Pipeline maintenance and repair will also be crucial to reduce risk on pipeline failure when implementing hydrogen blending, and demonstration projects can help identify what operations and maintenance activities need to change and which will be most critical. Development of unique transmission system and distribution system assessment methodologies at various blend levels, including definition of incremental O&M activities, would ensure consistent evaluation, conversion standards, and operational safety performance.

Current research in line pipe steels and welds have focused on post-1990s material samples, whereas most of the U.S. natural gas pipeline system is composed of pre-1970s (or vintage) steel (Keifner and Rosenfeld 2012). This vintage steel line pipe may contain higher quantities of defects due to initial lower manufacturing quality and inherent wear from operation over service lifetime. The population and extent of defects will likely have a significant impact on pipe suitability for hydrogen blending and remaining service lifetimes, especially for environments containing hydrogen. ASME B31.8, which provides guidance on steels used in pipelines (American Society of Mechanical Engineers 2020), was adopted into federal regulation in 1970 after the manufacture and installation of certain vintage pipeline steels (National Archives Code of Federal Regulations 2020). The material qualities of these vintage pipes and their response to hydrogen environments introduce considerable operational uncertainty and safety risks. Additional fatigue and fracture testing is needed to establish limiting behavior in gaseous hydrogen environments, especially for vintage seam welds and hard spots. The impact of non-hydrogen gaseous impurities (such as potential inhibitors) on steel pipeline fatigue and fracture behavior is not well understood, although new data suggests that impurities do not mitigate hydrogen effects on long time scales.

Although there are many practical demonstrations of hydrogen blending in natural gas distribution pipelines and end-use, formal materials characterization on polymer pipelines is limited. Hydrogen appears to impact the mechanical properties of polyethylene, although the physical mechanisms describing these impacts are not yet completely clear. How and to what extent the change in mechanical properties relates to long-term performance (or lifetime) of pipes is also unknown. Many of the existing data have been generated with polymer pipe body sections rather than joints, which could be a focus of future research. Furthermore, PE grades are further differentiated by manufacturer resin formulations. The impact of different polymer resin formulations on hydrogen compatibility should be evaluated.

Publications on the effects of hydrogen on installed valves, meters, and pressure regulators are relatively sparse compared to pipeline transport, gas compression, and prime movers. This is likely because the latter group probably has a larger impact on overall pipeline economics. Existing relevant literature provides hydrogen compatibility for valves, meters, and pressure regulators in terms of generalized limits, and what few studies were found exploring the integrity of these devices disagreed on the suitability of using these existing devices in a hydrogen-blended network. Performance testing of multiple valve types and meters under a greater variety of operating conditions and configurations would strengthen the collective literature, as would the testing of elastomers and seals that are critical for valve and meter performance. Despite the fact that pressure regulators are frequently employed in city gate stations and distribution pipelines, the effect of hydrogen on pressure regulator performance is also addressed minimally in the literature. Published research regarding domestic and commercial end-use appliances utilizing 100 vol % hydrogen is limited at the time of writing. GTI has ongoing research in domestic and commercial end-use appliances utilizing hydrogen blends with hydrogen compositions greater than 50 vol %, as well as pure hydrogen gas (GTI 2022).

Current maintenance and repair procedures for natural gas pipelines may require adjustments to account for hydrogen's impact on steel fatigue and crack propagation. Currently, there is limited published research that recommends changes to transmission pipeline maintenance programs for hydrogen blending (Domptail et al. 2020). Two reviews agree that hydrogen blending may necessitate more frequent pipeline inspection to minimize the probability of pipeline failures (Melaina, Antonia, and Penev 2013; Domptail et al. 2020). This frequency may depend on key factors such as hydrogen composition, pipe loading, and existing defects (Domptail et al. 2020). Additionally, the criteria for assessing pipeline defects for acceptability may change for a given hydrogen blend percentage. Recommendations on how to adjust repair and rehabilitation methods for pipelines servicing natural gas-hydrogen blends are not well established and could benefit from further research and technical demonstration.

Finally, more research is needed to assess the overall potential of hydrogen blending to contribute to economywide decarbonization and how to best scale up hydrogen blending efforts to achieve maximum impact. To fully decarbonize sectors currently served by natural gas, hydrogen blending must serve as an intermediate step between today's natural gas infrastructure and future pure hydrogen infrastructure. Blending hydrogen into pipeline systems at low hydrogen compositions should be seen as an incremental solution toward decarbonization because the resulting carbon emissions reduction for end-users is marginal. Substantial carbon emissions reductions through hydrogen blending are achievable when the hydrogen composition in pipeline gas is greater than 80% (Goldmeer 2019). For instances in which rapid decarbonization is desired or for which substantial modifications must be made to pipeline networks to achieve any significant level of hydrogen blending, it may be more advantageous to convert a natural gas service pipeline to transport pure hydrogen rather than make incremental modifications to enable intermediate blends of hydrogen with natural gas. Pipeline material, equipment, and end user compatibility challenges that are associated with hydrogen blending are also present for projects converting service lines from natural gas to pure hydrogen, as are the knowledge gaps related to hydrogen blending.

Furthermore, meeting the entirety of U.S. natural gas demand with hydrogen produced from electrolysis would require vast amounts of electricity, significant quantities of water (though displacing natural gas with electrolysis-based hydrogen would reduce or eliminate water consumption from gas extraction processes such as fracking), and construction of additional transmission pipeline capacity, requiring the advocacy of policymakers and the public. Fully capturing the environmental and economic benefits and challenges of hydrogen blending requires coordinated modeling of both the electricity grid and the gas network, which are linked today via gas-consuming power plants and could be linked in the future via hydrogen-producing electrolysis plants and hydrogen-consuming fuels. Such a modeling framework could capture systemwide implications such as expanded renewables and electricity transmission capacity to meet hydrogen production demand, water requirements for hydrogen production, and the impact that both systems have on electricity and gas prices. Coordinated modeling could also help establish scenarios for scaling up hydrogen blending efforts and the associated decarbonization benefits by considering potential electricity grid transformation scenarios, identifying potential bottlenecks for hydrogen blending efforts, and determining where and when investments in gas infrastructure hydrogen preparation can have the greatest impact.

This level of analysis must start by adequately capturing pipeline hydrogen preparation economics. The majority of prior hydrogen blending economic studies have not fully considered all major cost constraints that will factor into a network's overall hydrogen compatibility and/or how to modify the network to accommodate hydrogen. Examples of such considerations include the impact of hydrogen on lowering maximum pipeline operating pressure for a pipeline constructed of a given material (for which ASME B31.12 provides guidelines), compressor station tolerance to hydrogen and modification or replacement costs, prime mover capacity, pipeline inspection costs, valve and meter inspection and replacement costs, and the opportunity cost of reduced energy transmission capacity. The effects of hydrogen on pipeline life could also have significant implications for project economics, but prior economic assessments have not explored this topic in depth. While several network modeling studies have assessed the technical feasibility of hydrogen blending in either transmission or distribution pipelines, to the authors' knowledge, no single study has compared the economic and environmental benefits of potential hydrogen blending projects applied to different sections of the natural gas pipeline system (e.g., blending into distribution networks instead of transmission networks). Comparisons of the feasibility and economics of different natural gas sector decarbonization methods such as hydrogen blending, new-built pure hydrogen infrastructure, and synthetic natural gas production are limited (Wartsila 2020; European Commission 2021) and do not fully assess all costs and considerations for these strategies. These analysis subjects should all be the focus of future hydrogen blending economic research.

8 Conclusion

This report provides a comprehensive review of literature on the opportunities and challenges associated with blending hydrogen into natural gas pipeline infrastructure. The suitability of natural gas pipeline systems for hydrogen, even in low concentrations (e.g., 1–10 vol %), depends on numerous factors, not the least of which is the condition of pipeline infrastructure and proposed operating conditions with blended hydrogen. This review of prior literature finds that taking a case-by-case approach in assessing natural gas pipeline networks will be necessary to thoroughly investigate blending opportunities and plan capital investment to extend the hydrogen compatibility of existing pipeline infrastructure. This report reviews studies on the assessment and extension of natural gas pipeline network hydrogen compatibility from experimental, theoretical, and practical studies focused on materials, individual equipment, facilities, networks, economics, and operations.

This review gleans several insights from the existing literature on hydrogen blending in natural gas. Case-by-case hydrogen blending assessments should leverage detailed information on hydrogen injection location, pipeline materials, installed pipeline equipment, end-use appliances, and supporting pipeline facilities to identify natural gas pipeline compatibility with hydrogen and necessary pipeline network modifications. Research on the impact of hydrogen on pipeline steels has demonstrated that the presence of hydrogen significantly affects both fatigue crack growth and fracture resistance, with the most significant degradation in these properties occurring with small increases in hydrogen partial pressure to around 1 bar. In high stress situations for hydrogen service, fatigue crack growth and fracture resistance are principally a function of operating pressure fluctuations and pipeline condition, with secondary consideration for hydrogen partial pressure. Research on polyethylene pipe materials has demonstrated that hydrogen has an impact on material density, degree of crystallinity, and some mechanical properties, but more research is needed to quantify the effects of these changes on mechanical performance and pipe life.

We have also identified several mature modeling approaches to analyze hydrogen's effect on pipeline network operations. These approaches can be extended with knowledge of hydrogen's impact on materials to perform improved techno-economic analyses to identify what extent of hydrogen blending is appropriate in a given natural gas pipeline network. In particular, ASME B31.12 provides guidelines on how to assess steel pipeline operating pressure for common pipeline materials given pipe diameter and thickness; alternatively, it could also be used to assess the suitability of existing natural gas steel pipes for accommodating hydrogen and to select materials and schedules for replacement pipes or new pipes added to accommodate additional capacity. It is important to recognize, however, that ASME B31.12 is designed for new builds of hydrogen pipe lines and leads to very conservative estimates for repurposing existing pipes for hydrogen service. Additional research on hydrogen's impact on pipeline material properties could inform future design guidelines and set the foundation for improving industry standards.

Pipeline operational studies have also demonstrated consistent hydraulic and thermodynamic impacts of mixing hydrogen with natural gas, and have highlighted that centrifugal compressors will require increases in speed to maintain pressure rise as hydrogen concentration is increased due to the low molecular weight of hydrogen. These compressors will likely reach impeller stress limitations before achieving 100% hydrogen blends, and the extent to which they can handle hydrogen will depend on their speed margins and materials of construction. Studies have also illustrated that operating existing gas networks with consistent pressure drop results in a reduction in transmissible energy capacity, and that operating with either constant pressure drop or constant energy transmission capacity would require substantially more compression work for high hydrogen concentrations than for pure natural gas. Future economic assessments must properly balance operational considerations such as de-rating the pressure of existing pipelines, increased compression energy requirements, and increased inspection frequency with upgrade capital costs associated with new pipelines, compression stations, and end-use application retrofits, as well as with opportunity costs associated with reduced energy transmission capacity. Additional pipeline network modeling could assist in identifying scenarios for technical demonstration and growth, and coordinated electricity grid and gas network modeling could provide greater insight into whether blending and eventually replacing natural gas with hydrogen is a viable pathway to economywide decarbonization. Technical demonstrations have also shown significant progress in developing the practical understanding to meet challenges in hydrogen blending, and additional demonstrations can fill current knowledge gaps and better inform decision makers on future blending projects.

This review will be followed by techno-economic model development for assessing opportunities to blend varying amounts of hydrogen into natural gas pipelines. This techno-economic model will incorporate research findings covered in this review to create a flexible, open-source software that will determine pipeline hydrogen compatibility and identify pipeline modifications necessary to extend compatibility on a case-by-case basis. This software will improve upon existing hydrogen blending analysis studies by comparing multiple energy delivery pathways, enabling greater location and time-based sensitivities and better quantifying economic and environmental benefits.

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